MINISTRY OF SCIENCE, ENERGY,

TELECOMMUNICATIONS & TRANSPORT

2022 Jamaica Integrated Resource Plan

2018 IRP Review and Update

A 20 Year Roadmap to Sustain and Enable Jamaica's Electricity Future

August 2023

This is a final document. This 2022 Integrated Resource Plan (IRP-2) update of the 2018 Integrated Resource Plan (IRP-1) is based on the best information available at the time of preparation. The action plan arising therefrom is subject to changes as new information becomes available or as circumstances warrant change. The IRP preferred resource plan is subject to update at least annually. This document was reviewed based on the sector stakeholders' comments and feedback. The data, conclusions and recommendations are final as report was presented to and approved by Cabinet.

TABLE OF CONTENT

Executive Summary 10
IRP-2 Dashboard 26
1. Background and Objectives 29
2. IRP-1 Preferred Portfolio Implementation Plan Review 30
2.1 IRP-1 Generating Resource Additions and Retirements 30
2.2 IRP-1 Transmission System Implementation Plan 31
2.3 Generating Resources Procurement 31
3. What has Changed since IRP-1 Development? 33
4. Main Features of the updated IRP-2 Preferred Portfolio 35
4.1 IRP Development Process Overview 35
4.2 Key Assumptions, Parameters and Changes 35
4.2.1. Demand Forecast 35
4.3 Renewable Portfolio Standards 38
5. Existing Generating System 39
5.1 Generating Resource Retirements 40
5.2 Independent Power Producer Contracts 41
5.3 Generating System Supply and Demand Balance 41
6. Generating System Expansion Options 43
6.1 Candidate Plants 43
6.2 Committed Capacity Projects 43
7. Economic and Technical Operating Parameters. 44
7.1 Base Year and Discount Rate 44
7.2 Economic Life of Generating Resources 44
7.3 Unserved Energy 45
7.4 Loss of Load Probability (LOLP) 45
7.5 Technical Operating Parameters 46

7.5.1. Reserve Margin 46

7.5.2. Electricity Sector Codes 46

7.6 Fuel Pricing and Forecasts 46

8. Candidate Plants Consideration 48

8.1 Technology and Costs Changes 48

8.1.1. Battery Energy Storage System (BESS) 49

9. Pathway to 50% Renewable Portfolio Standard 51

9.1 Demand Side Management 51

9.2 Energy Efficiency 52

9.3 Net Billing 52

9.4 Renewable Energy Technologies Options 52

9.4.1. Solar Resources 53

9.4.2. Floating Solar Power Plant Option 53

9.4.3. Wind Resources 54

9.4.4. Offshore Wind Resource Options 54

9.4.5. Wind Plant Repowering Options 54

9.4.6. Biomass and Waste to Energy 55

9.4.7. Battery Energy Storage Systems (BESS) 55

10. IRP-2 Scenarios 57

10.1 Scenario 1 & 2 – High System Load Demand and Fuel Forecasts 58

10.1.1. Result/Findings Scenarios 1&2 58

10.2 Scenario 3 – Seven Consecutive Days of Limited or No Solar and Wind Generation 58

10.2.1. Result/Findings Scenario 3 58

10.3 Scenario 4 – Increases in RE Investment Cost of 10% and 20% 59

10.3.1. Results/Findings Scenario 4 59

10.4 Scenario 5 – Assessment of Impact of Expired Fossil Fuel Plant(s) Extension 59
10.4.1. Result/Findings Scenario 5 ... 59
10.5 Scenario Assessments Summary ... 60
11. IRP-2 Preferred Implementation Plan ... 60
11.1 IRP-2 Resource Additions and Retirements ... 61
11.1.1. Procurement Lead Times ... 61
11.1.2. IRP-2 Generation Resource Additions ... 61
11.1.3. IRP-2 Resource Retirements ... 62
11.2 Summary of Changes Effected ... 63
11.3 Impact on Fuels Consumption and GHG Emissions ... 67
11.3.1. System Energy Mix ... 67
11.3.2. System Heat Rate ... 67
11.3.3. System Energy Mix Comparison IRP-1 and IRP-2 ... 68
11.4 Impact on Fuel Utilization and GHG Emissions ... 69
11.5 Preferred Implementation Plan Investment Costs ... 70
11.6 Avoided Generation Costs ... 78
11.7 Transmission Plan ... 79
11.8 The Updated Transmission Plan ... 80
11.8.1. Development of Base Transmission Plan ... 80
11.9 Transmission Development Plan ... 82
11.9.1. Existing Transmission System ... 82
11.10 IRP-2 Transmission Plan ... 83
11.11 IRP-2 Transmission Plan ... 85
11.11.1. Transmission Development Plans and Recommendations ... 86
12. Key Findings of Transmission System Plan ... 88

13. Key Findings of IRP-2 89
13.1 Key Findings 89

14. Recommendations 92
14.1 Planning Updates and Feasibility Studies 92

List of Tables

Table ES- 1: IRP-1 Preferred Portfolio Procurement Highlights 2018-2037 11
Table ES- 2: IRP-1 Transmission System Expansion Plan 12
Table ES- 3: Major Changes Since IRP-1 Development 14
Table ES- 4: IRP-2 Preferred Portfolio Highlights 2022-2041 15
Table ES- 5: Generation Expansion Scenarios Summary Results 17
Table ES- 6: Capacity Implementation Summary 19
Table ES- 7: IRP-1 and IRP-2 Summary Comparison 20
Table ES- 8 Key IRP findings 22

Table 2-1: IRP-1Preferred Portfolio Plan Highlights 30
Table 2-2: Retirement Schedule IRP-1 preferred Portfolio 30
Table 2-3: IRP-1 Transmission Expansion Plan 31
Table 3-1: Major Changes Not Anticipated in IRP-1 33
Table 4-1: Energy and Peak Demand forecast IRP-2 37
Table 5-1: Generating System Installed Capacity 40
Table 5-2: Minister's Retirement Schedule for JPS units 40
Table 5-3:PPA Expiry Dates 41
Table 6-1: Generating Plant Candidate Resources 43
Table 7-1: Generating Plant Planning Life 45
Table 7-2: Key Planning Parameters 46
Table 8-1: Wind Turbines Performance Trends 48
Table 9-1: 2021 Generation Energy Mix 53
Table 9-2:: Wind Resource at Selected Sites 54
Table 10-1: Scenario 1&2 – High Load Demand and Fuel Forecasts 58
Table 10-2: Scenario – Impact on System Costs PV (Variance) 60

Table 10-3: Scenario – Impact on System LCOE (Variance) 60
Table 11-1: Technology Lead Time to COD........ 61
Table 11-2: IRP-2 Preferred Portfolio Highlights 62
Table 11-3: IRP-1 & IRP-2 Comparison........ 63
Table 11-4: IRP-1 Preferred Portfolio Plan Details........ 65
Table 11-5: IRP-2 Preferred Implementation Plan Details........ 66
Table 11-6: System Energy Mix Progression........ 67
Table 11-7: Energy Mix IRP-1 & IRP-2........ 68
Table 11-8: Generating System Expansion Scenarios 71
Table 11-9: Share of Investments by Technology........ 71
Table 11-10: Preferred Implementation Plan PV Investment Cash Flow 73
Table 11-11: IRP-1 Preferred Implementation Portfolio Capacity........ 75
Table 11-12: IRP-2 Preferred Portfolio Implementation Plan 76
Table 11-13: IRP-2 Evolution of Renewable Energy Integration 77
Table 11-14: IRP-2 Avoided cost of Generation 78
Table 11-15: BESS Value Chain Identification........ 85

List of Figures

Figure ES- 1: Energy Mix Evolution 16
Figure ES- 2: IRP-2 Demand, Supply & Reserves........ 18
Figure ES- 3: Installed Capacity by Technology 18

Figure 4.1:Peak Demand Forecasts 37
Figure 4.2:Actual Peak & Energy Demand........ 37
Figure 5.1:Supply and Demand Balance........ 42
Figure 7.1:Fuel Prices Forecast........ 47
Figure 8.1: Wind Projects Price Trends 49
Figure 8.2: BESS Pricing Trend........ 50
Figure 11.1:IRP-2 Preferred Portfolio System Heat Rate........ 68
Figure 11.2: 2022 & 2030 Generation Energy Mix........ 69
Figure 11.3: Fuel Use & GHG Emissions........ 70

Figure 11.4:Generation Cost Components 72
Figure 11.5:JPS Transmission Grid 82

Glossary

Abbreviation	Terms Defined
ADO	Automotive diesel specification as fuel for generators
BOE	Barrels of Oil Equivalent
BESS	Battery Energy Storage System
Biomass	Biomass is a generation technology which converts agriculture waste projects into electricity
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Agency of the US Department of Energy providing forecasts for the study
GNI	Gross National Income
GoJ	Government of Jamaica
GWH	Gigawatt hours or thousands of megawatt hours generated or consumed in the course of a year
HFO	Heavy Fuel Oil consumed in power plant generation specified by percent sulfur by weight.
Hydro	Hydroelectricity generation using water flows to turn a generator turbine
Inverter	Wind and Solar generation which injects electricity into the electric grid without supplying inertia, or spin, to the system. Inertia is important to ensure reliable operation.
IPP	Independent power producers who contract to produce electricity for Jamaica
IRP	Integrated Resource Plan for this document is defined for the electricity sector
JPS	Jamaica Public Service Company
LNG	Liquefied Natural Gas as an imported fossil fuel imported to Jamaica in tankers and re-liquefied to be burned as generator fuel
Long Term Avoided Cost	Long Term Avoided Energy Cost is the benchmark under which JPS can exercise the option to build generation
MSET	Ministry of Science, Energy and Technology
MSETT	Ministry of Science, Energy, Telecommunications & Transport
NEP	National Energy Policy
NGCC	Natural Gas Combined Cycle a gas fired generator configuration which uses simple cycle generators and a steam generator to create a more fuel-efficient electricity generating source.
NREL	National Renewable Energy Laboratory
OUR	Office of Utilities Regulation
PPA	Power Purchase Agreement
Preferred Portfolio	Preferred Portfolio: from the various forecast scenarios, the resource and transmission mix which best meets the objectives
PS	Project Sponsor

PV, Solar	Photovoltaic electricity generation using solar radiation to produce electricity
QoS	Quality of Service
ROFR	Right of First Refusal, JPS' option to build electricity resources at lower than proposed levelized cost offered by a third party
RPS	Renewable Portfolio Standard, this is the percentage of renewable energy generation mandated in the generation mix
Short Run Avoided Cost	Short Run Avoided Cost is the short run ability to reduce supply of generation costs for the marginal resource
SMR	Small Modular Reactor (small nuclear fission reactor)
T&D	Transmission (above 69kV) and Distribution (below 69 kV) network used to convey electricity generation from source to load sinks
T&D Avoided Cost	Transmission avoided cost is the cost to avoid network upgrades by locating resources nearer load centers or avoiding expensive transmission upgrades
T&D or Network upgrades	Capital upgrades which ensure efficient and controllable resources operate on the transmission and distribution system according to reliability standards
Thermal Capacity	Fossil fuel generation which provides inertia to the electric grid
US$	United States Dollars
RE	Renewable energy resources including hydroelectric, solar PV, wind, biomass and Waste to Energy
WACC	weighted average cost of capital
WTE	Waste to Energy is a process of creating electricity from municipal waste streams

2018 Jamaica Integrated Resource Planning Update 2022

Executive Summary

This 2018 Jamaica IRP update 2022 (IRP-2) report presents the update of the Jamaican Electricity Sector 2018 Integrated Resource Plan[1] (IRP-1) draft report, which was published in January 2020, and edited in September 2020.

IRP-1 identifies the optimal resource plan (the Preferred Portfolio) to supply reliable, and economic priced electricity to meet consumers' demand over the period 2018-2037, while observing regulatory provisions, and the GoJ National Energy Policy objective of generating 30% of electricity requirements from renewable energy sources by 2030. The IRP process is intended to guide the procurement and retirement schedules of generating and transmission systems resources for the sector.

IRP-1 was developed by MSETT, in accordance with the provisions of section 7 of the Electricity Act (EA)[2] and in collaboration with sector stakeholders. The IRP is subjected to updates at least every two years or as circumstances warrant.

The IRP development process consisted of detailed modeling and analyses of the Jamaican electricity sector and involved a multi-step process as described in section 1.2 of the IRP-1 document. The input data and planning assumptions for the modelling and analyses were based on the best information available and known as at 2019 December.

[1] 2018 Jamaica Integrated Resource Plan, by Ministry of Science, Energy, Telecommunications & Transport Revised September 2020

[2] The Electricity Act, 2015

IRP-1 Preferred Portfolio Implementation Plan Highlights

Generation Expansion

The preferred portfolio implementation plan is the plan that meets the IRP stated objectives at least cost.

The main highlights of IRP-1 preferred portfolio implementation plan are provided in Table ES-1.

Table ES- 1: IRP-1 Preferred Portfolio Procurement Highlights 2018-2037

Procurement of: • 34.3 MW of run of river hydro plants comprising of 12 small hydro plants sited throughout the country in 2023. • 1,130 MW of new solar PV plant resources, comprising 107 MW in 2022, 107.5 MW in 2024, 77 MW in 2027and the balance of 839 MW between 2032-2037., • 121 MW of new wind resources, comprising 40 MW in 2022, 47 MW in 2024 and 34 MW in 2027. • 18 MW of waste to energy (WTE) plants and 20 MW of biomass plants in 2023. • Addition of 338.5 thermal natural gas fired candidate plants over the period 2024 -2036. • **Retirement of:** • 60 MW, and 124 MW of IPP Diesel plants in 2025, and 2026 respectively and 65.5 MW of IPP diesel plant in 2033. • 3 MW, 38 MW and 60.3 MW of wind plants in 2029,2032 and 2037 respectively.

The IRP-1 implementation plan schedule required that the procurement of the renewable plants identified for operations in 2023-2024 should have been started by the 2020 -2021 timeframe to ensure their scheduled operation dates, given their procurement lead times.

Transmission Plan

IRP-1 transmission planning studies were carried out to develop transmission resources implementation schedules for expanding and upgrading the transmission infrastructure in association with the generation resource preferred portfolio expansion plan to supply the forecasted load economically and reliably and to integrate the planned resources into the power system, subject to the grid interconnection guidelines and performance criteria.

The IRP-1 transmission plan was based on the siting of the new generation resources, the determination of the best locations of bulk step down substations and developed several transmission alternatives to interconnect the new generating plants to the load areas. Section 3.7 of the IRP-1 report details the transmission planning process. Table ES-2 shows the IRP-1 transmission system expansion implementation plan.

Table ES- 2: IRP-1 Transmission System Expansion Plan

Description	Year	Type	Voltage (kV)
Transmission Projects			
Old Harbour - Hunts Bay	2022	Expansion	138
Duhaney - Washington Blvd	2024	Re-conductor	69
Twickenham – Duhaney	2027	Re-conductor	69
Hunts Bay - Three Miles	2027	Re-conductor	69
New Transformer /BESS/VAR	**Year**	**Rating (MVA)**	**Qty.**
Hunts Bay 138kV	2022	80	1
Bulk Cap Bank	2024	6	1
Bulk Cap Bank	2024	5	1
BESS	2022	20	1
BESS	2024	20	1
BESS	2030-2037	100	5

Based on the lead times for the implementation of the transmission projects required to be in operation between 2022-2024, it is not now expected that these schedules will be met.

IRP-2 Preferred Portfolio Implementation Plan Highlights

IRP-2 considers the changes impacting the electricity sector since the development of IRP-1 and used extensive modeling and analyses to produce an updated preferred portfolio implementation plan to ensure that the IRP remains current and relevant, considering the pace of development in the electricity market, technologies, and government policies. The changes included:

1. The upgrading of the Renewable Portfolio Standard from 30% to 50% by 2030.
2. June 2020 update of the National Determined Contribution GHG emissions reduction from the 2005 levels.[3]
3. Updated load and energy forecasts.
4. Updated fuel price forecasts.
5. Updated JPS' plants retirement schedules.
6. Updated technological developments and pricing of solar, wind and battery energy storage technologies.[4]

Major changes since the promulgation of IRP-1 are shown in Table ES-3 and ES-6, which also gives the summary comparison between IRP-1 and IRP-2 preferred implementation plans. The updated IRP-2 preferred portfolio plan is provided in Table ES-4.

[3] June 2020 Update of Nationally Determined Contribution (NDC) of Jamaica to the United Nations Framework Convention on Climate Change
[4] *2022 Electricity Annual Technology Baseline*.: National Renewable Energy Laboratory.

Table ES- 3: Major Changes Since IRP-1 Development

- Renewable Portfolio Standard (RPS) increased from 30 percent in 2030 to 50 percent in 2030.
- Jamaica's climate change targets for GHG emission reductions have changed significantly in the June 2020 Update of Nationally Determined Contribution (NDC) of Jamaica. By 2030, planned emission reductions relative to a business-as-usual scenario (which takes into account policies in place as of 2005) from the electricity and the energy sector would be 1.8 to 2.0 MtCO2e lower than they otherwise be, compared with a range of 1.1 to 1.5 MtCO2e in its previous NDC.
- The lock down measures instituted by the GoJ to arrest the spread of the Covid-19 pandemic resulted in significant contraction in economic and social activities resulting in reduced forecasted electricity demand over the planning period relative to the IRP-1 forecast with demand being reduced from 1.48% CAGR to 0.6% CAGR over the 20-year planning periods.
- The Minister's Retirement Schedule for JPS owned generating plants has been extended from 2023 to 2026 for the retirement of 171.5 MW of plant capacity.
- JPS was awarded in April 2022 the ROFR right to install the 171.5 MW of replacement plant capacity by 2027. This development was not factored into the IRP-1.

IRP-2 Generation Preferred Portfolio Implementation Plan

The updated IRP-2 identifies the resource requirements and presents a pathway for the Jamaican electricity sector to achieve an integration of at least 50% of generation energy requirements from renewable energy sources by 2030. The study has established the timing, technologies, size of plant, fuel requirements and transmission system infrastructure, that are to be installed to reliably meet the projected load demand within the established reliability level. The required investment costs, operations and maintenance costs are computed and provided over the study period 2022-2041. Table ES-4 shows IRP-2 preferred portfolio highlights.

IRP-2 is based on the best latest information known and available to MSETT at the time of the update as at 2022 October. This update document IRP-2 is to be read in conjunction with the IRP-1 document.

Table ES- 4: IRP-2 Preferred Portfolio Highlights 2022-2041

Procurement of:

- 344 MW of wind plants comprising of 201 MW of plants between 2025 to 2030, 143 MW between 2031 to 2041.
- 34.3 MW of hydro power plant capacity, comprising of 12 small hydro plants across the country installed between 2027 to 2033.
- 1143 MW of solar PV plants comprising of 540 MW between 2025-2030 and 604 MW between 2031 to 2041.
- 493 MW of 2-hour battery energy storage systems (BESS) with 264 MW between 2024 -2027, 229 MW between 2033 to 2037.

Retirement of:

- 60 MW, 124 MW of IPP Diesel plants in 2024, and 2026 respectively
- 131.5 MW of combustion turbines and 40 MW JPS diesel plants in 2027
- 65.5 MW of IPP diesel plant in 2033
- 3 MW, 38 MW and 60.3 MW of wind plants in 2029,2032 and 2037 respectively.
- 20 MW of solar plant in 2037.

Achievement of:

50% renewable energy portfolio standard by 2030.

Reduction of:

- BOE imported for electricity sector from 5.97 million BOE in 2022 to 3.75 million BOE in 2030, reduction of approximately 2.21 million BOE per annum.
- Reduction in GHG gas emissions from 2.15 million tonnes in 2022 to 1.29 million tonnes by 2030 or an average reduction of 0.861 million tonnes per annum. A total reduction of 17.5 million tonnes of GHG emissions over the planning period.

To maintain the schedule of resource implementation to achieve the 50% RPS by 2030, the procuring entity needs to carry out the next procurement of renewable energy plants between 2023-2024 for the plants to be in operation by 2025-2027. Table ES-5 shows the summary of scenario A and scenario B generation expansion implementation plans. Figure ES-1 shows the Energy mix evolution for the preferred implementation plan.

Figure ES- 1: Energy Mix Evolution

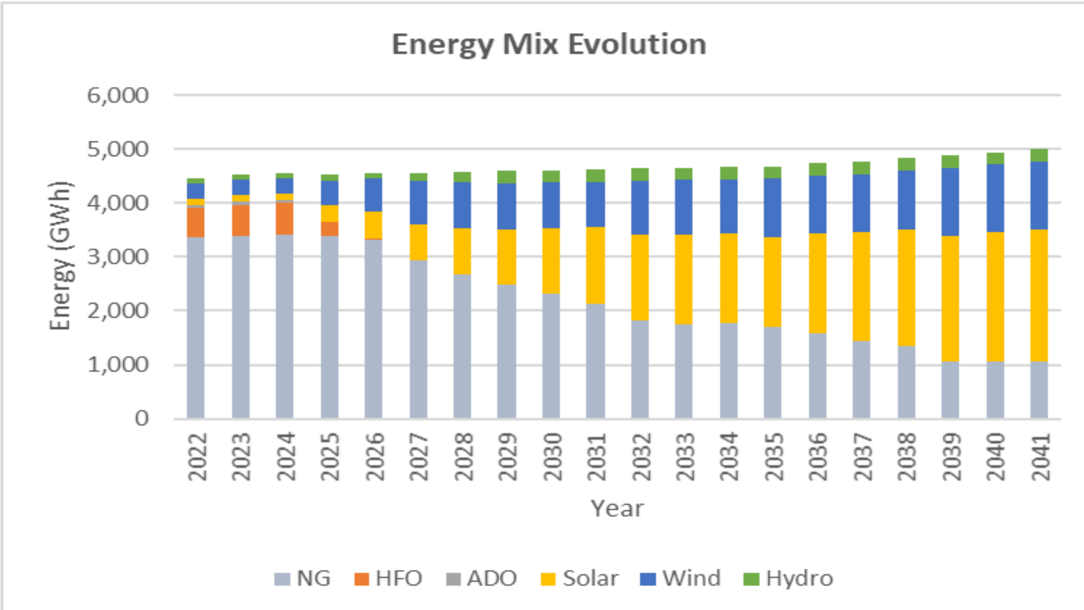


Table ES- 5: Generation Expansion Scenarios Summary Results

Ref load & fuel price forecasts	**A**	**B**		
Renewable Portfolio Standard of 50%	**42% RE**	**Preferred Portfolio**	**Impact**	**Impact %**
PV Generating System Total Costs (US$'000')	5,920,809	5,922,243	1,435	0.02%
PV Fuel Costs (US$'000')	2,679,719	2,559,680	-120,038	-4.69%
PV Thermal Variable O&M Costs (US$'000)	29,499	28,102	-1,397	-4.97%
PV Build Cost (US$'000)	1,202,368	1,303,600	101,232	7.77%
PV Fixed O&M Costs (US$'000)	658,512	673,787	15,275	2.27%
Barrels of Oil Equivalent Consumed (BOE)	77,067,559	72,274,933	-4,792,626	-6.63%
CO2 Emissions (Tonnes)	26,333,876	24,801,157	-1,532,720	-6.18%
New Capacity Installed (MW)	2,003	2,113	110	5.21%
Firm Capacity Installed (MW)	874	874	0	0.00%
Renewable Capacity Installed	1,510	1,620	110	6.79%
BESS Capacity (MW)	493	493	0	0.00%
System LCOE (US$/kWh	112.83	110.19	-3	-2.40%
Renewable Energy Percent on generation	42.00%	49.80%	0.08	15.66%

Figure ES-2 shows the generating system supply and demand balance throughout the 20-year planning period. It is noted that the plan meets the required minimum reserve margin of at least 20% of firm capacity more than the peak demand to ensure reliable supply of electricity to consumers. Figure ES-3 highlights the technology mix component of the generating system capacity.

Figure ES- 2: IRP-2 Demand, Supply & Reserves

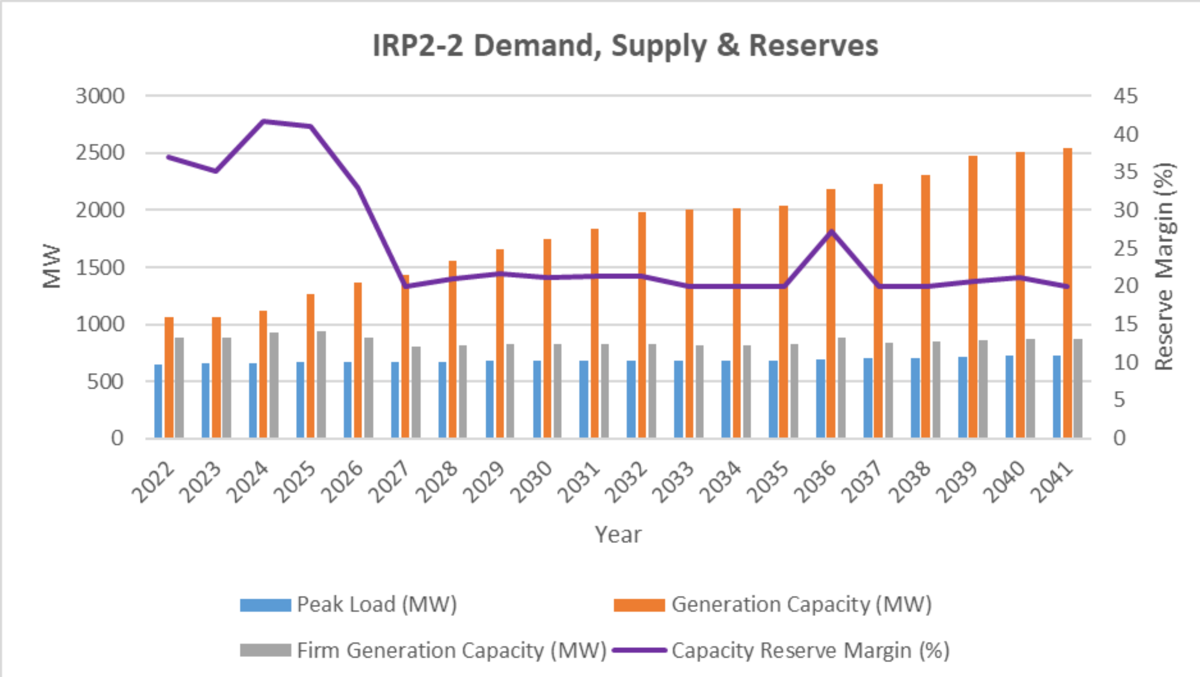


Figure ES- 3: Installed Capacity by Technology

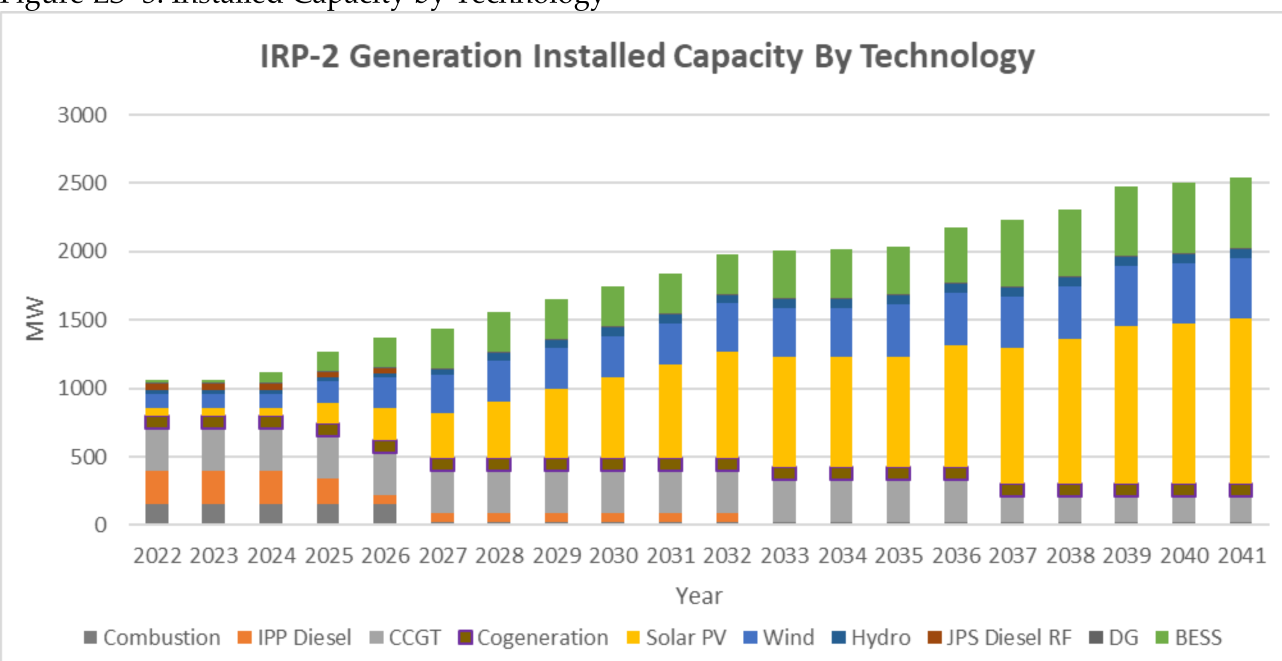


Table ES-6 shows the preferred implementation plan summary schedule.

Table ES- 6: Capacity Implementation Summary

Generation Preferred Implemenation Schedule				
Schedule	Wind	Hydro	Solar	BESS
	MW	MW	MW	MW
2023-2025	60	0	90	114
2026-2030	141	31.12	450	150
2031-2035	82	3.18	214	64
2036-2041	61	0	390	164
Total	**344**	**34**	**1143**	**493**

The implementation plan requires that wind, solar and battery energy storage systems are the dominant generating resources.

IRP-2 Transmission Plan

The revised 2030 RPS target of 50% coupled with VRE and BESS technology advancement and cost reductions are creating opportunities for Jamaica to lessen its dependence on imported fossil fuel, meeting its GHG target while reducing the costs of electricity to customers. The transmission grid impact assessment is primarily focused on addressing the increase in VRE from 12.5% to 50% by 2030 and the integration of 493 MW of BESS energy capacity over the 20-years planning horizon. This involves the review of transient, dynamic and steady state response to various critical operating conditions for the forecasted loads, power interchange, outage contingency conditions and generation economic load dispatching.

In summary the following observation and recommendations are made:

1. Normal and abnormal conditions are adequately addressed with upgrade of specific existing transmission lines, substations and the construction of new transmission lines.

2. The synthetic inertia of the preferred portfolio BESS is adequate to mitigate against the threat of grid instability with the reduction in system inertia due to the

displacement of thermal generation with VREs that affect the rate of change of system frequency during disturbances.

3. The Analysis recommends the need for a new transmission corridor from Old Harbour into the Corporate Area. It further concludes that an Old Harbour – Three Miles 138 kV line would be more beneficial to customers than the alternative Old Harbour - Hunt's Bay 138kV line.

4. Based on the results of the critical fault clearing times and short circuit analyses, with the integration of more VREs and BESS there will be a need to relook the protection coordination scheme system wide.

Tables ES-7 shows the summary comparison between the IRP-1 and IRP-2 key elements.

Table ES- 7: IRP-1 and IRP-2 Summary Comparison

	IRP1	IRP 2	Change	Comments
Parameters/Assumptions				
Planning Period	**2018-2037**	**2022-2041**		10 year period IRP-2 focus on achieving the updated RPS, resource implementation , PPA expiry, retirement schedules
IRP Reports	First IRP developed by MSETT. Stand alone	Not stand alone. To be read in conjunction with IRP-1		
Power Market Forecast				
Peak Demand Forecast (MW)	798 MW by 2030	678 MW by 2030	120 MW reduction	IRP-1 forecast demand did not materialized
Demand Growth Rate (CAGR)	1.48%	0.70%	50% Reduction	Major Impact on capacity expansion
Retirement				
JPS Existing Plant Retirement (MW)	114.0	285.5	171.5 MW	Based on Minister's revised schedule
IPP Diesel Plant Retirement (MW)	249.9	249.9	None	IRP-2 based on PPA expiration date
RE Plant Retirement (MW)	80.3	101.3	21 MW increase	IRP-2 Based on PPA expiration date
Fuel Price Forecast				
Natural Gas (CAGR)		2.7%		Moderate impact due to higher level of renewable
Fuel Oil (CAGR)		-0.1%		Low impact due to lower use of HFO
Diesel Oil (CAGR)		0.45%		Low impact due to low use.
Economic Parameters				
Base Year	2018	2021		
WACC (Post Tax)	7.44%	7.91%	6.3% reduction	Low Impact

Cost of unserved energy($/MWh)	3500 (2017$)	4266 (2021$)	No real change	No impact
Reliability				
LOLP	0.55%	0.55%	No change	No change
Minimum Reserve Margin	20%	20%	No change	No change
Legislative, Regulatory Policy Changes				
RPS Target (RE percent of generation)	30% by 2030	50% by 2030	66% increase	Major impact
Update June 2020 (NDC) emission goals relative to 2005 for the electricity generation and energy use sectors.	1.1 to 1.5 reduction of MtCO2 by 2030	1.8 to 2.0 reduction of MtCO2e by 2030	>60% reduction of GHG emissions relative to base	Major impact. IRP-2 forecast reduction of 0. 954 MtCO2 reduction for the electricity sector by 2030.
Preferred Portfolio Plan				
RE Capacity Implementation Plan	**IRP-1**	**IRP-2**		
New Solar Installation (MW)	1130	1143	13 MW	13 MW increase in solar plant
New Wind Plant Installation (MW)	121	343	222 MW	222 MW increase in wind plants
New Hydro Plant Installation (MW)	34.3	34.3	No capacity	Implementation date change
Waste to Energy (MW)	18.0	0.0	Not selected	Low Impact-not a competitive option
Biomass (MW)	20.0	0.0	Not selected	Low impact- not a competitive option
BESS (MW)	0.0	493.0	493 MW	Allow for more renewable integration
Cost of Generation				
Avoided cost of generation (c/kWh)	10.29 (2018 $), 12.93 (2021$)	11.56 (2021$)	10.6% reduction in real terms	
Levelized Cost of Generation (USc/kWh)	15.14 (2021$)	11.02 (2021$)	27.2% reduction	
RPS Target Achievement				
RE penetration achieved in plan		49.8%	31%	RPS targets achieved as per RPS plans

Key Findings of IRP-1 Update

Table ES- 8 Key IRP Findings

1. Significant changes in the global and local landscapes since the development of the 2018 IRP impacting the local electricity sector have made it imperative for MSETT to update the 2018 IRP based of the magnitude of the changes to the electricity market, technology developments and renewable procurement standards and emissions reduction upgrade. 2. The IRP-1 preferred portfolio implementation plan schedule is no longer feasible given that the procurement lead times for new plants and the low pace of procurement initiatives. 3. The load growth forecasted in IRP-1 did not materialize, and the recent load forecast projects a 120 MW reduction in peak demand relative to IRP-1 forecast. 4. The costs of renewable energy and storage technologies are trending down making future investments in renewable energy technologies more feasible. 5. Fuel prices are expected to show frequent fluctuations over short periods but long term trends are expected to be relatively stable. 6. Fuel price fluctuations will be less impactful on electricity prices based on the higher levels of renewable resources. 7. The least cost expansion option (Preferred Implementation Plan) is the expansion plan which assumes that the JPS ROFR plants are replaced by renewable capacity coupled with BESS. 8. The preferred implementation plan (least cost) will require the installation 1,522 MW of clean renewable power comprising of 344 MW of wind plants, 1,143 MW of solar PV plants, 34.3 MW of hydro plants over the 20 -year planning period. 493 MW of battery energy storage systems (BESS) will be required over the planning period 2022-2041 to successfully integrate this level of RE resources. 9. BESS will play an important role to ensure system reliability, provide operational flexibility and minimize the extent of dump energy from renewable energy sources. 10. No new fossil fueled plant was selected as part of the preferred portfolio implementation plan. 11. Significant investments in renewable resources and BESS are required to achieve the 50% renewable portfolio standard and beyond. It is estimated that investments of US$1.3 Billion over the 20-years period, of which US$ 836 Million is required by 2030. 12. Beyond 2030 renewable energy sources will be the dominant source of electricity generation in Jamaica, with natural gas as the only fossil fuel energy source of note. 13. Renewable energy will contribute 49.8% of the energy generated by 2030 thus achieving the RPS target of 50% by 2030. 14. A lower than 50% of RE will result in higher system operating costs, higher generation cost per kWh, higher GHG emission and higher imported fossil fuel.

15. Repowering of contract expired wind turbines of over 20-year-old technology with new larger modern turbines is a viable option and can increase the capacity of such facilities by 3-4 times, with much improved performance and maximizing the use of valuable proven wind sites. The impact is a lower cost of energy from this method than from unproven greenfield sites.
16. Significant benefits will accrue from the investment in renewable energy investment will include:
17. Reduction of GHG emissions from approximately 2.1 million tonnes per annum in 2022 to 1.3 million tonnes in 2030.
18. Reduction in fuel imports from 5.7 million BOE in 2022 to 3.6 million per annum BOE in 2030 resulting in significantly less electricity price fluctuations.
19. IRP-2 implementation plan if implemented according to the planned schedule will achieve reductions in the cost of electricity generation and GHG emissions.
20. The preferred portfolio plan is robust to reasonable changes in key parameters.
21. It is critical to ensure that the implementation schedule milestones are maintained to achieve the stated objectives. In this regard the resource procurement process must be streamlined to allow for expeditious procurement, by developing the institutional capability to manage frequent and multiple resource procurements.
22. **Transmission Plan**
23. A major shift from the application of BESS as frequency regulation to several ancillary services (dispatch-able, virtual transmission line, capacity reserve, contingency spinning).
24. The application of 2-4 hours BESS versus 45 minutes BESS currently installed at JPS Hunts Bay S/S.
25. The advancement and price reduction in BESS technology have made significant gains in providing opportunities for power grids to satisfy varying operating and planning requirements for increasing RPS.
26. With over 493MW of BESS planned over the 20 years' horizon the price of ESS continues to fall coupled with longer storage duration. The price of BESS is projected to reduce by over 50% by 2030. BESS is therefore shaping to be the transitional technology to reduce Jamaica's dependence on imported fossil fuel.
27. The applications of BESS technology are not site specific and therefore lends itself to several solutions on the transmission and distribution grid to mitigate existing and anticipated violations.

Recommendations

It is recommended that the preferred implementation plan of IRP-2 and shown in Table ES-4 be adopted to guide the future development of the Jamaican electricity system. Timely updates of the IRP planning be carried out to take into account changes in key drivers impacting on the electricity sector.

Given the procurement timelines for new generating plant resources it is recommended that the procurement of resources required to be in operation by 2024 - 26 be started by 2023, and for resources required to be in operation by 2026- 2028 be started by 2024, and those resources required to operate by 2028 -2030 be started by 2026. In this regard we recommend that the resource procurement process be updated and streamlined as a matter of extreme urgency to allow for expeditious procurement of generating capacity. The institutional capability of the generation procuring entity be developed accordingly to manage the frequent and multiple resource procurements that are required.

Planning Updates and Feasibility Studies.

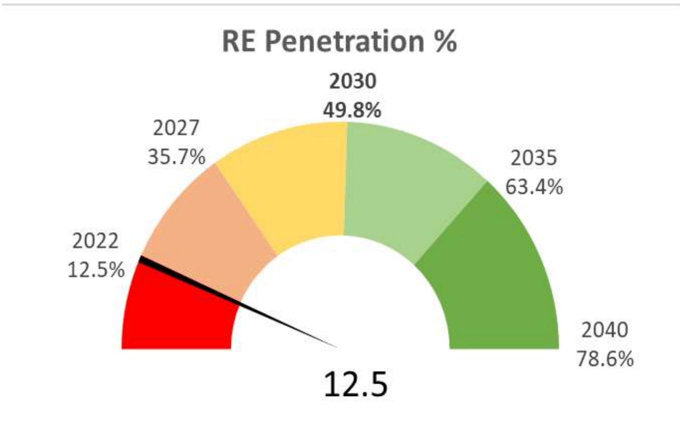
It is recommended that:

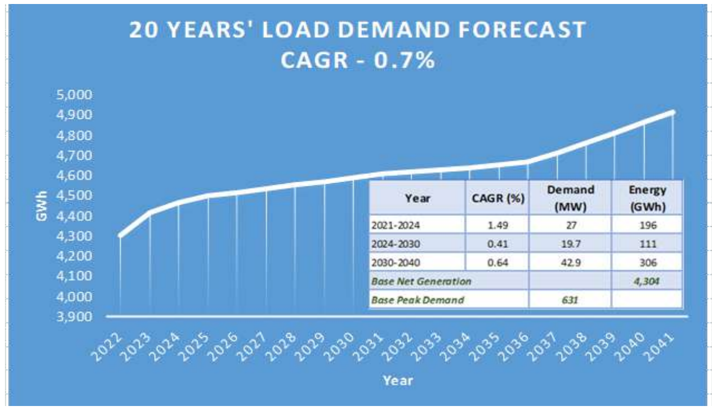
- The IRP study be updated at least on an annual basis, and a new IRP study carried out every other year given the uncertainties over the 20 -year planning period and the changes which can and will occur in energy demand forecasts, legislative and regulatory requirements, fuel pricing and technology changes.
- MSETT to develop and rank on technical and economic bases an inventory of suitable sites based on feasibility studies for wind, hydro and solar plant locations, considering the need to have geographical diversity of sites to ensure better renewable energy security, and not too dependent on one geographic location as is the situation today where the wind and solar renewables are predominantly located in the south of the island.
- In order to support the electricity planning function of MSETT and to ensure the harmonized, efficient and secured collaboration of the key sector stakeholders, the suite of existing electricity planning software and models are to be integrated by

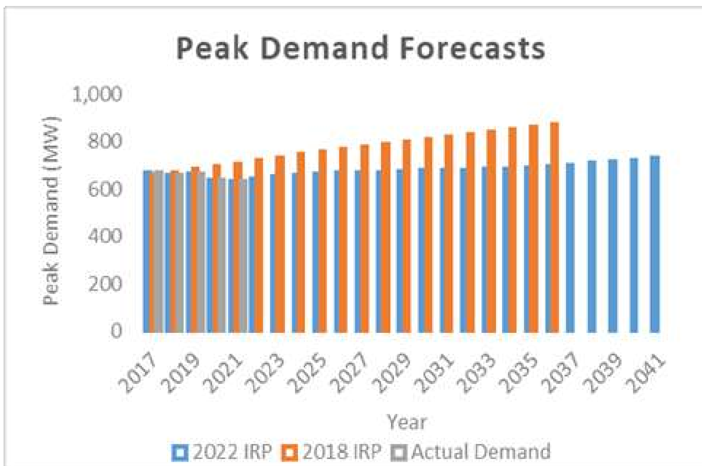
establishing a MSETT's ICT system/platform. This initiative should be developed and executed as a priority short term action.

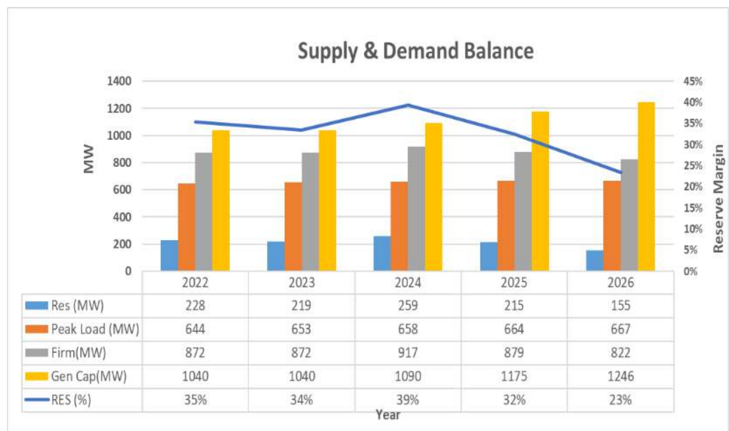
- MSETT resource capabilities be developed to keep abreast of renewable energy technologies developments and advances in energy storage technologies, in terms of alternatives, performance, availability and costs. These technologies should include; off-shore wind sites, floating solar plants technology and siting capabilities, hydrogen fuel cell, BESS and small scale nuclear power plant technology, as well as other emerging technologies for energy generation and storage.
- MSETT carry out technical and economic feasibility studies to determine the technical and economic feasibility of repowering of existing proven wind and solar resource sites.
- MSETT to keep abreast of local biomass and waste to energy potential by carrying out technical and economic feasibility studies to enable the development of these projects for market consideration.
- JPS updates the transmission and generation system data base to support the accurate modelling of these systems for power flow, and stability analyses of the power system.
- The OUR update of the Electricity Sector Codes to ensure that the provisions are relevant to the evolving renewable and energy storage technologies, and grid performance requirements.

IRP-2 Dashboard

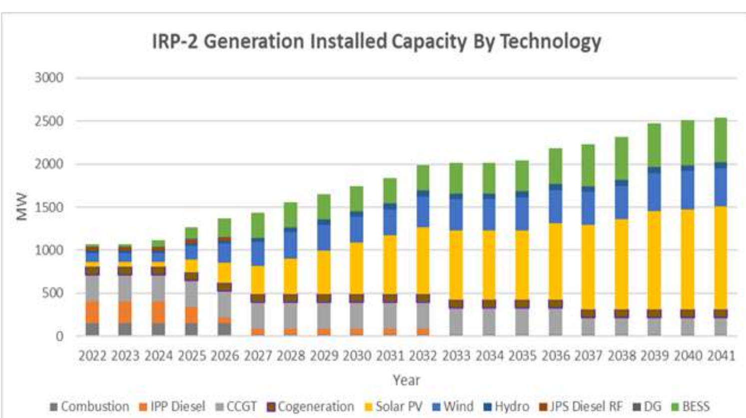






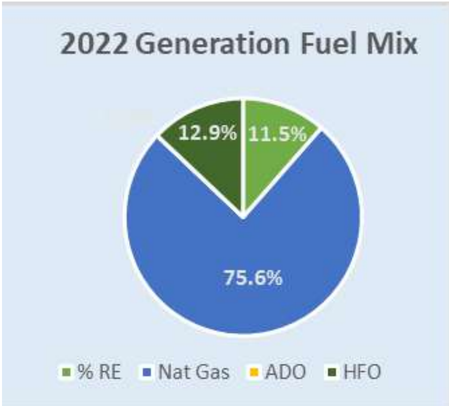


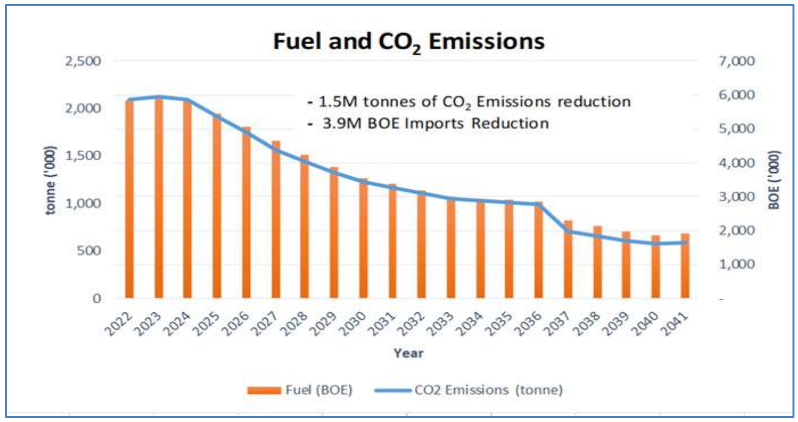
IRP Preferred Implementation Plan

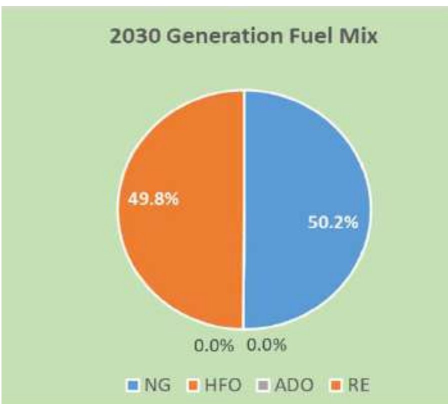


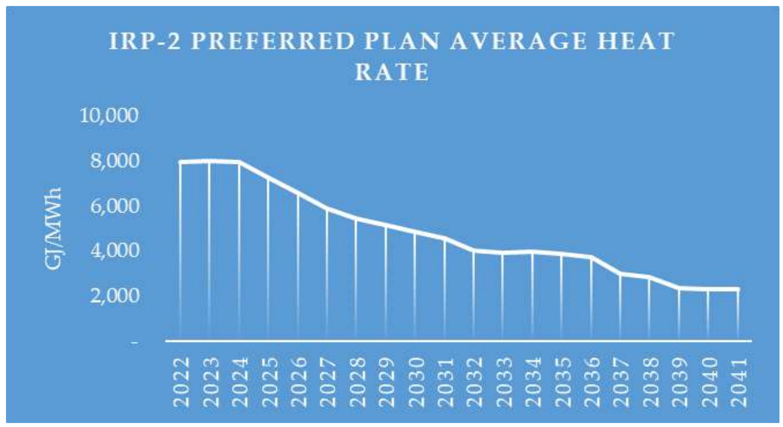
Generation Preferred Implementation Schedule				
Schedule	Wind	Hydro	Solar	BESS
	MW	MW	MW	MW
2023-2025	60	0	90	114
2026-2030	141	31.12	450	150
2031-2035	82	3.18	214	64
2036-2041	61	0	390	164
Total	344	34	1143	493

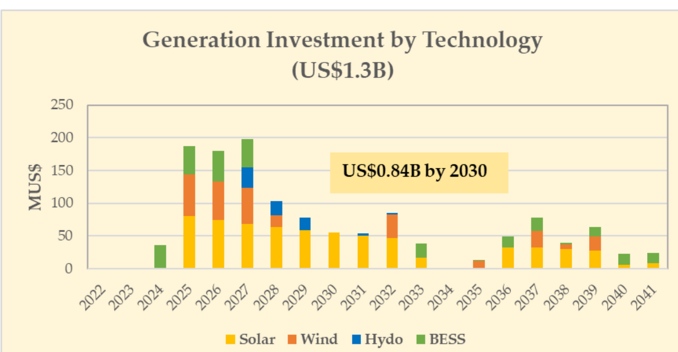
IRP-2 Plan Achieves RPS target of 50% by 2030

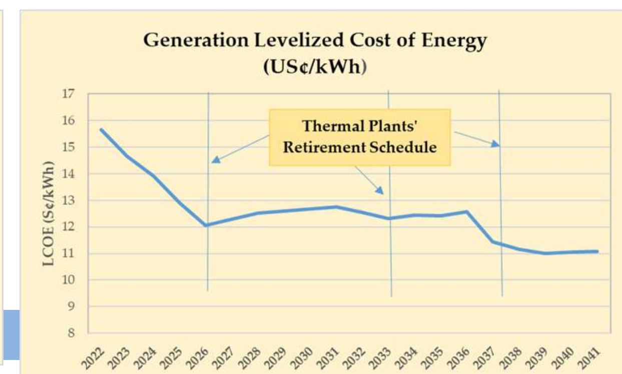












Generation Avoided Cost			
Total (¢/kWh)	Thermal Var. Costs (US¢/kWh)	RE (US¢/kWh)	Capacity($/kW-Month
11.56	11.73	6.69	10.56

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1. Background and Objectives

The Jamaican electricity sector 2018 integrated resource plan (IRP-1) was developed by MSETT, in accordance with the provisions of section 7 of the Electricity Act (EA) and in collaboration with sector stakeholders. The IRP-1 document was published in 2020 September.

Since the publishing of the IRP-1 report significant changes in the global and local landscapes impacting the local electricity sector have made it imperative for MSETT to update the 2018 IRP based of the magnitude of the changes to the electricity market, fuel prices and availability, technology developments, the renewable portfolio standard(RPS) and the upgrading of the National Determined contribution (NDC) to GHG emissions reduction targets.

The purpose of this update to IRP-1 is to develop a new preferred portfolio plan to take into account the changes in the power market load forecast, the upgrade of the renewable portfolio standard, the new GHG reduction targets, changes in plant retirement schedule, and resource pricing changes. The IRP-2 update report provides the new preferred portfolio implementation plan and details the impacts on costs and system reliability performance of the changes occurring since the publication of IRP-1.

The update of IRP-1 focused on two scenarios to determine the preferred portfolio implementation plan. The scenarios considered; (A) JPS 171.5 MW replacement capacity under ROFR provisions as a committed replacement for like thermal capacity, and (B) an unconstrained expansion sequence to determine the least cost capacity mix.

2. IRP-1 Preferred Portfolio Implementation Plan Review

2.1 IRP-1 Generating Resource Additions and Retirements

The IRP-1 preferred portfolio implementation plan provides the combination of supply and demand side resources and their implementation schedules to achieve the least cost, least risk transition to a sustainable and cleaner energy future. The main highlights of IRP-1 portfolio plan are shown in Table 2.1.

Table 2-1: IRP-1Preferred Portfolio Plan Highlights

Procurement of: • 34.3 MW of run of river hydro plants comprising of 12 small hydro plants sited throughout the country in 2023. • 1,130 MW of new solar PV plant resources, comprising 107 MW in 2022, 107.5 MW in 2024, 77 MW in 2027and the balance of 839 MW between 2032-2037. • 121 MW of new wind resources, comprising 40 MW in 2022, 47 MW in 2024 and 34 MW in 2027. • 18 MW of waste to energy (WTE) plants and 20 MW of biomass plants in 2023. • A total of 338.5 thermal natural gas fired candidate plants were also added over the period 2024 -2036.

IRP-1 preferred portfolio requires that 613 MW of existing generating plants be retired. These are shown in Table 2-2.

Table 2-2: Retirement Schedule IRP-1 preferred Portfolio

• The retirement of 20 MW of solar PV plant in 2037. • The retirement of 3 MW, 38 MW and 60.3 MW of wind plants on expiry of their contracts in 2029, 2032, and 2037 respectively. • The retirement of 262 MW of JPS steam plants previously earmarked for retirement in 2020. • The retirement 114 MW of JPS Bogue combined cycle plant in 2037. • The retirement of 249.9 MW of IPP diesel plants comprising of 60 MW in 2025, 124.5 MW in 2026 and 65.5 MW in 2033 based on their scheduled contract expiry dates.

2.2 IRP-1 Transmission System Implementation Plan

Transmission plans for the preferred generation expansion sequences were developed based on the siting of the new generation resources identified in the generation preferred implementation plan. The results of the load forecast, the least cost transmission plan determined the best location of bulk step down substations, and developed several transmission resource alternatives to interconnect the generating plants to the load areas. Section 3.7 of the IRP-1 report details the transmission system planning process.

Table 2-3 shows the Transmission system preferred implementation plan.

Table 2-3: IRP-1 Transmission Expansion Plan

Description	Year	Type	Voltage
Transmission Projects			
Old Harbour - Hunts Bay	2022	Expansion	138
Duhaney - Washington Blvd	2024	Re-conductor	69
Twickenham – Duhaney	2027	Re-conductor	69
Hunts Bay - Three Miles	2027	Re-conductor	69
New Transformer /BESS/VAR	**Year**	**Rating (MVA)**	**Qty.**
Hunts Bay 138kV	2022	80	1
Bulk Cap Bank	2024	6	1
Bulk Cap Bank	2024	5	1
BESS	2022	20	1
BESS	2024	20	1
BESS	2030-	100	5

2.3 Generating Resources Procurement

To meet the IRP objectives, the generating resources identified by IRP-1 for installation between 2022 and 2024, the procurement would need to have been started by latest 2021, given the lead times required for the procurement to commercial operations of the new plants. As of June 2022, the procurement of these resources has not commenced, and it is no longer realistic to expect that any of the plants identified will be procured and installed within the required schedule. No tangible actions have started to expedite the procurement of resources required to meet the schedule and consequently the stated objectives of IRP-1. Regarding the lead times for the implementation of the transmission projects required to be in operation between 2022-2024 it is also not expected that these schedules will be met.

3. What has Changed since IRP-1 Development?

Since the start of the development and the publication of the 2018 IRP (IRP-1) report several significant events have occurred in the global and local landscapes. These events, which included inter alia the Covid-19 pandemic and the Russian-Ukraine conflict have had a profound impact on the global and local economies, and consequently the demand for electricity. In addition to these events, the accelerated drive towards carbon neutral energy generation to assist in combating the effect of climate change has made it imperative to update 2018 IRP to ensure that the plan remains relevant and current. Given the magnitude of the changes that have occurred, the initial IRP-1 preferred portfolio plan is no longer representative of the requirements to meet the stated objectives of the electricity sector.

The major changes not anticipated in IRP-1 are detailed in Table 3-1.

Table 3-1: Major Changes Not Anticipated in IRP-1

- GoJ has upgraded the Renewable Portfolio Standard (RPS) from 30 percent in 2030 to 50 percent in 2030. The result is that the IRP-1 portfolio plan does not satisfy this new RPS mandate.
- Jamaica's climate change targets for GHG emission reductions have changed significantly in the June 2020 Update of Nationally Determined Contribution of Jamaica. By 2030, it foresees emission reductions relative to a business-as-usual scenario (which considers policies in place as of 2005). This mandates that emissions in the electricity and the energy sector would be 1.8 to 2.0 MtCO2e lower than they otherwise be, compared with a range of 1.1 to 1.5 MtCO2e in its previous NDC.
- The impact of the lock down measures instituted by the GoJ to arrest the spread of the Covid-19 pandemic. The measures have resulted in significant reduction in economic and social activities in the country and consequently the electricity demand over the planning period. The forecasted demand for electricity has been reduced from 1.48% CAGR to 0.6% CAGR over the 20-year planning periods of 2018-2037 and 2022-2041 for IRP-1 and IRP-2 respectively.
- Significant short-term changes have been experienced in imported fuel prices, occasioned in part to supply disruptions due to the ongoing Ukraine and Russian conflict. While this

conflict persists uncertainties will continue to affect the price of fuel and other relevant supplies to the sector.

- None of the projects identified to be completed in the 2022–2024 time period to meet IRP-1 preferred portfolio schedule requirements have been started. Given the procurement and construction lead times these projects are not expected to meet their required commercial operation date (COD).
- The Minister's Retirement Schedule for JPS owned generating plants has been extended from 2023 to 2026 for the retirement of 171.5 MW of thermal plant capacity.
- JPS was awarded in April 2022 the ROFR right to install the 171.5 MW of replacement plant capacity by 2027. This development was not factored into the IRP-1.

In addition to the changes identified above, adjustments were made for IRP-2 to include:

- Technology and cost trends to reflect the improvement in technology availability, costs of generating candidate options.
- The impact of electro-mobility and energy efficiency measures on electricity demand projections.
- The natural gas infrastructure fixed costs which were inadvertently not considered in IRP-1 modelling analyses.

The 2022 update (IRP-2) has considered the above changes to develop an updated preferred portfolio implementation plan which is significantly different from the IRP-1 plan to satisfy the new requirements arising from the impacts of the changes identified.

4. Main Features of the updated IRP-2 Preferred Portfolio

4.1 IRP Development Process Overview

The process used to develop the 2018 IRP is summarized as : A) Developing forecasts of the Jamaican electricity sector future energy needs, (B) Assessment of the energy demand and supply balances, (C) Analyses of various alternative resources to meet identified shortfall in load and resource balances, (D) Determine the type, timing, and siting of these resources in the generation and transmission systems, and (E) Develop various portfolio scenarios and analyze the different portfolios to select the preferred portfolio in terms of the costs, risks , reliability, environmental impact, GoJ policies, and the flexibility to respond to changes to key assumptions.

The process applied to develop the 2018 IRP plan is well established in the electricity sector globally and utilizes internationally accepted planning methods and models. The details of the planning process and modelling are well documented in the 2018 IRP (section 1.2). This process was also followed to update the IRP-1 but also utilizes the best and latest information available at the time of the update, inclusive of changes impacting on the sector but not considered in IRP-1.

4.2 Key Assumptions, Parameters and Changes

4.2.1. Demand Forecast

The starting point of the update study is the demand forecast. The updated demand forecast encompasses the planning horizon of 2022-2041. The technique employed for the forecasting is based on econometric construct from which energy demand is derived from a set of socio-economic variables. The base forecast shows the compounded annual growth over the period 2021 -2041 is 0.7%, 1.49%, for the 2021-2024 period and 0.41% from 2024 -2030, 0.64% from 2030-2040 respectively. System load factor is 77.65% over the period.

The updated demand forecast was developed by JPS and accepted by MSETT for use in the update of IRP-1. The same methodology was applied as used in the 2018 IRP. Section 3.2 of the IRP-1 details the method used in developing the IRP-1 load forecast.

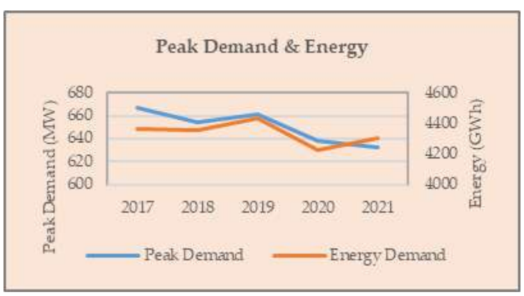
The base forecast for IRP-1 shows the compounded annual growth rate (CAGR) of electricity generation over the period 2017-2038 of 1.59%. System load factor was 78.0% over the period. The energy demand growth was projected to increase from 4489.5 GWh in 2018 to 5939.2 GWh in 2037 and the peak load demand from 667 MW to 869 MW for the most likely growth scenario. However, the impact of the lock down measures instituted by the GoJ to arrest the spread of the Covid-19 pandemic resulted in a reduction in electricity demand from pre-pandemic levels of peak load and energy demand of 667 MW and 4363 GWh per annum respectively in 2017 to a much reduced peak load and energy demand of 632 MW and 4304 GWh in 2021.

Based on the new forecast, peak demand is reduced by 8.4 % in 2022 relative to the pre-pandemic period, and by 2030 decreasing by 13.4% of the IRP-1 forecasted demand. The updated forecasted demand for electricity has been reduced from 1.48% CAGR to 0.6% CAGR over the respective 20-year planning periods. The peak demand forecasted for IRP-2 has moderately increased from 644 MW in 2022 to 678 MW in 2030, and 728 MW by 2040. Energy demand projection has increased from 4425 GWh in 2022 to 4688 GWh by 2030, and 5119 GWh in 2041. The projections are now that based on the load forecast utilized in the 2018 IRP relative to the current updated forecast, it is not expected that the electricity demand will recover to pre-pandemic level until 2025. This is a significant shift of approximately 100 MW in demand level which suggests that the updated preferred portfolio will require less generating capacity to supply this level of demand while maintaining the prescribed reliability level. The situation thus provides further opportunities to integrate more economic renewable energy projects in the generating system. The forecasted demand utilized for IRP-2 took into account the demand impact of the penetration of electric vehicles (EV) on the electricity system, and is estimated at 3% of energy demand by 2030 and, the reduction due to distributed generation of approximately 1%. Table 4-1 shows the forecasted energy and peak load demand forecasts for IRP-2.

Table 4-1: Energy and Peak Demand forecast IRP-2

	Expected growth scenario						
	Base Net	Base Net	Net	DG	EV	Expected	Peak
2021	4,304	4,304				4,304	631
2022	4,415	4,395	20	-	-	4,415	644
2023	4,466	4,416	50	(8.8)	8.42	4,466	653
2024	4,495	4,424	71	-12	17	4,500	658
2025	4,510	4,430	80	-21	25	4,515	664
2026	4,519	4,434	84	-30	48	4,537	667
2027	4,521	4,436	86	-39	71	4,553	669
2028	4,526	4,440	87	-48	93	4,572	670
2029	4,531	4,445	87	-57	116	4,590	675
2030	4,538	4,451	87	-66	139	4,610	678
2031	4,546	4,459	87	-76	149	4,619	679
2032	4,556	4,469	87	-85	159	4,629	679
2033	4,567	4,480	87	-95	169	4,641	682
2034	4,579	4,492	87	-105	179	4,653	684
2035	4,593	4,506	87	-115	189	4,667	686
2036	4,608	4,521	87	-125	232	4,715	691
2037	4,624	4,537	87	-135	275	4,764	700
2038	4,641	4,554	87	-146	318	4,814	708
2039	4,659	4,572	87	-156	361	4,864	715
2040	4,678	4,592	87	-166	404	4,916	721

Figure 4.1 shows the IRP 2018 and the 2022 updated demand forecasts.



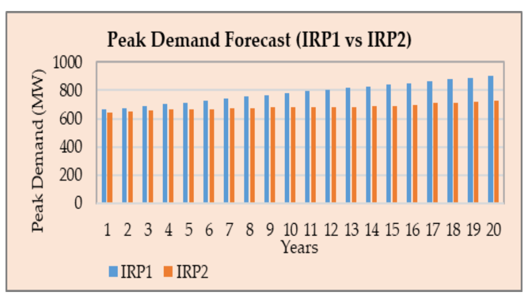


Figure 4.2:Actual Peak & Energy DemancFigure 4.1:Peak Demand Forecasts

4.3 Renewable Portfolio Standards

As of 2016 renewable energy sources contributed approximately 6.3 percent of net electricity generation to the JPS grid, and by 2020 with the completion of the procurement of 115 MW of renewable energy plants by 2019, renewable energy contribution to the generation mix increased to approximately 12.4 percent of net generation.

The IRP-1 preferred implementation plan promotes the transition to cleaner energy production and reduced utilization of imported fossil fuel by achieving a renewable energy penetration in the generating system of 31.5 percent in the generation mix by 2030.

According to IRP-1 schedule of new resource additions, the implementation plan, when fully executed to 2037 would result in renewable energy sources providing at least 30% percent of the generation required by 2030 and 49 percent at the end of the planning horizon in 2037. Solar PV plants would comprise of 1187.5 MW the largest share of renewable energy sources, natural gas fired plants will provide 51% of the electricity system energy needs.

Since the publishing of the IRP-1 plan, the GoJ has increased the RPS from 30% to 50% by 2030. This increase in the RPS implies that at least 50% of the system net generation is to be produced by renewable energy sources or 2344 GWh from renewable energy sources by 2030.

5. Existing Generating System

IRP-1 Provided a comprehensive description of the growth and evaluation of the status of electricity generating assets, which are detailed in section 3 of IRP-1. JPS, the system operator owns an installed generating capacity of 643.14 MW. IPP owned generating facilities contribute an additional capacity of 298.36 MW. The IPP facilities all operate under a 20-year power purchase contract which also includes conditional provisions for contract extension on expiry.

In 2019 the generating system installed firm capacity was 1011.4 MW to serve a peak load of 661 MW. In 2021 the installed firm capacity totaled 853 MW to serve a peak demand of 632 MW, due to the decline in demand.

Since the publishing of the IRP-1 in September 2020 the generating system has not changed relative to the assumptions included in the IRP-1 analyses. Projects which were committed at the start of the 2018 IRP plan have since been constructed and commissioned into service. These included; 194 MW of gas fired combined cycle plant in 2019, 94 MW of gas fired cogeneration plant at the alumina refinery in 2020, and 37.5 MW of solar plant in 2019. A total of 262 MW of JPS heavy fuel oil (HFO) burning steam units were retired in 2020 in accordance with the planned retirement schedule for JPS owned generating units.

To support the operations of the system with the increasing level of renewable energy integration JPS installed a 24.5 MW hybrid energy storage system (HESS) consisting of 20 MW Li-ion battery and 4.5 MW flywheel in 2019. The storage duration is rated at 40 minutes. This system can provide short term frequency and voltage regulation and is not considered a generation capacity resource. JPS has also completed the installation of 10 MW of the 14 MW granted for the replacement of the 14 MW Bogue gas turbine GT 8 plant under the ROFR provisions in 2021. Table 5-1 shows the generating system installed capacity from 2019-2021.

Table 5-1: Generating System Installed Capacity

Technology	2019	2020	2021
	MW	MW	MW
JPS Steam HFO	262.0	0.0	0
JPS Diesel HFO	40.0	40.0	40.0
Gas Turbines NG	20.0	20.0	20.0
Gas Turbines ADO	131.5	131.5	131.5
Comb. Cycle NG	114.0	114.0	114.0
Dist. Generation	0.0	0.0	10.0
JPS Thermal	567.5	305.5	315.5
IPPs Diesel HFO	249.9	249.9	249.9
IPPs NG	194.0	288.0	288.0
Total IPP Thermal	443.9	537.9	537.9
System Firm Capacity	1,011.4	843.4	853.4
JPS Hydro	28.7	28.7	28.7
IPP Solar	20.0	57.0	57.0
IPP Wind	101.3	101.3	101.3
Renewable Generation	187.0	187.0	187.0
Total Capacity	**1198.24**	**1030.34**	**1040.4**

5.1 Generating Resource Retirements

The Minister's Retirement Schedule for JPS owned generating units has been extended from 2023 to 2026. As a result of this extension, JPS was awarded the rights to replace 171.5 MW of generating plants to be retired in 2026 under the Electricity Act ROFR provisions. Table 5-2 details the Minister's retirement schedule.

Table 5-2: Minister's Retirement Schedule for JPS Units

Unit	Location	Capacity (MW)	Existing Retirement Date	New Retirement Date
Rockfort Unit 1	Rockfort, Kingston	20.0	2023	2026
Rockfort Unit 2	Rockfort, Kingston	20.0	2023	2026
GT 5	Hunts Bay, Kingston	20.0	2023	2026
GT 10	Hunts Bay, Kingston	32.5	2023	2026
GT 3	Bogue, Montego Bay	21.5	2023	2026
GT 6	Bogue, Montego Bay	18.0	2023	2026
GT 7	Bogue, Montego Bay	18.0	2023	2026
GT 9	Bogue, Montego Bay	20.0	2023	2026
Total Capacity Retired		171.5		

Source: MSETT

5.2 Independent Power Producer Contracts

The Independent Power Producers supply capacity and energy to JPS under the terms of power purchase agreements (PPAs), which have a 20 year-duration. However, the PPAs include term extension provisions and can be extended based on terms agreed between the IPP and JPS, with approval from the OUR. Table 5-3 shows the existing IPP PPA expiration dates.

Table 5-3:PPA Expiry Dates

	2024 MW	2025 MW	2026 MW	2027 MW	2029 MW	2031 MW	2032 MW	2033 MW	2037 MW	2038 MW
IPP Diesel	60.0	-	124.5	-	-	-	65.5	-	-	-
IPP Wind	20.0	-	-	-	3.0	-	-	-	60.3	18.0
IPP Solar		-	-	-	-	-	-	-	-	20.0

*Generating plants retirements are effective at the end of the year stated.

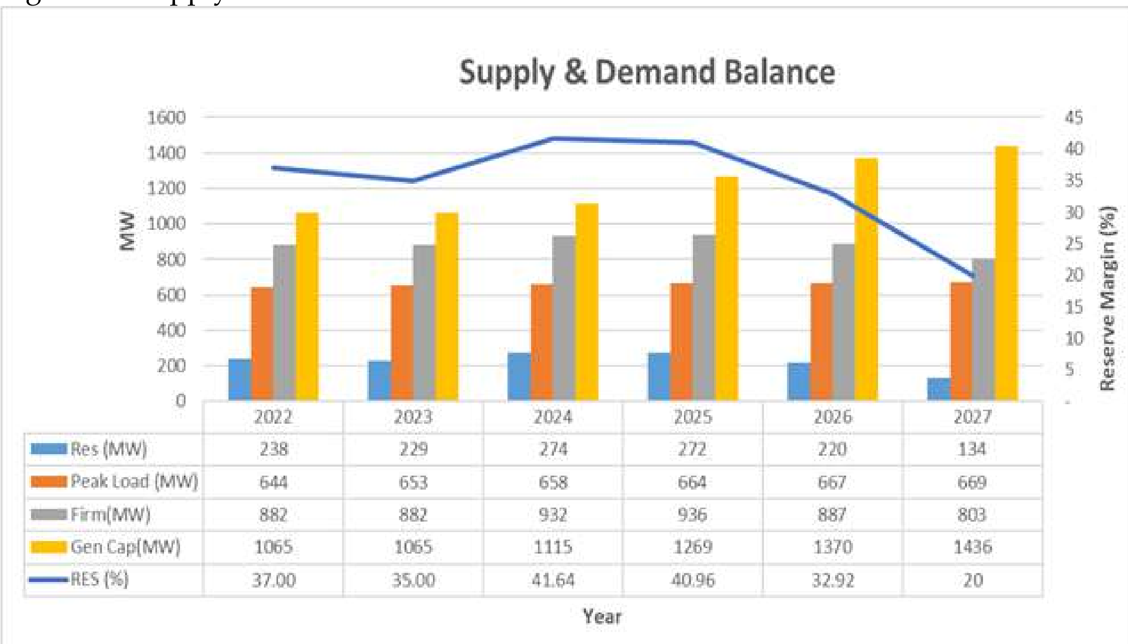
Depending on the technology, the useful economic life of the plant may extend beyond the initial contract term, based on the operation and maintenance regime as manifested in their performance and guided by projections, the unit could however be reintroduced to the system for a shorter contract period at a percentage of its fixed cost since the initial capital investment would have been fully recovered by the IPP.

5.3 Generating System Supply and Demand Balance

In 2021 the generating system installed capacity including JPS owned plant and the independent power producers connected to the grid comprise of 853 MW of firm capacity and 187 MW of wind and solar renewable non-firm capacity. The generating plants served a peak demand of 632 MW in 2021, resulting in a reserve margin of 209 MW or 33 % to provide maintenance space for planned and forced outages of generating units. Figure 4 highlights the supply and demand balance up until 2027, after the retirement of the 60 MW of IPP diesel plant in 2025 and an additional retirement of 124 MW in 2026. The reduction in the peak demand due to the economic contraction resulting from the

Covid-19 containment measures and the slow pace of recovery of demand, it is anticipated that sufficient generating reserve margin of 33 percent will be sufficient to meet system peak demand and accommodate required plant maintenance activities until 2026.

Figure 5.1:Supply and Demand Balance



6. Generating System Expansion Options

6.1 Candidate Plants

Candidate plants for expansion options were selected from a mix of proven technology generation options based on a screening process. Table 6-1 shows the plant types considered as expansion candidates. Section 3.6.1 of IRP-1 described the selection process of candidate plants used in the mix to determine the preferred implementation plan. IRP-2 utilize the process used in IRP-1 to screen candidate plants to go forward to the analyses to develop the preferred portfolio.

The review of Waste to Energy and Advanced Nuclear (Small Modular Reactor) were found to be cost prohibited relative to the generating plant candidate resources.

Table 6-1: Generating Plant Candidate Resources

1. Candidate Generation Resources
2. Simple cycle combustion turbines
3. Combined cycle combustion turbines
4. Medium speed diesels
5. Small diesels for distributed generation application
6. Utility scale solar PV plants
7. Utility scale wind plants
8. Biomass plants
9. Waste to energy plants
10. Wind Energy plants
11. Solar PV plants
12. Battery energy storage systems
13. Advanced Nuclear – Small Modular Reactor

6.2 Committed Capacity Projects

A project is considered committed when the project has been awarded by the procurement body and there is an executed power purchase agreement (PPA) or negotiations are substantially advanced with all the main conditions and key project security agreements in place leading to PPA execution. JPS projects are also considered committed when the projects are awarded to JPS under the provisions of the ROFR and the Letter of Notification has been issued by MSETT to JPS outlining the terms and conditions of the ROFR. JPS was awarded the rights to replace 171.5 MW of thermal generating plants to be retired in 2026 under the ROFR provisions.

7. Economic and Technical Operating Parameters.

The development of the IRP-1 and the update IRP-2 generation and transmission plans are based on established economic criteria, reliability constraints, technical interconnection and operation guidelines. These criteria and guidelines are based on the regulatory guidelines for development and interconnecting power plants to the JPS grid.

7.1 Base Year and Discount Rate

All costs are expressed in US dollars and referenced to 2018 for the IRP-1 analyses and in 2021 US$ for the IRP-2 analyses.

The discount rate used in IRP-1 study is set at 7.44 percent and is the post-tax weighted average cost of capital (WACC). This metric is used to compute present value of costs to the reference year. The WACC applied in IRP-2 is 7.91%. This rate was determined by the OUR in its 2019-2024 tariff review determination.

7.2 Economic Life of Generating Resources

The determination of the system expansion investment costs, and operating costs in present value terms is a key feature of the expansion planning model. Consequently, the determination of the preferred portfolio plan is based on assumptions related to the economic life of the existing and candidate plants and the discount rate assumed.

The assumptions on the economic life of generating candidate plants are based on provisions of the JPS electricity Licence. For existing plants and candidate plant options the following economic lives were assumed in the update as outlined in Table 7-1. The economic life of IPP owned generating assets are tied to the respective PPA of 20 years.

Table 7-1: Generating Plant Planning Life

Plant Technology Type	Planning Life (Year)
Hydroelectric	30
Open Cycle Gas Turbines	20
Combined Cycle Gas Turbines	30
IPP Generating Assets	**Year**
Medium Diesel Plant	20
Solar PV Plant	20
Wind Plant	20
Batteries Energy Storage System	15

7.3 Unserved Energy

Energy not served or unserved energy is the energy demanded by consumers but not supplied (ENS) due to supply constraints resulting from generation shortage or other system constraints. The economic value of unserved energy was assumed to be valued at US$3.5/kWh (2018 US$) for IRP-1 and is representative of the cost to the economy for the shortfall in supply. This value was retained in IRP-2 but adjusted to 2021 price level to US$4.266/kWh.

7.4 Loss of Load Probability (LOLP)

The reliability criteria used to identify the need for new generating capacity is the Loss of Load Probability (LOLP). The benchmark value applied by IRP-1 for the JPS system grid is 0.55% or approximately 2 days per year. This value represents the chance that the demand will outstrip the available capacity for a total of 48 hours in any year given the planned maintenance, force outage rates and the demand. This value is also utilized in IRP-1 and IRP-2.

7.5 Technical Operating Parameters

7.5.1. Reserve Margin

A planning reserve margin of 20% was used in the planning of the operation of the generating system and represents the percentage by which the installed firm capacity exceeds the system peak load demand. This implies that based on the size of units or blocks of a generating unit, JPS will be able to take out the largest single block of a generating unit for planned maintenance and meet the system peak demand under a single contingency case. This level of reserved margin was used in IRP-1 and IRP-2. The key economic and reliability criteria for the generating system planning development and operating security are shown in the Table 7-2.

Table 7-2: Key Planning Parameters

Economic Parameters	
Parameter	Value
Ref. Year for discounting	2021
Prices	US$
Discount Rate	7.91%
Cost of unserved energy	US$4.27/kWh
Reserve Margin	20%
LOLP	2 days/year

7.5.2. Electricity Sector Codes

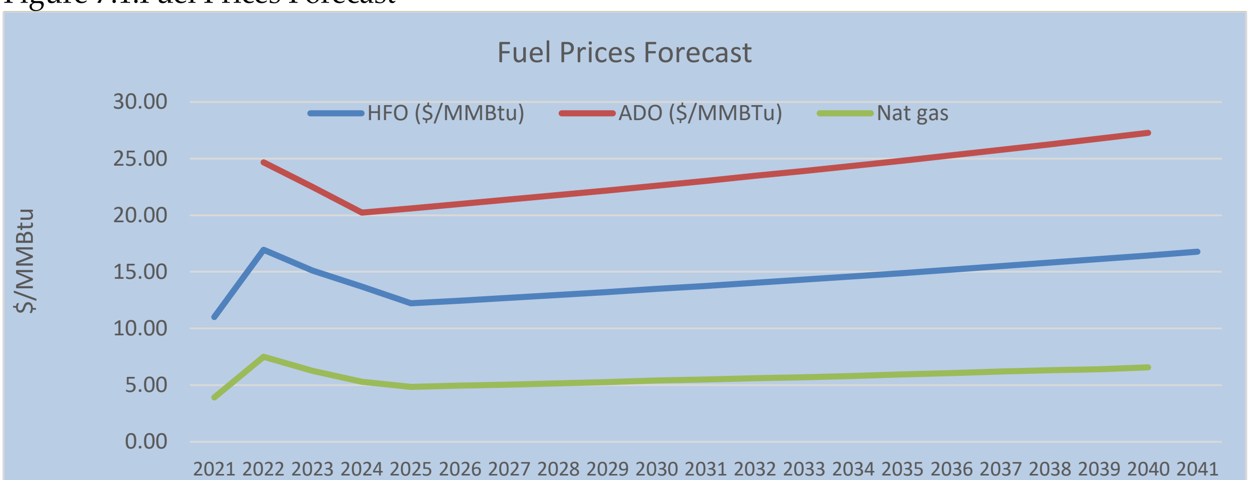
The generating and transmission systems technical operating parameters remained unchanged for the update and represented those limits that are required to be met based on the electricity sector operating codes. Details of the operating parameters are provided in section 3.9 of IRP-1 report.

7.6 Fuel Pricing and Forecasts

The thermal plants use fossil fuels. The fuel prices forecasts provided are based on public data sources. The fuels utilized consisted of petroleum products such as diesel fuel oil and heavy fuel oil refined products. Natural Gas was included in the Jamaican electricity sector fuel mix in 2017 and in 2021 became the dominant portion of the fuel used for electricity generation.

Refined petroleum product (i.e., diesel, heavy fuel oil, liquefied petroleum gas) spot forecasts are recommended to be derived from a publicly available source and to capture international market influences driving fuel economics. Natural gas spot price forecasts are driven from supply/demand trends and tanker and storage implications for natural gas markets. Section 3.5 of IRP-1 details the methodology utilized for developing fossil fuel forecasts.

Figure 7.1:Fuel Prices Forecast



Source: 2022 EIA Annual Energy Outlook

Fuel prices for delivery at the generating sites are adjusted to account for the additional handling charges including freight, insurance, storage, delivery, and in the case of natural regasification and infrastructure charges. Figure 7.1 shows the forecasted fuel prices indices.

8. Candidate Plants Consideration

8.1 Technology and Costs Changes

Cost reductions are noted for the cost of renewable technologies relative to the costs employed in IRP-1. The changes in the pricing of these technologies are due to the improved performance level of modern wind turbines and solar PV plants relative to the technology of 10 to 20 years ago. The updated costs utilized in IRP-2 were based on current market levels but applied on the conservative side. The improvement in technologies performance and pricing trends in the renewable power industry are expected to result in costs reductions and improve performances of wind and solar PV power generation plants.

Table 8-1 indicates the industry performance a trends for wind turbines.

Table 8-1: Wind Turbines Performance Trends

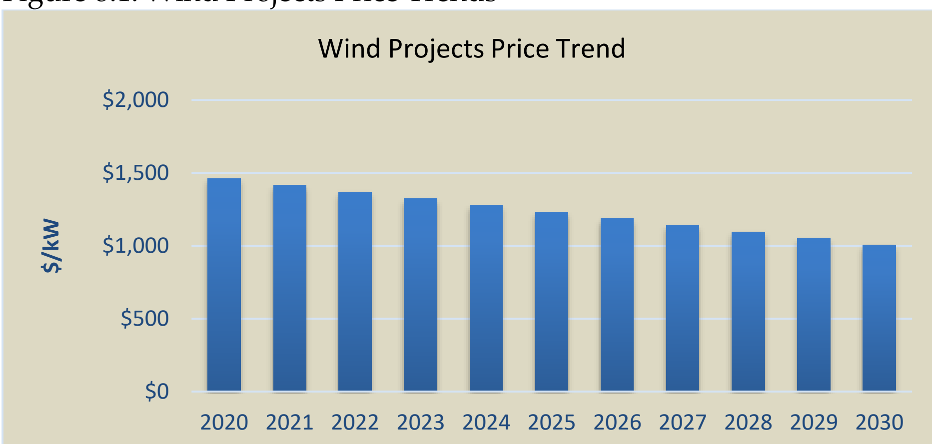
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		CF	CF	CF	CF	CF	CF	CF	CF	CF	CF	CF
Land-Based Wind - Class 6	Advanced	40%	41%	41%	42%	42%	43%	43%	44%	44%	45%	45%
Land-Based Wind - Class 6	Moderate	40%	40%	41%	41%	41%	42%	42%	42%	42%	43%	43%
Land-Based Wind - Class 6	Conservative	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Land-Based Wind - Class 7	Advanced	37%	37%	38%	38%	39%	39%	40%	40%	41%	41%	42%
Land-Based Wind - Class 7	Moderate	37%	37%	37%	37%	38%	38%	38%	38%	39%	39%	39%
Land-Based Wind - Class 7	Conservative	37%	37%	37%	37%	37%	37%	37%	36%	36%	36%	36%

*Class 6 wind speed weighted average is 7.8 m/s, Class 7 wind speed 7.4 m/s. CF - Capacity Factor.

IRP-1 wind capacity factor performance was based on current performance of dated technology plant currently in the Jamaican electricity system. This was assumed as 30% on average based on operating data from current wind plant operations. IRP-2 has assumed for the similar wind speed regime a performance capacity factor of 33% due to the newer technology available. This value is considered on the conservative side based on the capability of modern wind plants. The sites assessed for wind potential in Jamaica and the existing windfarm sites are assessed as having higher wind speeds than the class 7 sites. Figure 8.1 shows the projected cost trend of wind Projects.

Based on the conservative price reductions it is expected that prices will trend down by 31% by 2030.

Figure 8.1: Wind Projects Price Trends



Source: IRENA (2017), Electricity Storage and Renewables: Costs and Markets to 2030, International Renewable Energy Agency, Abu Dhabi

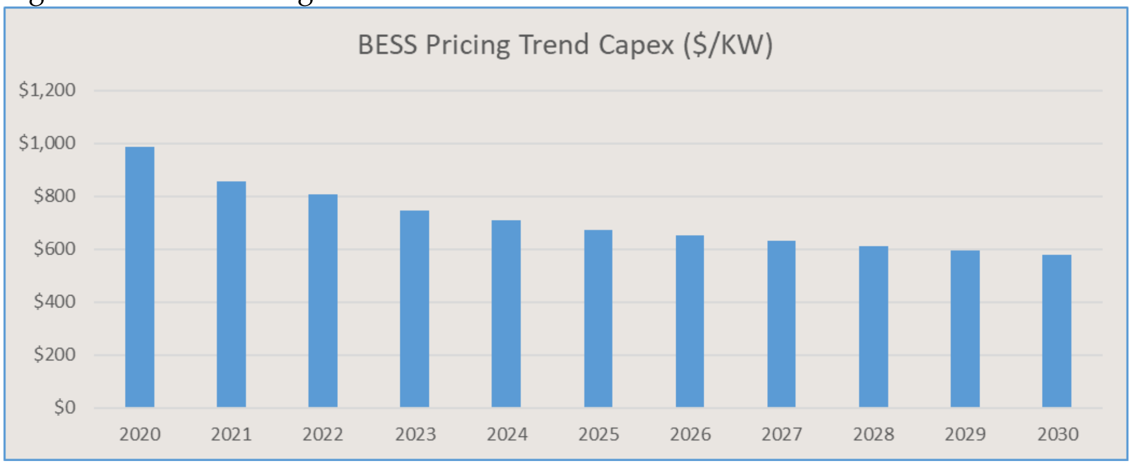
Plant performance capacity factor was conservatively assumed at 23%.

8.1.1. Battery Energy Storage System (BESS)

BESS is serving a significant role in allowing the increased integration of renewable energy resources in generating systems, by storing energy and releasing in a controlled manner when required. The ongoing improvement in battery technology is allowing longer storage duration and the commensurate steep reduction in costs, BESS is now competitive with other conventional technology plants in managing the variability and the unpredictability of wind and solar resources. These advancements are now allowing sustained grid operations with higher penetration of renewable energy within operational limits as prescribed by the Electricity Sector Book of Codes. The industry data indicates the potential of a reduction in pricing of 32% on a conservative basis and 48%

on an advanced over the period 2020 -2030. Figure 8.2 shows the trend in BESS pricing on the conservative trajectory.

Figure 8.2: BESS Pricing Trend



All values are given in 2020 U.S. dollars, using the Consumer Price Index (BLS, 2021) for dollar year conversions. For 15-year life (values in 2020$).

9. Pathway to 50% Renewable Portfolio Standard

In October 2018, the Prime Minister Hon. Andrew Holness announced that Jamaica will officially increase its target for use of renewable energy to 50 percent by 2030.[5]

The previous target of 30% renewables was set as policy by the Jamaican Cabinet. However, speaking at the handing over ceremony to install solar panels at the Office of Prime Minister on 2018 October 16, Prime Minister Holness said the previous target of 30% renewables to Jamaica's energy mix was not ambitious enough. The Prime Minister declared that;

"We are working even harder to a more ambitious target to reach 50% of our electricity generation being from renewables by 2030. Pushing our energy generation to be 50-50 by 2030; fossil fuels and renewables is in our national security interest, in our survival interest,".

The Prime Minister then indicated that at the present pace the previous target of 30% could be achieved by 2020 if the country remains on track in diversifying its energy use and called on all Jamaicans including Government agencies to remain committed to using renewables.

The following sections detail a pathway to enable the achievement of a renewable portfolio standard of 50% by 2030.

9.1 Demand Side Management

Demand side management programs are initiatives undertaken by the customers, utility and the GoJ with the specific aim of reducing electricity demand from end users. This consists of demand management and energy efficiency, including net billing measures to impact consumers' behavior in order to shape load profile for all round economic benefits. The programs are initiated by the GoJ through the responsible ministry (MSETT).

[5] Jamaica to Increase Renewables Target to 50% - PM Holness, October 17, 2018 by OPM communications

9.2 Energy Efficiency

The overall objective of the GoJ Energy Efficiency Programme as related to the electricity sector is to promote Energy Efficiency (EE) and Renewable Energy (RE) initiatives in government facilities. Specifically, the Programme proposed aim is to reduce electricity consumption within health, education and public agency (HEPA) government facilities, which would translate into lower GHG emissions.

Based on MSETT's assessment of the benefits of the EE programme it is estimated at 48.1 GWH or approximately 1% of net generation in 2022. It is estimated that an equivalent of 40,000 tonnes of GHG emissions will be avoided. While the reduction in electricity consumption from the past EE programmes would have been inherently factored in past demand forecasts.

9.3 Net Billing

One of the provisions under the Electricity Act relates to the Net Billing Program, which was established to allow customers the opportunity to generate their own electricity from renewable energy sources and sell excess electricity generation to JPS at a tariff equivalent to the monthly short-term fuel avoided cost. Under the Net Billing Program, the maximum allowable Renewable Energy Electricity Generation capacity is 10 Kilowatts (kW) for each Residential Customer and 100 kW for each Commercial Customer. As of July 31, 2022, a total of 1,026 licenses have been issued, representing a total program capacity of 22.4 MW of which 741 licensed corresponding to 13.35 MW have been commissioned by the grid operator.

9.4 Renewable Energy Technologies Options

Jamaica's renewable energy potential is discussed extensively in IRP-1 (section 3.1). Renewable energy in Jamaica is currently produced from hydro power, wind power and solar PV plants. In 2021 electricity generation from renewable energy sources supplied 12.41% of system net generation. Table 9-1 shows the contribution of fossil fuels and renewable sources to the energy mix.

Table 9-1: 2021 Generation Energy Mix

Sources							
HFO	ADO	LNG	Other	Hydro	Net Billing	Wind	Solar
24.49%	3.53%	59.55%	0.01%	3.20%	0.11%	6.15%	2.95%
Conventional Sources				Renewable Energy Sources			
87.59%				12.41%			

Renewable Technologies under consideration in the IRP to meet the upgraded renewable energy targets include; Solar PV plants, Wind plants, Hydro power plants biomass based plants and waste to energy plants.

9.4.1. Solar Resources

According to resource assessment studies carried out on behalf of MSETT by Worldwatch Institute collaborating with 3TIER, Jamaica shows tremendous solar potential. Annual average global horizontal irradiance (GHI – the most useful measure for solar PV power generation) ranges from 5 to 7 $kWh/m^2/day$ throughout most of the country, with some parts reaching 8 $kWh/m^2/day$. Net generation from solar PV plants contributed 2.95% of the system net generation in 2021 from an installed 57.5 MW of solar PV capacity. [6]

9.4.2. Floating Solar Power Plant Option

The deployment of ground mounted PV system requires considerable land areas, this requirement tends to put pressure on land use, especially in locations where lands are scarce and expensive. Floating Photo Voltaic (FPV) solution is gaining popularity in urban areas, close to load centers. It is estimated that the global capacity of FPV systems grew from less than 1 MW(DC) in 2007 to approximately 2.6 GW (DC) in 2020. Some advantages of FPV are; on existing bodies of water it frees up land for other purposes such as agriculture, less effect from shading, and reduced evaporation from the water bodies. The disadvantages of the FPV may include higher installed costs, potential negative environmental impacts, e.g. biofouling. Given, the relative newness of the technology there is very limited publicly available data on operations and maintenance costs, and system degradation factors, hence the projection of future performance may

[6] Worldwatch Institute/3Tier

not be accurately determined. Notwithstanding, this emerging technology can provide significant benefits to the integration of renewable energy in the Jamaican electricity sector and requires further consideration.

9.4.3. Wind Resources

Wind assessment study carried out by PCJ Wigton[7] showed excellent wind potential at the locations shown in Table 9-2. IRP-1 provides details of Jamaica's wind potential assessment (section 3.3). Based on the wind assessment potential Winchester in the parish of Portland has the greatest potential and should be explored further for new wind farm projects. This would lend diversity in the location of windfarm facilities. Rosehill is the site of the Wigton windfarm facilities.

Wind energy contribution to the net generation was 6.15% in 2021.

Table 9-2:: Wind Resource at Selected Sites

Wind Measurement Station	Wind speed at 80 m
Winchester, Portland	9.7
Rose Hill, Manchester	8.5
Kemps Hill, Clarendon	8.2

9.4.4. Offshore Wind Resource Options

The Petroleum Corporation of Jamaica carried out studies on wind resource assessments, investigating the potential of off shore wind sites for power generation. Preliminary assessments have indicated potential energy yield with net capacity factor of 29.7-42.9 %. Further technical and economic detail assessments are required to confirm the feasibility of these siting options[8].

9.4.5. Wind Plant Repowering Options

The total wind power installed capacity in Jamaica consists of 101.3MW located at three sites in Wigton, Manchester, Munro, St. Elizabeth and Malvern, St. Elizabeth. These

[7] Wigton/IDB Wind Assessment Study

[8] Jamaica Offshore Wind Feasibility Study Final Report (Public version) Petroleum Corporation of Jamaica.

facilities were installed between 2004 – 2016. Turbine sizes ranges are 750 kW to 2000 kW. The assessment reveals that wind turbine plants will come to their contractual expiry dates in 2024, 2028, and 2036. As these units age their performance and controllability deteriorate, thus not taking full advantage of the available wind resources. Repowering old wind power turbine with modern turbines has the potential to significantly improve generation at wind rich sites. Modern wind turbines have much improved capacity and have the potential to significantly increase the energy generation of these sites.

Repowering has the potential to improve energy security, maximize use of existing wind sites, ensuring increased integration of renewable energy sources in the generation mix, however, the issues of commercial contractual arrangements, regulatory framework, and interconnection have to be assessed in detail before implementation.[9]

9.4.6. Biomass and Waste to Energy

The status of data for biomass and waste to energy projects are not sufficiently comprehensive to permit the modelling as candidate projects for expansion at this time. However, as soon as more updated and complete data sets are available these technologies will be considered in future updates of the IRP.

Section 3 of IRP-1 report provides details of Jamaica's renewable energy potential.

9.4.7. Battery Energy Storage Systems (BESS)

The accelerating pace of integrating renewable energy into the energy supply mix, and improvements in energy storage technologies and prices are key drivers of the transition to cleaner electricity generation.

Large-scale battery energy storage systems capacity on the U.S. electricity grid has steadily increased in recent years, and the trend is expected to continue[10]. Battery energy storage systems have the technical flexibility to perform various applications for the electricity grid. BESS have fast response times to changing power grid conditions and

[9] Department of Energy Land Based Wind Market Report 2022 Edition

[10] U.S. Energy Information Administration | Drivers for Standalone Battery Storage Deployment in AEO2022

also stores excess generation from renewables, allowing variable renewable energy from solar and wind resources to be used during the time of highest value to the grid and not just when produced.

Battery storage provides flexible capacity and energy to the power grid that is used in a wide range of applications, which is categorized into two primary types:

- Capacity Reserve: Batteries contribute to capacity reserve margin.
- Ancillary Services: Batteries help maintain grid stability through frequency response (maintaining grid frequency) and spinning reserves (quick responding reserves for sudden system disruptions).

10. IRP-2 Scenarios

Addressing the rapidly growing penetration of renewable energy sources, RE price changes, advancement in technology in particular BESS, uncertainty in weather conditions and system load has been a significant challenge in the planning and operation of modern power systems. To adequately address these uncertainties and their potential risks, scenario analysis was used in the evaluation of the robustness of the preferred portfolio plan to changes in the key assumptions. Primary consideration was given to the scenario analysis of 50% RE integrated power system and evaluating the impact on the optimization objective function.

Additional scenarios were performed to further investigate and evaluate the perceived risks associated with the adoption of new RE technology in particular BESS under abnormal conditions. This is in light of the IRP-2 proposed preferred generation portfolio implementation plan of over 264MW of 2-hours BESS towards achieving the 50% RPS target. The implementation plan also recommends the retirement of all thermal fossil fuel plants that are scheduled for retirement. This is a significant shift from convention and therefore requires special review and scrutiny to ensure that these contingency plans and solutions are optimal, affordable and transitional.

Based on the above consideration, the following scenarios were assessed:

1. High Load - This represent 100% increase in the system annual growth rate.
2. High Fuel price – This represent a 10% increase in annual forecasted fuel price.
3. Seven (7) days of operation with very limited or no solar and wind generation.
4. Increases in RE technologies investment costs of 10% and 20% to test the cost robustness of the preferred portfolio.
    a. 10% increase in Fixed and FO&M costs for Solar, Wind and BESS
    b. 20% Increase in Fixed and FO&M costs for Solar, Wind and BESS
5. The impact on total system cost and the RPS target of granting extension to selected thermal PPA expiration to manage the risk of new RE technologies adoption and system contingencies.

10.1 Scenario 1 & 2 – High System Load Demand and Fuel Forecasts

The high system load demand and fuel forecasts scenarios were evaluated to assess the impact on system costs, LCOE and the generation preferred portfolio. The following table 10-1 summarizes the findings.

10.1.1. Result/Findings Scenarios 1&2

Table 10-1: Scenario 1&2 – High Load Demand and Fuel Forecasts

Scenario		System Cost		LCOE	
Load	**Fuel**	**2030 Var (%)**	**2041 Var (%)**	**2030 Var (%)**	**2041 Var (%)**
Reference	High	5.7	8.5	1.7	1.9
High	Reference	1.9	4.1	0.2	0.1

There was a 5% reduction in generation capacity over the 20 years planning horizon for the period 2031 - 2035. This is represented by a 60MW reduction in RE (Wind) and 50MW reduction in BESS capacity.

10.2 Scenario 3 – Seven Consecutive Days of Limited or No Solar and Wind Generation

The scenario of seven consecutive days with limited or no wind and solar generation was considered for evaluation in the year 2030 at 50% RE penetration. The month of July was used as the test case with the highest peak load and solar generation. Both existing and proposed solar and wind generation were set to zero MW for seven consecutive days.

10.2.1. Result/Findings Scenario 3

The BESS with total capacity of 264MW and energy storage of 528MWh per day was utilized more frequently during this period, charging from the thermal generating plants during off-peak load periods and discharging during evening peaks. The BESS utilized up to 75% of its energy capacity during the 7 days' period of no wind and solar power generation. The WKPP thermal plant was utilized extensively during this period.

10.3 Scenario 4 – Increases in RE Investment Cost of 10% and 20%

The base investment costs of the RE technology projects (Solar, Wind and BESS) were adopted from NREL The investment ($/kW) and FO&M costs were increased by 10% and 20% relative to the base costs in order to investigate the impact on system costs and LCOE by 2030 and beyond.

10.3.1. Results/Findings Scenario 4

a. 10% Price Increase – The system costs and LCOE increased by 2.2% and 6.6% respectively relative to the preferred plan over the 20 years planning horizon. No candidate conventional plant was selected over the 20 years planning horizon.
b. 20% Price Increase –The system costs and LCOE increased by 4.4% and 14.4% respectively relative to the preferred plan over the 20 years planning horizon. No candidate conventional plant was selected over the 20 years planning horizon.

10.4 Scenario 5 – Assessment of Impact of Expired Fossil Fuel Plant(s) Extension

The preferred generation portfolio proposed no conventional or thermal plant capacity, however, there are contingency conditions that may warrant the use of additional thermal generation as a solution such as (i) the loss of the Old Harbour to Duhaney 138kV transmission line for extended period, (ii) extraneous condition such as Scenario 3, and (iii) transitional plan to facilitate the adaption of new BESS 2-hours duration technology. For condition (iii) based on international market projections (NREL/EIA) by 2025, ESS is highly expected to be an integral part and main stay for the utility generation system.

10.4.1. Result/Findings Scenario 5

The existing generating plants within the Corporate Area were identified as the more suitable thermal plants for extension considering the bottleneck constraint for power imports through the Duhaney substation. These plant(s) will be utilized primarily for back-up purposes and therefore will have little or no impact on the RPS and GHG emissions.

10.5 Scenario Assessments Summary

Tables 10-2 and 10-3 summarizes the impact of the System Costs and LCOE changes over the IRP planning horizon for the above scenarios described.

The findings from the scenarios evaluated, which takes into consideration the impact on total system costs, LCOE and the RE penetration over the planning horizon showed minimal or no change to the preferred generation portfolio. The findings are indicative of the robustness of the preferred generation portfolio to changes in the key parameters.

Table 10-2: Scenario – Impact on System Costs PV (Variance)

Year	Scenario - Impact on System Costs PV (Var %)				
	Hi-Load	Hi-Fuel	10% RE Investment Cost Increase	20% RE Investment Cost Increase	Thermal Plant(s) Retirement Ext.
2030	1.9%	5.7%	1.1%	2.3%	0.4%
2041	4.1%	8.5%	2.2%	4.4%	0.2%

Table 10-3: Scenario – Impact on System LCOE (Variance)

Year	Scenario - Impact on LCOE (Var %)				
	Hi-Load	Hi-Fuel	10% RE Investment Cost Increase	20% RE Investment Cost Increase	Thermal Plant(s) Retirement Ext.
2030	0.2%	1.7%	3.1%	6.2%	0.06%
2041	0.1%	1.9%	6.6%	14.0%	0.05%

11. IRP-2 Preferred Implementation Plan

Table 11-5 details the generation resource preferred implementation plan required to meet the mandated renewable portfolio standard of 50% by 2030 at least cost while meeting the reliability standard. If the projects identified are implemented according to the implementation schedule, then by 2030 the penetration of renewable energy sources in the generation mix will achieve a 51.5% share of renewable energy.

11.1 IRP-2 Resource Additions and Retirements

11.1.1. Procurement Lead Times

The IRP-2 portfolio schedule of plant additions has taken into account a realistic lead time to procure the identified resources. The first year that a plant is eligible to be chosen in the expansion program is influenced by the timelines for activities such as feasibility and engineering studies, project approval, development and publication of Request for Proposal (RFP), bid evaluation, negotiation and EPC contractor selection, securing financing, environmental permitting, the actual construction and commissioning among other things. Details of the lead times for each technology and the first year eligible for operations when implemented through a normal execution process are shown below.

Table 11-1: Technology Lead Time to COD

Technology Type	Duration	Earliest
Hydroelectric	4.0	2027
Onshore Wind	3.0	2026
Solar PV	3.0	2026
Battery Energy Storage	2.0	2025
Simple Cycle Gas Turbine	2.0	2025
Combined Cycle Gas	4.0	2027
Medium Speed Diesel	3.0	2026
Waste to Energy (WTE)	4.0	2027

11.1.2. IRP-2 Generation Resource Additions

The analyses considered two scenarios to advise on the course of action for the implementation plan. A constrained annual renewable plants addition/integration to the grid (Scenario A). The analyses also considered the scenario (scenario B) of a less constrained renewable plants addition/integration to the grid analysis. Table 11-8 shows the summary results of the scenarios.

The updated preferred portfolio requires the generating plants installation and retirement schedules detailed in Table 11-2 to meet the sector objectives. It is noted that scenario A with a lower RE penetration of 42% and approximately 8% reduced investment cost resulted in an increased total system generation cost as the renewable energy portfolio standards of 50% by 2030. Scenario B on the other hand will achieve the mandated renewable energy portfolio standard by 2030 at 49.8% and at a lower overall fuel cost, GHG emission and generation LCOE. Table 11-2 shows the highlights of the preferred portfolio plan.

Table 11-2: IRP-2 Preferred Portfolio Highlights

Procurement of:

- 344 MW of wind plants comprising of 201 MW of plants between 2025 to 2030, 143 MW between 2031 to 2041.
- 34.3 MW of hydro power plant capacity, comprising of 12 small hydro plants across the country installed between 2027 to 2033.
- 1143 MW of solar PV plants comprising of 540 MW between 2025-2030 and 604 MW between 2031 to 2041.
- 493 MW of 2-hour battery energy storage systems (BESS) with 264 MW between 2024 -2027, 229 MW between 2033 to 2037.

Retirement of:

- 60 MW, 124 MW of IPP Diesel plants in 2024, and 2026 respectively
- 131.5 MW of combustion turbines and 40 MW JPS diesel plants in 2027
- 65.5 MW of IPP diesel plant in 2032
- 3 MW, 38 MW and 60.3 MW of wind plants in 2029,2032 and 2037 respectively.
- 20 MW of solar plant in 2037.

Achievement of:

50% renewable energy portfolio standard by 2030.

Reduction of:

- BOE imported for electricity sector from 5.97 million BOE in 2022 to 3.75 million BOE in 2030, reduction of approximately 2.21 million BOE per annum.
- Reduction in GHG gas emissions from 2.15 million tonnes in 2022 to 1.29 million tonnes by 2030 or an average reduction of 0.861million tonnes per annum. A total reduction of 17.5 million tonnes of GHG emissions over the planning period.

11.1.3. IRP-2 Resource Retirements

The updated preferred portfolio requires that several JPS owned plants be retired and IPP contracts ended on their expiry over the 20-year planning period.

Generating plants are assumed to be commissioned in service at the beginning of the year stated, and retirements are effective at the end of the year stated.

The preferred portfolio plan if implemented according to the proposed schedule will achieve a renewable penetration standard of 49.8% by 2030, thus satisfying the mandated RPS of 50% renewable energy in the mix by 2030, and beyond 2030, 72% by 2041 if timely executed.

11.2 Summary of Changes Effected

The changes in electricity demand, the significant increasing of the RPS from 30% by 2030 to 50%, and the extended time frame for the retirement of 171.5 MW of JPS plant capacity have necessitated detailed modelling and analyses of the electricity system to update IRP-1 to ensure the relevance of the IRP to the requirements of the Jamaica Electricity Sector is preserved. Table 11-3 summarizes the changes in key parameters and assumptions made in IRP-2 relative to IRP-1.

Table 11-3: IRP-1 & IRP-2 Comparison

	IRP1	IRP 2	Change
Parameters/Assumptions			
Power Market Forecast			
Base Peak Demand Forecast 2018(MW)	657.0	n/a	
Peak Demand Forecast 2022(MW)	705.0	644.0	8.6% reduction (61 MW)
Peak Demand Forecast 2030 (MW)	798 MW by 2030	678 MW by 2030	120 MW reduction
20 Year Demand Growth Rate (CAGR)	1.48%	0.60%	50% Reduction
Base Energy Demand 2018 (GWh)	4,490	n/a	
Base Energy Demand 2022 (GWh)	4,824	4,415	8.4% reduction
Base Energy Demand 2030 (GWh)	5,453	4,698	13.8% reduction
Existing System			
2018 System Installed Capacity (MW)	974.3	n/a	
2022 System Installed Capacity (MW)	1194.3	1059.0	145 MW reduction
JPS Existing Plant Retirement (MW)	114.0	285.5	171.5 MW increase
IPP Diesel Plant Retirement (MW)	249.9	249.9	None
RE Plant Retirement (MW)	80.3	101.3	21 MW increase

	IRP1	IRP 2	Change
Fuel Price Forecast			
Natural Gas (CAGR)		2.7%	
Fuel Oil (CAGR)		-0.1%	
Diesel Oil (CAGR)		0.45%	
Economic Parameters			
Base Year for discounting	2018	2021	
WACC (Post Tax)	7.44%	7.91%	6.3% reduction
Cost of unserved energy($/MWh)	3500 (2017$)	4266 (2021$)	No real change
Reliability			
LOLP	0.55%	0.55%	No change
Minimum Reserve Margin	20%	20%	No change
Legislative & Regulatory Changes			
RPS (RE percent of generation)	30% by 2030	50% by 2030	66% increase

Tables 11-4 and Table 11-5 provide the detailed portfolio plans for IRP-1 and IRP-2.

Table 11-4: IRP-1 Preferred Portfolio Plan Details

Year	Peak Load	Resource Additions, Conversion & Retirements	Firm Cap Addition	Retired Capacity	RE Cap Addition	System Installed Capacity	System Firm Capacity	Reserve Margin
	MW		MW	MW	MW	MW	MW	%
2018	657.0	No new resources commissioned	-		-	974.3	824.4	25.5%
2019	667.9	Commission 192 MW CCGT plant at Old Harbour, commission 14 MW Distributed generation.	206.0		-	1,217.3	1030.4	54.3%
2020	681.0	Commission 94 MW CHP at Jamalco, retire 262 MW JPS steam units, retire 2 MW cogeneration	94.0	264.0	-	1,047.3	860.4	26.3%
2021	693.9	No new resources commissioned				1,047.3	860.4	24.0%
2022	705.8	Commission 107 MW solar, commission 40 MW wind plant			147.0	1,194.3	860.4	21.9%
2023	718.0	Commission 36 MW Hydro plants, 18 MW WTE plant, commission 20 MW biomass plant	74.0			1,268.3	898.4	25.1%
2024	730.4	Commission 107 MW Solar PV, commission 47 MW wind plant, commission 18.5 MW new thermal plant,	18.5		154.0	1,441.3	916.9	25.5%
2025	743.1	Commission 120 MW thermal plant, retire 60 MW IPP diesel plant,	120.0	60.0		1,501.3	976.9	31.4%
2026	753.8	Commission 34MW wind, commission `120MW of thermal plant, retire 124.4MW IPP diesel	120.0	124.4		1,497.0	972.5	29.0%
2027	764.6	Commission 77 MW of solar plant, Commission 34 MW of wind plant			111.0	1,608.0	972.5	27.2%
2028	775.6					1,608.0	972.5	25.4%
2029	786.7	Retire 3 MW Wind		3.0		1,605.0	972.5	23.6%
2030	798.1	Commission 40 MW thermal plant	40.0			1,645.0	1012.5	26.9%
2031	807.9					1,645.0	1012.5	25.3%
2032	817.7	Commission 123 MW of solar plant, retire 38 MW wind plant			123.0	1,729.5	1012.5	23.8%
2033	827.7	Commission 60 MW solar plant, retire 65.5 MW IPP diesel		65.5	60.0	1,724.0	947.0	14.4%
2034	837.9	Commission 37 MW of solar plant			37.0	1,761.0	947.0	13.0%
2035	848.2	Commission 20 MW of solar plant,			20.0	1,781.0	947.0	11.7%
2036	858.6	Commission 10 MW of solar plant, commission 40 MW thermal plant,	40.0		10.0	1,831.0	987.0	15.0%
2037	869.2	Commission 590 MW of solar plant, retire 114 MW of CCGT, retire 20 MW solar		134.0	590.5	2,226.2	873.0	0.4%
		PV Total Programme Cost (US$000)	**6,423,858**					
	Levelized cost of energy (LCOE)2021$ US¢/kWh		**15.25**					

Table 11-5: IRP-2 Preferred Implementation Plan Details

Year	Peak Load	Resource Additions, Conversion & Retirements	Firm Cap Addition	Retired Capacity	RE Cap Addition	System Installed Capacity	System Firm Capacity	Reserve Margin
	MW		MW	MW	MW	MW	MW	%
2022	644	Installation 50 MW of BESS plant				1,040.32	882.02	36.96
2023	653					1,040.32	88.02	33.07
2024	658		50			1,090.32	932.02	41.64
2025	664	Commission 60 MW wind plant, 90 MW solar PV plant, 75 MW of BESS facility, Retire 60 MW IPP diesel plant	64.0	60.0	150.0	1,244.26	935.96	40.96
2026	667	Commission 60 MW wind plant, 90 MW solar PV plant, commission 75 MW of BESS facility, Retire 124.4 MW IPP diesel plant.	64.0	124.4	150.0	1,344.90	886.6	32.92
2027	669	Commission, 60 MW wind plant, 90 MW solar plant, 12.7 MW hydro plan and 75 MW of BESS facility. Retire 171.5 MW JPS thermal Plants comprising 40 MW diesel plant and 131.5 MW gas turbine plants.	87.7	171.5	163.0	1,411.10	802.21	20
2028	670	Commission 7 MW of hydro plants, 21 MW of wind plants and 90 MW of solar plants.	7.0		119.0	1,528.71	810.21	20.93
2029	675	Commission 90 MW solar plant, 11 MW hydro plant. Retire 3 MW of wind plant	11.0	3.0	101.0	1,627.72	821.22	21.12
2030	678	Commission 90 MW of solar plants.			90.0	1,717.72	821.22	21.12
2031	679	Commission 90 MW of solar plants and 2 MW of hydro.	2		92.0	1,809.80	823.2	21.25
2032	679	Commission 57 MW of wind plants, 90 MW solar plants and 1 MW hydro plant.	1		147.0	1,957.58	824.25	21.39
2033	682	Commission 34 MW of solar plant. Commission 60 MW BESS. Retire 65.5 MW of IPP diesel plant	60.0	65.5	34.0	1,985.35	818.4	20.00
2034	684	Commission 2 MW of BESS plant.	2.0		0.0	1,987.75	820.80	20.00
2035	686	Commission 25 MW of wind plant, 2 MW of BESS plant	2.0		25.0	2,014.92	823.20	20.00
2036	691	Commission 84 MW of solar plants and 56 MW of BESS plants.	56.0		84.0	2,154.69	879.00	27.21
2037	700	Commission 90 MW of solar plant, and 75 MW of BESS plants. Retire 114 MW CC plant.	75.0	114.0	90.0	2,205.39	840.00	20.0
2038	708	Commission 2 MW of wind plant, 70 MW of solar plants, retire 18 MW of wind plant and 10 MW of BESS plant.	10	18.0	72.0	2,286.56	849.60	20.0
2039	715	Commission 13 MW of BESS plants, 60 wind plants, 90 MW solar plants.	13.0		150.0	2,449.50	862.54	20.63
2040	721	Commission 11 MW of BESS plant and 23 MW of solar plants.	11.0		23.0	2,483.33	873.60	21.17
2041	728	Commission 33 MW of solar plant			33.0	2,516.46	873.60	20.00
		Present Value (US$'000')	**5,920,809**					
		Levelized cost of energy 2021$ (US¢/kWh)	**11.56**					

11.3 Impact on Fuels Consumption and GHG Emissions

11.3.1. System Energy Mix

Table 11-6 shows the progression towards meeting the renewable energy portfolio standard of 50%. It is noted that by 2030 renewable energy and natural gas will be the dominant fuel sources, and by 2040 over 72% will be generated from renewable energy sources. The impact of this transitional development will be to significantly lessen the fuel prices on electricity cost.

Table 11-6: System Energy Mix Progression

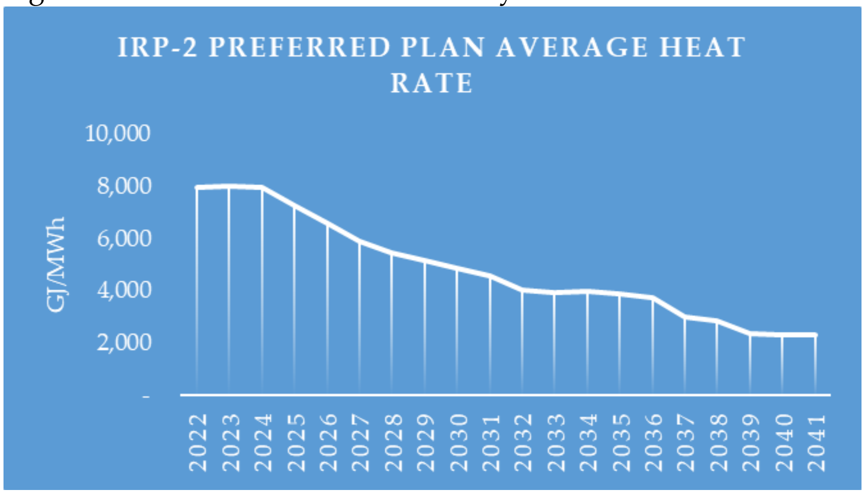
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Renewable %	11.5%	11.3%	11.3%	19.1%	26.7%	35.7%	41.8%	46.1%	49.8%	63.4%	78.6%
Nat Gas	77.4%	77.2%	76.7%	74.9%	72.8%	64.3%	58.2%	53.9%	50.2%	36.6%	21.4%
ADO	11.1%	11.5%	12.0%	6.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
HFO	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

11.3.2. System Heat Rate

The system heat rate is generically defined as the aggregate amount of input energy necessary to serve the system load, typically expressed as BTU / kWh or KJ/kWh. The system heat rate will vary as a function of the resource mix, and attendant fuel types and individual unit heat rates. Note that a lower heat rate is inherently preferable as it indicates a lower amount of energy input to create each unit of output.

The System Heat Rate indicates the overall Generating System efficient in converting fuel into useful electrical energy. The Figure 11.1 below shows that the system heat rate reduces by 42 percent over the first eight years or by 2030 of the plan as old and inefficient oil generators are replaced by renewable plants. At the end of the planning horizon, the System Heat rate has been reduced by 71 percent compared to the start in 2022. This significant reduction is directly attributable to the level of penetration of renewable energy plants.

Figure 11.1:IRP-2 Preferred Portfolio System Heat Rate



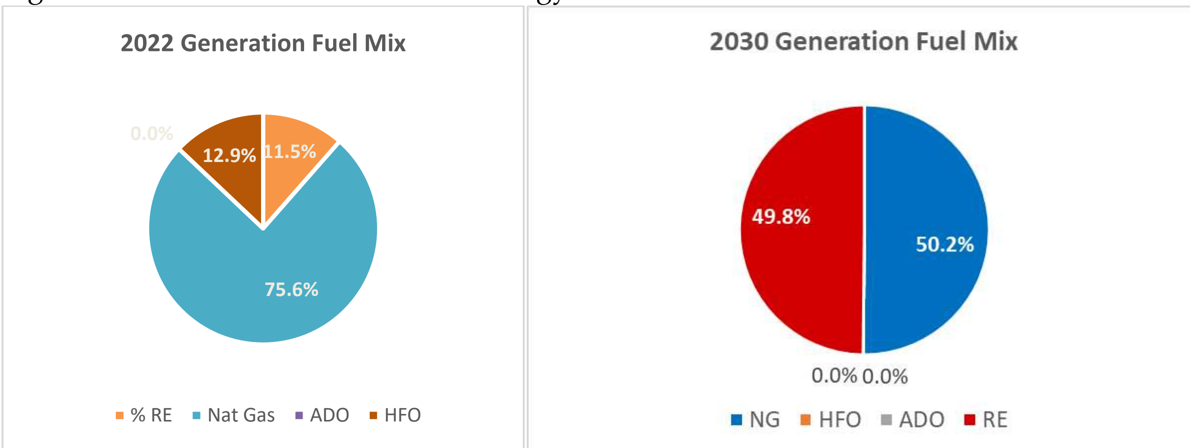
11.3.3. System Energy Mix Comparison IRP-1 and IRP-2

Table 11-7 shows the progression of renewable energy integration in the energy mix. Figure 11.2 show the generation energy mix for 2022 and projected for 2030.

Table 11-7: Energy Mix IRP-1 & IRP-2

	IRP-2				IRP-1			
	RE	NATGAS	HFO	ADO	RE	NATGAS	HFO	ADO
	%	%	%	%	%	%	%	%
2020					18.27	66.79	14.14	2.6
2021							18.8	2.7
2022	11.5	75.6	12.9	0.0	11.3	70.0	15.9	2.8
2025	19.1	73.2	7.7	0.0	30.11	69.55	0.29	0.0
2030	51.5	48.5	0.0	0.0	31.02	68.99	0.0	0.0
2035	56.3	43.7	0.0	0.0				
2037	62.9	37.1	0.0	0.0	49.37	50.62	0.0	0.0
2040	72.0	28.0	0.0	0.0	n/a	n/a	n/a	0.0

Figure 11.2: 2022 & 2030 Generation Energy Mix

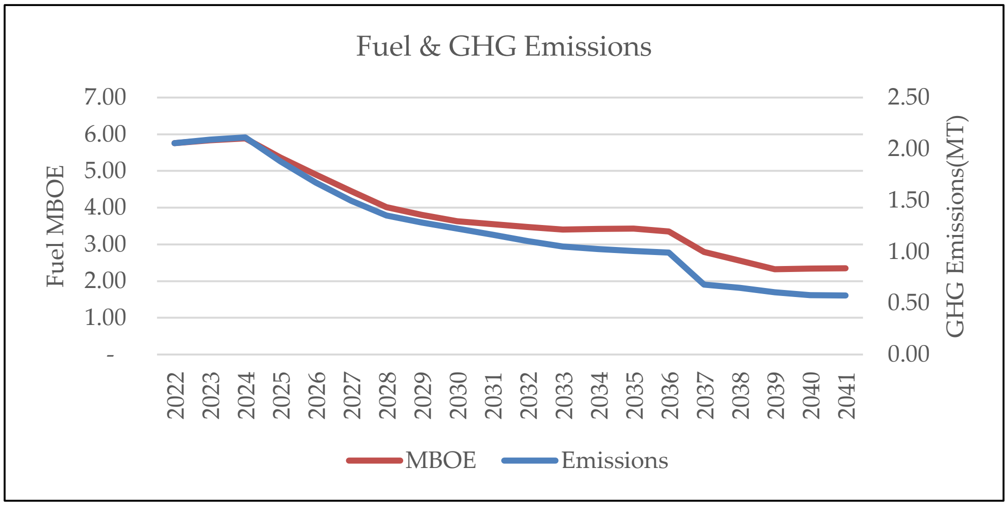


11.4 Impact on Fuel Utilization and GHG Emissions

The progressive increase in renewable energy integration in the Jamaican electricity sector will result in approximately 2.5 million barrels of oil equivalent (BOE) of imported fuel avoided annually by 2030 and over 3.9 million BOE by 2040, resulting in a reduction of over 38.0 million MBOE of oil consumed over the planning period. This magnitude reduction in fossil fuel utilization will result in 18.5 million metric tonnes of GHG emissions avoided due to the integration of the renewable energy resources as proposed in IRP-2.

Figure 11.3 shows the fuel use and GHG emissions trend based on the preferred plan.

Figure 11.3: Fuel Use & GHG Emissions



11.5 Preferred Implementation Plan Investment Costs

Generating System Costs

Table 11-8 gives the generating system costs which include the investment costs, fixed and variable operating and maintenance costs, fuel costs and energy not supplied cost. The net present value (NPV) cost is used to compare different expansion scenarios. Costs are present value costs referred to the 1st of January of the base year 2021.

Table 11-8: Generating System Expansion Scenarios

Ref load & fuel price forecasts	A	B		
Renewable Portfolio Standard of 50%	**42% RE**	**Preferred Portfolio**	**Impact**	**Impact %**
PV Generating System Total Costs (US$'000')	5,920,809	5,922,243	1,435	0.02%
PV Fuel Costs (US$'000')	2,679,719	2,559,680	-120,038	-4.69%
PV Thermal Variable O&M Costs (US$'000)	29,499	28,102	-1,397	-4.97%
PV Build Cost (US$'000)	1,202,368	1,303,600	101,232	7.77%
PV Fixed O&M Costs (US$'000)	658,512	673,787	15,275	2.27%
Barrels of Oil Equivalent Consumed (BOE)	77,067,559	72,274,933	-4,792,626	-6.63%
CO2 Emissions (Tonnes)	26,333,876	24,801,157	-1,532,720	-6.18%
New Capacity Installed (MW)	2,003	2,113	110	5.21%
Firm Capacity Installed (MW)	874	874	0	0.00%
Renewable Capacity Installed	1,510	1,620	110	6.79%
BESS Capacity (MW)	493	493	0	0.00%
System LCOE (US$/kWh	112.83	110.19	-3	-2.40%
Renewable Energy Percent on generation	42.00%	49.80%	0.08	15.66%

Note: Scenario A: 42% RE Scenario B: 50% RE

The scenarios included; 42% RE penetration, which represent a constrained assessment limiting new RE capacity per year and (scenario A), with less constrained on new annual RE capacity additions. In the case of scenario, A, the RPS of 50% is not achieved by 2030, the renewable energy integration reaches 42% of the energy mix by 2030. Scenario B, will however, achieve the RPS of 50% with the achievement of 49.8 % integration of renewable energy in the energy mix. It should be noted that scenario B has a higher investment cost, however, the total system generation cost is less, primarily due to the reduction in thermal plants' imported fossil fuel and variable (O&M) costs. Scenario B (the preferred portfolio) also contribute to less CO2 emissions and system LCOE.

Table 11-9: Share of Investments by Technology

	Hydro	**Wind**	**Solar**	**Battery**
New Capacity (MW)	34.3	344	1143	493
% of Investment	5.8	22.9	50.1	21.2

Additional scenario analysis which assumes that JPS has not opted to replace the retired 171.5 MW of plants will result in approximately 2.2% lower overall cost, and a 5.8% reduction in GHG emissions over the planning period compared to the preferred portfolio Figure 11.4 shows the relative movements of the key components of the generation costs over the planning period. It is noted that as the investments in renewable energy and storage technologies are increased, fuel consumption is reduced considerably, and a commensurate reduction in overall generation cost. Table 11-10 shows the breakdown of investments cash flows across the various energy technologies.

Figure 11.4:Generation Cost Components

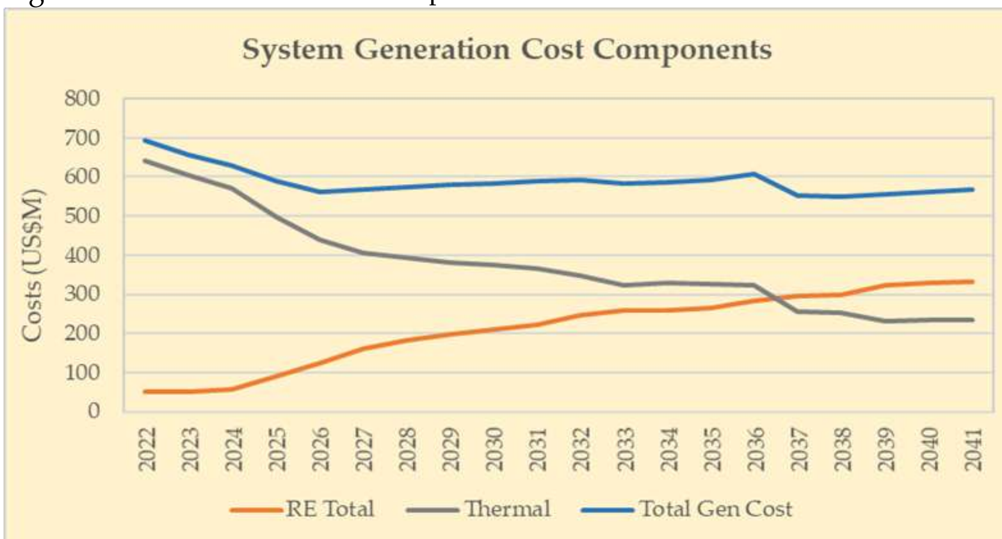


Table 11-10: Preferred Implementation Plan PV Investment Cash Flow

Fiscal Year	Capex Hydro Build Cost ('000)	Capex Wind Build Cost ('000)	Capex Solar Build Cost ('000)	BESS Build Cost ('000)	Total Cost ('000)
2022	-	-	-	-	-
2023	-	-	-	-	-
2024	-	-	-	36,209.82	36,209.82
2025	-	63,762.96	80,312.12	42,910.86	186,985.94
2026	-	59,089.02	74,425.10	46,643.83	180,157.95
2027	30,764.50	54,757.68	68,969.60	43,224.75	197,716.53
2028	20,854.55	17,928.60	63,914.00	-	102,697.15
2029	18,223.51	-	59,228.99	-	77,452.50
2030	0.00	-	54,887.40	-	54,887.40
2031	2,781.68	-	50,864.05	-	53,645.73
2032	2,229.78	35,443.38	47,135.62	-	84,808.78
2033	176.46	-	16,317.21	21,717.91	38,211.58
2034	-	-	-	811.80	811.80
2035	-	12,299.31	-	752.30	13,051.61
2036	-	-	32,433.28	16,208.78	48,642.06
2037	-	25,575.74	32,213.71	20,189.04	77,978.49
2038	-	7,730.31	29,852.39	2,394.77	39,977.47
2039	-	21,963.66	27,664.16	14,549.82	64,177.64
2040	-	-	6,485.34	16,066.84	22,552.18
2041	-	-	8,746.16	14,889.11	23,635.27
Total	**75,030.48**	**298,550.66**	**653,449.13**	**276,569.63**	**1,303,599.90**

Significant investments in renewable plants are required to meet the 50% renewable portfolio standard. It is estimated that approximately US$836 Million in new renewable plants and BESS are needed by 2030 to meet the RPS, while maintaining the requisite level of system reliability and operations criteria.

Tables 11-12 and 11-13 provide details of the roadmap towards meeting the IRP objectives to achieve reliable and economic energy supplies while meeting the prescribed renewable energy portfolio standard of 50% by 2030.

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Table 11-11: IRP-1 Preferred Implementation Portfolio Capacity

Plant Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Biomass	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
CapEx WTE	-	-	-	-	-	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
CapExBiomass	-	-	-	-	-	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CapExHydro	-	-	-	-	-	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
CapExSolar	-	-	-	-	107.0	107.0	214.5	214.5	214.5	291.5	291.5	291.5	291.5	291.5	414.0	474.0	511.0	531.0	541.0	1,130.5
Capex Wind	-	-	-	-	40.0	40.0	87.0	87.0	87.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0	121.0
CCGT	114.0	306.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	286.0
Cogen	2.0	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas turbines	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5	151.5
DG	-	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Hydro	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7
IPP Diesel	249.9	249.9	249.9	249.9	249.9	249.9	249.9	189.9	65.5	65.5	65.5	65.5	65.5	65.5	65.5	-	-	-	-	-
JPS Diesel	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
JPS Steam	262.0	262.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	20.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	37.0
Thermal	-	-	-	-	-	-	18.5	138.5	258.5	258.5	258.5	258.5	298.5	298.5	298.5	298.5	298.5	298.5	338.5	338.5
Wind	101.3	101.3	101.3	101.3	101.3	101.3	101.3	101.3	101.3	101.3	101.3	98.3	98.3	98.3	60.3	60.3	60.3	60.3	60.3	-
Grand Total	**974.3**	**1,217**	**1,047**	**1,047**	**1,194**	**1,268**	**1,441**	**1,501**	**1,497**	**1,608**	**1,608**	**1,605**	**1,645**	**1,645**	**1,730**	**1,724**	**1,761**	**1,781**	**1,831**	**2,226**
Firm cap	824.4	1,030	860.4	860.4	860.4	898.4	916.9	976.9	972.5	972.5	972.5	972.5	1,012.5	1,012.5	1,012.5	947.0	947.0	947.0	987.0	873.0
RE Capacity	150.0	187.0	187.0	187.0	334.0	370.0	524.5	524.5	524.5	635.5	635.5	632.5	632.5	632.5	717.0	777.0	814.0	834.0	844.0	1,353.2
Peak Load	657.0	667.9	681.0	693.9	705.8	718.0	730.4	743.1	753.8	764.6	775.6	786.7	798.1	807.9	817.7	827.7	837.9	848.2	858.6	869.2

Table 11-12: IRP-2 Preferred Portfolio Implementation Plan

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Combustion	152	152	152	152	152	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
IPP Diesel	250	250	250	190	66	66	66	66	66	66	66	0	0	0	0	0	0	0	0	0
CCGT	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	194	194	194	194	194
Cogeneration	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
JPS Diesel	40	40	40	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DG	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Wind	101	101	101	161	221	281	303	300	300	300	356	356	356	381	381	381	382	442	442	442
Solar	57	57	57	147	237	327	417	507	597	687	777	811	811	811	895	985	1055	1145	1167	1200
Hydro	29	29	29	29	29	41	49	60	60	62	63	63	63	63	63	63	63	63	63	63
BESS	0	0	50	114	189	264	264	264	264	264	264	323	326	328	384	459	469	482	493	493
Total	1040	1040	1090	1244	1345	1411	1530	1628	1718	1810	1958	1985	1988	2015	2155	2205	2287	2450	2483	2516

Table 11-13: IRP-2 Evolution of Renewable Energy Integration

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Wind	101	101	101	161	221	281	303	300	300	300	356	356	356	381	381	381	382	442	442	442
Solar	57	57	57	147	237	327	417	507	597	687	777	811	811	811	895	985	1055	1145	1167	1200
Hydro	29	29	29	29	29	41	49	60	60	62	63	63	63	63	63	63	63	63	63	63
BESS	0	0	50	114	189	264	264	264	264	264	264	323	326	328	384	459	469	482	493	493
Total RE	187	187	187	337	487	650	768	866	956	1048	1196	1230	1230	1255	1339	1428	1500	1650	1673	1706
Total RE+BESS	187	187	237	451	676	914	1032	1130	1220	1312	1460	1553	1556	1583	1723	1887	1969	2132	2165	2198
RE (GWh)	506	507	508	863	1218	1631	1910	2115	2298	2481	2834	2896	2896	2967	3143	3330	3475	3829	3881	3942
RE % of Gen	11.5%	11.3%	11.3%	19.1%	26.7%	35.7%	41.8%	46.1%	49.8%	53.7%	61.0%	62.2%	62.0%	63.4%	66.4%	69.8%	71.9%	78.3%	78.6%	78.9%

11.6 Avoided Generation Costs

The avoided cost determination is an important outcome of the IRP study. The avoided cost metric is the metric utilized to benchmark the entry level tariff for the addition of new generating facilities, and to set the allowable tariff projects awarded to JPS under the Right of First Refusal (ROFR) provisions of the Electricity Act (EA).

The IRP analyses has determined the avoided costs as set out in Table 11-14 below. The Electricity Act (the Act) requires that the avoided cost be updated every two years by the Ministry. The Act also stipulates that JPS in exercising the right of first refusal with respect to replacing existing generation capacity, the replacement cost of such capacity should not exceed the generation avoided cost.

IRP-1 analyses have determined that on a 20-year levelized cost basis, the avoided cost of generation is 10.29 US ¢/kWh (2018 US$). IRP-2 update as determined an avoided cost of **11.56 US¢/kWh** in 2021 US$. This is broken down as below. Section 4.2 of IRP-1 provides details of the avoided costs computation methodology.

Table 11-14: IRP-2 Avoided Cost of Generation

System Total (¢/kWh)	Thermal (variable) (¢/kWh)	RE (¢/kWh)	Energy Storage (BESS) Capacity ($/kW-Month)
11.56	**11.73**	**6.69**	**10.56**

11.7 Transmission Plan

The purpose of the transmission planning study is to develop plans and implementation schedules for expanding and upgrading the transmission infrastructure. This is in association with the generation expansion plans to economically and reliably supply the forecasted load and to integrate the planned resources into the power system subject to the electric grid interconnection guidelines and performance criteria. The transmission plan is therefore a function of the system load forecast and the generation implementation integrated resource plan. Transmission plans for the preferred generation expansion sequences were developed based on the siting of the new generation resources.

Based on the results of the load forecast the plan determine the best location of bulk step down substations, and develop several transmission alternatives to interconnect the generating plants to the load areas.

The transmission plan update development was based on the following activities.

- Considering factors such as; proximity of load to power sources, routing and right of way, voltage levels, comparative lengths of alternate routing, costs and maintenance.

- Collecting data and prepare assumptions which include technical information on existing and committed transmission system previous evaluation and simulation studies, load forecast, electrical parameters of future generating plants and non-generating alternatives such as demand side management programs.

- Data include but not limited to the following parameters; discount rate, interest during construction, operating costs, transmission system maintenance costs and outage rates, performance efficiencies, line loading and capacity limits, construction costs, lead time to complete, and expected operating life time.

- Generators and controllers, protection system including relay, circuit breakers and their settings.

The generation expansion sequence is planned to meet both the increased and forecast customer demand for electricity supply. Critical to this expansion process is the ability of the transmission grid to move bulk electric power from the power generating plant, to the distribution network in order to meet demand.

The transmission plan details the transmissions infrastructural requirements, both in terms of material/equipment and capital expenditures needed within a twenty-year period (2022 to 2041) in order for the grid operator JPS to meet its targets for network security and reliability at economic cost. The document also gives the timelines for the transmission system investment portfolio. Details of the transmission system planning are detail in section 3.7.5 of IRP-1 document.

11.8 The Updated Transmission Plan

11.8.1. Development of Base Transmission Plan

The alternate transmission plans meeting the requirements associated with the generation expansion scheme were developed and evaluated on a total least cost basis which include: (1) Capital investment of the facility and (2) cost of energy losses, and operating and maintenance expenses.

In carrying out the assessment of the existing system and in the determination of the transmission alternatives industry standard computer based transmission system planning and simulation techniques and models were utilized. The transient, dynamic and steady state response to various critical operating conditions for the forecasted loads, power interchange, outage contingency conditions and generation dispatch. These models include: (1) Load Flow, (2) Transient and Dynamic Stability and (3) Fault Current Study (Short Circuit study).

a) **Load Flow Analysis**: Load flow studies were performed in order to determine the load flows in normal and disturbed conditions (loss of generation and major transmission lines). The result of this analysis was used to determine the system requirements for reinforcement, reactive power compensation and for proper sizing of the transmission line and substation equipment.

b) **Fault Current Study**: The short circuit level of the power grid might be changed through the interconnection of new plants. Therefore, a fault current analysis was carried out and based on the study, an appropriate protection system be designed for the interconnected system, and reinforcement measures of the existing switchgear were identified as needed.

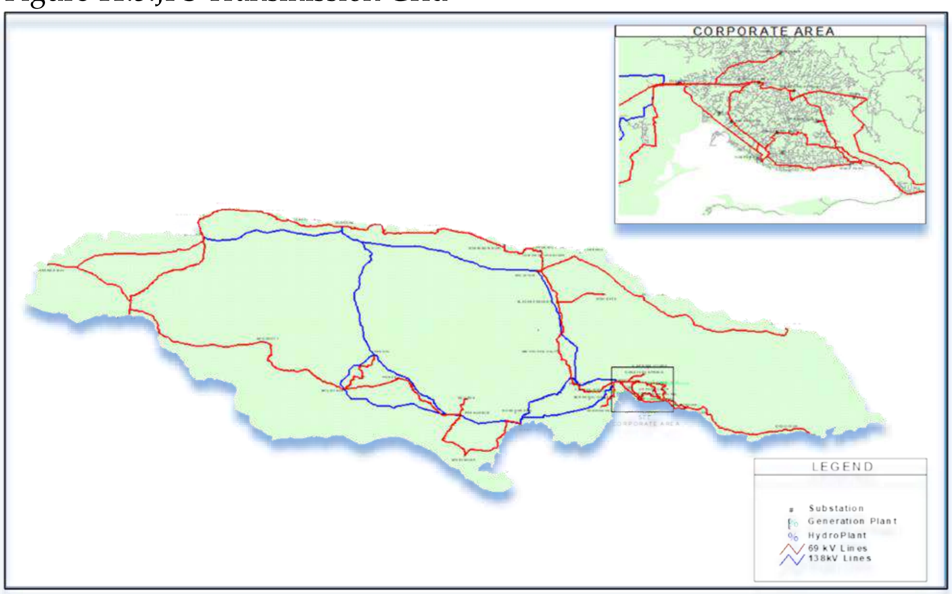
c) **Stability Analysis**: Stability studies were performed with the simulation of different abnormal conditions such as faults, sudden load changes and reduction of power generation, energy plant load variation, renewable and massive loss of generation in order to determine the system requirement of stabilization and compensation.

11.9 Transmission Development Plan

11.9.1. Existing Transmission System

The transmission system is comprised of 138kV and 69kV lines ring networks, of which the 138kV is the bulk power transmission network and spans 382km in length. The 69kV circuits, which operate as the sub-transmission system, span a length of 811km. The Corporate Area, which is the main load centre, is served by 105km of 69kV lines that accounts for 18% of the total sub-transmission network. There are 55 (JPS and privately owned) substations of which 44 provide distribution supply. There are nine (9) bulk power 138kV transmission substations connecting the 138kV system to the 69 kV voltage level by twelve (12) interbus transformers with a total capacity of 798 MVA. Figure 11.5 shows a geographical overview of the transmission system.

Figure 11.5:JPS Transmission Grid



The Corporate Area (Kingston and St. Andrew) accounts for approximately 50% of the system daily demand with over 90% of energy imported from the west of the island.

IRP-1 provided a comprehensive description of the growth and evaluation of the status of transmission grid in section 3.7. JPS, the system operator owns, installed, and operate the transmission network.

Since the publishing of the IRP-1 in September 2020 the transmission system has not changed relative to the assumptions included in the analyses. The project which was committed at the start of the 2018 IRP plan have since been constructed and commissioned into service, the 24.5MW hybrid Li-Battery/Flywheel ESS at the Hunts Bay substation.

11.10 IRP-2 Transmission Plan

The revised 2030 RE target of 50% coupled with VRE and BESS technology advancement and cost reductions are creating opportunities for Jamaica to lessen its dependence on imported fossil fuel, meeting its GHG target while reducing the costs of electricity to customers. The transmission grid impact assessment is therefore primarily focused on addressing the increase in VRE from 12.4% to 50% by 2030 and integration of 493MW of BESS energy capacity over the 20-years planning horizon. The transmission system assessment involves the review of transient, dynamic and steady state response to various critical operating conditions for the forecasted loads, power interchange, outage contingency conditions and generation dispatch.

The applications of BESS in the Jamaican electric grid will play a significant role to address the increasing VRE penetration while simultaneously addressing traditional generation and grid reliability and security requirements. Table 11-15 below identifies the value chain and benefits that the BESS design and locations are predicated.

Battery storage provides flexible capacity and energy to the power grid, and can be used in a wide range of applications that are categorized into two primary types:

- Capacity Reserve: Batteries contribute to the capacity reserve margin.
- Ancillary Services: Batteries help maintain grid stability through frequency response (maintaining grid frequency) and spinning reserves (quick responding reserves for sudden system disruptions).

Table 11-15: BESS Value Chain Identification

#	Application	Description	Duration of Service	Typical Value	Remarks
1	VRE Supply Regulation	Facilitates increasing VRE penetration	Seconds to minutes	Very High	Limits variability in supply
2	Firm Capacity	Provide reliable capacity to meet peak demand	4 + hours	Very high	Deferred peak plant investment
3	Operating Reserves			Very high	
- i	Primary Frequency Response	Very fast response to unpredictable variations in demand and generation	Seconds	Very high	
- ii	Regulation	Fast response to a random, unpredictable variations in demand and generation.	15 minutes to 1 hour	Very high	
- iii	Contingency Spinning	Fast response to a contingency such a generation failure	30 minutes to 2 hours	High	
- iv	Ramping/Load Following	Follow longer-term (hourly) changes in electricity	30 minutes to hours	Very high	
4	Virtual Transmission Line	Reduce loading on T&D system during peak times and N-1	Hours	Very high	Deferred T&D investments

11.11 IRP-2 Transmission Plan

Increasing VRE penetration from an existing 12% to 50% of net generation by 2030 requires fundamental changes to the grid development and operation to realize the revised generation portfolio, which is based on generation energy substitution and the integration of BESS technology. The generation energy substitution is primarily driven by a significant reduction in the revised 20-years demand forecast, which is two-fold:

1. A revised base year peak demand from 798MW (2030) to 678MW (2030), and
2. A revised average forecasted annual energy reduction of approximately 70% from 1.48% (IRP-1) to 0.75% (IRP-2) over the 20-years planning period.

In summary the IRP-2 transmission plan includes the integration of the proposed 493MW of BESS, the upgrade and construction of new transmission lines and substations to facilitate the introduction of new wind generation sites. In addition, the installation of substation bulk capacitor banks to provide additional voltage support within the Corporate Area.

In summary for the first 10 years (2022 – 2032) the main developments include the following:

1. Operate the transmission grid at 98% load power factor (PF) from the traditional 95%. This recommendation addresses the reduction in MVARs from the increasing VRE penetration.
2. All new wind and PV generation plants shall provide grid support for all states (steady, dynamic and transient) conditions by providing voltage support with the injection of reactive power.
3. All new wind and PV generation plants shall support grid disturbances and faults without being disconnected from the grid. That is, provides low voltage ride-through. (LVRT).
4. The application of smart grid technology to manage and provide the necessary MVARs support from the distribution grid by operating at 98% power factor.
5. 2-hours BESS technology with 4 quadrant operation at maximum rated power.
6. The application of Battery Energy Storage (BESS) technology to provide system transient stability, intermittency, firm capacity and deferred transmission line investment during emergency conditions.

11.11.1. Transmission Development Plans and Recommendations

The main observations and recommendations of the effects on the Transmission System by the year 2030 was extensively evaluated by the Grid Operator. The following refers:

5. Normal and abnormal conditions are adequately addressed with upgrade of specific existing transmission lines, substations and the construction of new transmission lines.

6. The synthetic inertia of the preferred portfolio BESS is adequate to mitigate against the threat of grid instability with the reduction in system inertia due to the displacement of thermal generation with VREs that affect the rate of change of system frequency during disturbances.

7. There is the need to assess and determine the feasibility of locations to site the quantity of Solar PV, Wind and 2-hour Energy Storage Systems slated to be installed in the Corporate Area.

8. The Analysis recommends the need for a new transmission corridor from Old Harbour into the Corporate Area. It further concludes that an Old Harbour – Three Miles 138 kV line would be more beneficial to customers than the alternative Old Harbour - Hunt's Bay 138kV line.

9. Further feasibility study is required of the physical capacity for the construction of the proposed solar, wind and battery locations, primarily in the Corporate Area.

10. Based on the results of the critical fault clearing times and short circuit analyses, with the integration of more VREs and BESS there will be a need to relook the protection coordination scheme system wide.

Consistent with the above the grid operator will perform a more detailed and comprehensive assessment of the transmission plan to adequately satisfy the requirement of the transmission grid over the medium to long term planning horizon. This will include the technical and economic feasibility and timing for the recommended transmission infrastructure upgrades.

12. Key Findings of Transmission System Plan

The following are the key findings based on the outcome of the transmission system analyses.

1. A major shift from the application BESS as frequency regulation to several ancillary services (dispatch-able, virtual transmission line, capacity reserve, contingency spinning).
2. The application of 2-hours BESS versus 0.45 minutes BESS currently installed at JPS Hunts Bay S/S.
3. The advancement and price reduction in BESS technology have made significant gains in providing opportunities for power grids to satisfy varying operating and planning requirements for increasing RPS.
4. With over 494MW of BESS planned over the 20 years' horizon the price of ESS continues to fall coupled with longer storage duration. The price of BESS is projected to reduce by over 50% by 2030. BESS is therefore shaping to be the transitional technology to reduce Jamaica's dependence on imported fossil fuel.
5. The applications of BESS technology are not site specific and therefore lends itself to several solutions on the transmission and distribution grid to mitigate existing and anticipated violations.
6. With over 90% of energy demand being imported from the west into the Corporate Area the necessary plans are required to consider increasing RE generation within and to the east the Corporate Area and/or a 138kV transmission line reinforcement from Old Harbour to Kingston.
7. The synthetic inertia of the preferred portfolio Battery Energy Storage Systems (BESS) was adequate to mitigate against the threat of grid instability with the reduction in system inertia due to the displacement of thermal generation with VREs that affect the rate of change of system frequency during disturbances.
8. The analysis recommends the need for a new transmission corridor from Old Harbour into the Corporate Area. It further concludes that an Old Harbour – Three Miles 138 kV line would be more beneficial to customers than the alternative Old Harbour - Hunt's Bay 138kV line.
9. Based on the results of the critical fault clearing times and short circuit analyses, with the integration of more VREs and BESS there will be a need to relook the protection coordination scheme system wide.

13. Key Findings of IRP-2

13.1 Key Findings

1. Significant changes in the global and local landscapes since the development of the 2018 IRP impacting the local electricity sector have made it imperative for MSETT to update the 2018 IRP based of the magnitude of the changes to the electricity market, technology developments and renewable procurement standards and emissions reduction upgrade.
2. The IRP-1 preferred portfolio implementation plan schedule is no longer feasible given that the procurement lead times for new plants and the low pace of procurement initiatives.
3. The load growth forecasted in IRP-1 did not materialize, and the recent load forecast projects a 120 MW reduction in peak demand relative to IRP-1 forecast.
4. The costs of renewable energy and storage technologies are trending down making future investments in renewable energy technologies more feasible.
5. Fuel prices are expected to show frequent fluctuations over short periods but long term trends are expected to be relatively stable.
6. Fuel price fluctuations will be less impactful on electricity prices based on the higher levels of renewable resources.
7. The least cost expansion option (Preferred Implementation Plan) is the expansion plan which assumes that the JPS ROFR plants is replaced by renewable capacity coupled with BESS.
8. The preferred implementation plan (least cost) will require the installation 1521 MW of clean renewable power comprising of 344 MW of wind plants, 1143 MW of solar PV plants, 34 MW of hydro plants over the 20 -year planning period. 493 MW of battery energy storage systems (BESS) will be required over the planning period 2022-2041 to successfully integrate this level of RE resources.
9. BESS will be required to play an important role to ensure system reliability, provide operational flexibility and minimize the extent of dump energy from renewable energy sources.
10. No new fossil fueled plant was selected as part of the preferred portfolio implementation plan.
11. The transition to a new dominant technology in RE and long duration BESS warrants the extension(s) of existing thermal generating plants within the Corporate Area for the medium term. The plant(s) will be utilized primarily for back-up purposes and therefore will have little or no impact on the RPS and GHG emissions.
12. Significant investments in renewable resources and BESS are required to achieve the 50% renewable portfolio standard and beyond. It is estimated that investments of US$1.3 Billion over the 20-years period, of which US$ 0.84 Billion is required by 2030.
13. Beyond 2030 renewable energy sources will be the dominant source of electricity generation in Jamaica, with natural gas as the only fossil fuel energy source of note.

14. Renewable energy will contribute 49.8% of the energy generated by 2030 thus achieving the RPS target of 50% by 2030.
15. The replacement of the 171.5 MW of thermal plant with like thermal plants will not allow the achievement of the 50% RPS by 2030.
16. Repowering of contract expired wind turbines of over 20-years old technology with new larger modern turbines is a viable option and can increase the capacity of such facilities by 3-4 times, with much improved performance and maximizing the use of valuable proven wind sites. The impact is a lower cost of energy from this method than from unproven greenfield sites.
17. Significant benefits will accrue from the investment in renewable energy investment:
    a. Reduction of GHG emissions from approximately 2.06 million tonnes per annum in 2022 to 1.26 million tonnes in 2030.
    b. Reduction in fuel imports from 5.75 million BOE in 2022 to 3.66 million per annum BOE in 2030 resulting in significantly less dependency on imported fuel will reduce the electricity price fluctuations.
    c. Reduction in the cost of electricity generation if IRP-2 implementation plan is executed according to the planned schedule.
18. The preferred portfolio plan is robust to reasonable changes in the key parameters and assumptions.
19. It is critical to ensure that the implementation schedule milestones are maintained to achieve the stated objectives. In this regard the resource procurement process must be streamlined to allow for expeditious procurement, by developing the institutional capability to manage frequent and multiple resource procurements.

20. Transmission Plan

21. A major shift from the application BESS as frequency regulation to several ancillary services (dispatch-able, virtual transmission line, capacity reserve, contingency spinning).
22. The application of 2-hours BESS versus 45 minutes BESS currently installed at JPS Hunts Bay S/S.
23. The advancement and price reduction in BESS technology have made significant gains in providing opportunities for power grids to satisfy varying operating and planning requirements for increasing RPS.
24. With over 493MW of BESS planned over the 20 years' horizon the price of ESS continues to fall coupled with longer storage duration. The price of BESS is projected to reduce by over 50% by 2030. BESS is therefore shaping to be the transitional technology to reduce Jamaica's dependence on imported fossil fuel.
25. The applications of BESS technology are not site specific and therefore lends itself to several solutions on the transmission and distribution grid to mitigate existing and anticipated violations.
26. The synthetic inertia of the preferred portfolio BESS is adequate to mitigate against the threat of grid instability with the reduction in system inertia due to the displacement of thermal generation with VREs that affect the rate of change of system frequency during disturbances.

27. The grid operator performs a more detailed and comprehensive assessment of the transmission plan to adequately satisfy the requirement of the transmission grid over the medium to long term planning horizon. This will include the technical and economic feasibility and timing for the recommended transmission infrastructure upgrades.

14. Recommendations

It is recommended that the preferred implementation plan of IRP-2 shown in Table 11-2 and which includes the replacement of JPS ROFR 171.5 MW capacity with renewable energy capacity of equivalent energy production, be adopted to guide the future development of the Jamaican electricity system. Timely updates of the IRP planning are recommended to account for changes in key drivers impacting on the electricity sector.

Given the procurement timelines for new generating plant resources it is recommended that the procurement of resources required to be in operation by 2024 - 26 be started by 2023, and for resources required to be in operation by 2026- 2028 be started by 2024, and those resources required to operate by 2028 -2030 be started by 2026.

In this regard we recommend that the resource procurement process be updated and streamlined as a matter of extreme urgency to allow for expeditious procurement of generating capacity. The institutional capability of the generation procuring entity be developed accordingly to manage the frequent and multiple resource procurements that are required.

14.1 Planning Updates and Feasibility Studies

We recommend that:

- The IRP study be updated at least on an annual basis, and a new IRP study carried out every other year given the uncertainties over the long term 20-year planning period and the changes which can and will occur in energy demand forecasts, legislative and regulatory requirements, fuel pricing and technology changes.
- MSETT to develop and rank on technical and economic bases an inventory of suitable sites based on feasibility studies for wind, hydro and solar plant locations, considering the need to have geographical diversity of sites to ensure better renewable energy security, and not too dependent on one geographic location as is the situation today where the wind and solar renewables are predominantly located in the south of the island.

- In order to support the electricity planning function of MSETT and to ensure the harmonized, efficient and secured collaboration of the key sector stakeholders, the suite of existing electricity planning software and models are to be integrated by establishing a MSETT's ICT system/platform. This initiative should be developed and executed as a priority short term action.
- MSETT resource capabilities be developed to keep abreast of renewable energy technologies developments and advances in energy storage technologies, in terms of alternatives, performance, availability and costs. These technologies should include; off-shore wind sites, floating solar plants technology and siting capabilities, hydrogen fuel cell, BESS and small scale nuclear power plant technology, as well as other emerging technologies for energy generation and storage.
- MSETT carry out technical and economic feasibility studies to determine the feasibility of repowering existing proven wind and solar resource sites.
- MSETT to keep abreast of local biomass and waste to energy potential by carrying out technical and economic feasibility studies to enable the development of these projects for market consideration.
- JPS updates the transmission and generation system data base to support the accurate modelling of these systems for power flow, and stability analyses of the power system.
- The OUR update of the Electricity Sector Codes to ensure that the provisions are relevant to the evolving renewable and energy storage technologies, and grid performance requirements.