GOVERNMENT OF THE REPUBLIC OF NAMIBIA

MINISTRY OF MINES AND ENERGY

NATIONAL INTEGRATED RESOURCE PLAN (NIRP) REVIEW AND UPDATE

Final Report

October 2022

Foreword

The 2022 National Integrated Resource Plan (NIRP 2022) update was prepared by the Ministry of Mines and Energy (MME) in collaboration with the Electricity Control Board (ECB) and NamPower and with the support of consultants (Economic Consulting Associates (UK) and Mutschler Consulting Services). The NIRP 2022 updates the previous NIRP prepared in 2016 (NIRP 2016) and covers a twenty-year planning period.

The present document highlights the analysis and findings of the NIRP 2022. The information underpinning the study was obtained and developed from 2020 to 2021 and the pricing information is considered to be up-to-date as of 2021. It will require updates over time to reflect developments in Namibia's Electricity Supply Industry.

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OFFICE OF THE MINISTER
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Tom K. Alweendo, Member of Parliament

Minister of Mines and Energy

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Abbreviations and acronyms

AEMO	Australian Energy Market Operator
AGR	Advanced gas cooled reactor
BESS	Battery energy storage and supply (one of a number of possible energy storage technologies)
BHM	Behind-the-meter
BtE	Bush-to-Electricity
BWR	Boiling water reactor
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CFB	Circulating fluidised bed
CIF	Cost-insurance-freight
CNG	Compressed natural gas
COD	Commercial Operation Date
COUE	Cost of Unserved Energy
CSP	Concentrated solar power
DAM	Day-Ahead Market
DSM	Demand-side measures
ECA	Economic Consulting Associates
ECB	Electricity Control Board
ECC	Environmental Clearance Certificate
ECOWAS	Economic Community of West African States
EE	Energy Efficiency
EIA	Energy Information Administration
EMP	Environmental Management Plan
EPC	Engineering Procurement and Construction
ESEIA	Environmental Socio-Economic Impact Assessment
ESI	Electricity supply industry
EUE	Expected unsupplied energy
FGD	Flue gas desulphurisation
FOAK	First-of- a kind
FOB	Free on board
FPS	Floating plant system
FPSO	Floating plant system offshore
FRSU	Floating Storage and Regasification Units
GCR	Gas cooled reactor
GDP	Gross domestic product
GHG	Greenhouse gas
GHI	Global Horizontal Irradiance
GJ	Giga Joules
GRN	Government of the Republic of Namibia
GT	Gas Turbine
HAWT	Horizontal-axis wind turbine
HFO	Heavy fuel oil
HHV	Higher heating value
IAEA	International Atomic Energy Agency
ICRE	Internal Combustion Reciprocating Engine
IFM	In front-the-meter
INDC	Intended Nationally Determined Contributions
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producers
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan
LCOE	Levelised cost of electricity

LFO	Light fuel oil
LNG	Liquified Natural Gas
LOHEPS	Lower Orange Hydro Electric Power Stations
LOLP	Loss of load probability
LR	Large Reactors
LWGR	Light water-cooled graphite moderated reactor
MCDM	Multi-Criteria Decision Making
MME	Ministry of Mines and Energy
MSB	Modified Single Buyer
MW	Megawatt
N$	Namibian dollar
NDC	Nationally Determined Contributions
NDP	National Development Plans
NEP	National Energy Policy
NERA	Namibia Energy Regulatory Authority
NG	Natural Gas
NIRP	National Integrated Resource Plan
NOAK	nth of a kind
NPV	Net present value
NREL	National Renewable Energy Laboratory
NREP	National Renewable Energy Policy
O&M	Operation & maintenance
OCGT	Open Cycle Gas Turbine
PC	Pulverised coal
PHWR	Pressurised heavy water moderated reactor
PPA	Power Purchase Agreements
PPI	Producer Price Index
PV	Photovoltaic
PWR	Pressurised water reactor
RE	Renewable Energy
RED	Regional Electricity Distributors
REFIT	Renewable Energy Feed-in Tariff
RES	Renewable Energy Sources
RoI	Return on Investment
SADC	Southern Africa Development Community
SAPP	Southern African Power Pool
SMP	System marginal price
SMR	Small modular reactor
SSA	Sub-Saharan Africa
TOR	Terms of Reference
TOU	Time-of-use
TSO	Transmission system operator
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
WB	World Bank
ZAR	South African Rand
ZESA	Zimbabwe Electricity Supply Authority
ZESCO	Zambia Electricity Supply Corporation Limited
ZPC	Zimbabwe Power Company

Price datum

Costs are in constant price terms of mid-2020.

Executive summary

The 2022 National Integrated Resource Plan (NIRP 2022) update was prepared by the Ministry of Mines and Energy (MME) in collaboration with the Electricity Control Board (ECB) and NamPower and with the support of consultants Economic Consulting Associates (ECA) and Mutschler Consulting Services (MCS). The NIRP 2022 updates the previous NIRP prepared in 2016 (NIRP 2016) and covers a twenty-year planning period (2022-2042, though investment plans are shown to 2040).

Some significant changes occurred in Namibia's electricity sector after 2016: (i) the demand growth foreseen in the 2016 NIRP did not materialise as a result of various international developments, (ii) falling costs for solar and wind generation resulted in these becoming commercially viable and penetration of net metering as well as embedded grid-scale projects escalated, which is expected to increase with the implementation of the Modified Single Buyer (MSB) model and the opening of 30% of the electricity market to competition. Following the implementation of the MSB market in September 2019, 452 MW was allocated to be supplied by Eligible Sellers. Of this, 11% (49MW) was licenced by the ECB and, at the time of drafting this NIRP, those projects were in the early stages of development[1].

The implementation of the MSB market model is a significant development for the electricity sector and affects how the NIRP should be interpreted. While in 2016 the "base case" of the NIRP could have been thought of as the recommended investment plan for NamPower, this is no longer true because today a significant part (30% of annual energy consumption) of the power market is open to competition and can be supplied by the private sector. This part of the market is subject to market forces and is not required to comply with the NIRP but shall be subject to regulatory oversight by the ECB. The NIRP is no longer a definitive "plan" for investments by NamPower (or anyone else) but shall now be considered much more **as an analysis that guides policy** by MME while also **providing guidance to NamPower and other investors on least cost investments.** It also provides guidance to ECB when reviewing the efficiency of new IPPs and NamPower regarding cost of generation and other investments.

The updated NIRP provides a set of alternative least cost electricity sector investment planning scenarios dependent on government policy choices (demand-side as well as supply-side measures). The output of the NIRP is primarily a set of short-, medium- and long-term generation investments **that inform Namibia of the generation investments, cost and greenhouse gas consequences associated with alternative policy choices.**

The NIRP 2022 continues to be **focused on the entire grid-connected electricity sector irrespective of whether the identified investments will be fulfilled by the private sector or by NamPower.** The NIRP 2022 is focused on the national electricity market and not on identifying commercial opportunities for exporting electricity directly (e.g., through large solar parks) or through energy products (e.g., hydrogen or ammonia) derived from renewable energy sources (RES). Projects developed primarily for the export market are considered to be private commercial decisions and are relevant to Namibia's IRP only to the extent that some part of those projects may be used to supply the national market. At the time of preparing the NIRP 2022, apart from the Kudu gas-fired power plant, such commercial

[1] NamPower Annual plan – 2021 p69.

projects targeting exports were not sufficiently developed to allow the NIRP to be broadened to consider these explicitly. If or when these become more definite projects the NIRP might need to be updated, though, as discussed later, the findings of the NIRP 2022 are already fully consistent with many of the large-scale projects that are being discussed and would not appear to require an update except for regional planning studies.

Updated load forecast and supply/demand balance

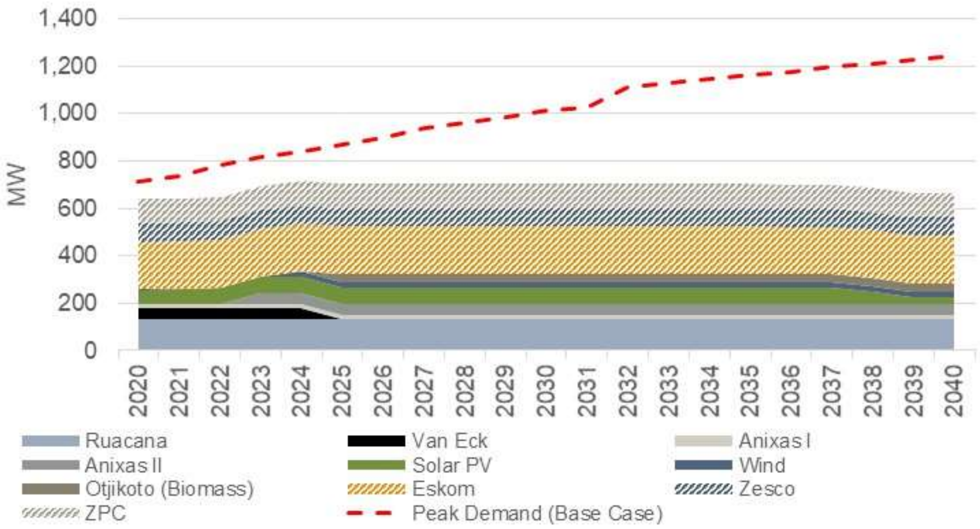
The load forecast is adapted from NamPower's own forecasts of load (MWh) and maximum demand (MW) to reflect the approved electrification access programme, the penetration of behind-the-meter rooftop solar PV and a higher income elasticity.

The forecast is for Namibia's own electricity load and does not consider the potential demand for electricity outside of Namibia that could be supplied with plants from within Namibia. This is not the purpose of the NIRP (though could be part of regional IRP).

The load (GWh) is projected to grow by an average of 2.7% per year over the 20-year period and peak demand at a slightly higher rate of 2.8% per year. The growth rate of load (GWh) flattens off from 2030 onwards as the electrification access programme achieves its goals. A number of large step loads are expected to be developed in the early 2030s which would counterbalance the drop in the growth of load but it is anticipated that they would add more to the peak demand than to the load leading to a slight fall in the system load factor.

Figure 1 compares the firm capacity of existing and committed plants and contracted import capacity with the forecast peak demand to 2040. New additions (Anixas II and renewable power plants listed below) will not be sufficient to close this capacity gap and new plants or import contracts will be required.

Figure 1 Derated existing and committed firm capacity vs. forecast peak demand



Source: ECA. Note, solar and wind are not included in the diagram as they are non-firm[2]

Policy scenarios

Least cost investment sequences were developed for seven policy scenarios as summarised below.

Table 1 Generation least cost planning scenarios

No	Scenario Name	Description
1	**Base case**	A least cost investment plan that is constrained by: • Compliance with the 2017 National Renewable Energy Policy (NREP) to achieve a minimum 70% share of GWh supplied from RES (wind, solar PV, concentrated solar power (CSP), biomass and hydropower) gradually by 2030. • A self-sufficiency target of 80% of primary energy used in power generation – Namibian solar, wind, hydro or gas – within 7 years (i.e., by 2028). In this scenario, power from the Kudu gas-fired export power plant is assumed **not** to be available for the domestic market.
1a	**Base case (+ Kudu gas)**	As for the base case except that some power from the Kudu gas-fired export power plant is assumed to be available to supply the Namibian market at prices that are competitive with imports.
2	**Forced "base-load" power plant**	As for base case except that a 150 MW "base-load" plant is forced in to the investment plan. Other than Kudu, the only option that is available is a 150 MW CSP plant with storage. Other base-load options such as

[2] However, as discussed in the main report, the analysis does recognize that wind will make some contribution to peak demand on a probabilistic basis.

No	Scenario Name	Description
		coal-fired or oil-fired power plants are not available because of Namibia's climate change commitments.
3	**No self-sufficiency target**	As for the base case except that the investment plan is not required to satisfy the 80% self-sufficiency target.
4	**Accelerated RES target**	As for scenario 3 above except that the achievement of the 70% RES target is brought forward from 2030 to 2026.
5	**Large power plant scenario**	In this scenario there are no RES or self-sufficiency targets (i.e., as for scenario (3)) except that that in this scenario it is assumed that the Kudu gas plant will be ready for dispatch in 2026 and 250 MW of the output will be available to Namibia at prices competitive with imports. It is further assumed the 300 MW Baynes hydropower plant would be commissioned in 2031. The timing of Kudu is based on its earliest commissioning date and the timing of Baynes is determined to satisfy the power system's reserve requirement (and system reliability).
6	**Unconstrained**	In this scenario there are no policy constraints.

Source: ECA

A wide range of technologies and energy sources as well as imports were initially considered to close the supply/demand gap in the most efficient way. Some of these options were screened out using conventional techniques described in the main report. Coal-fired generation was screened out because of commitments made by government at the Climate Change Conference in Glasgow in November 2021. The remaining candidates were then subjected to detailed analysis to identify a number of least cost investment scenarios.

Results

The capacity additions, present-valued system-wide costs, and CO_2e emissions for the selected scenarios are summarised in the table below.

Table 2 Capacity additions by scenario to 2040 (MW unless otherwise specified)

Scenario	1	1a	2	3	4	*5*	*6*
Power plants	**Base case**	**Base case (+Kudu gas)**	**Forced base-load plant**	**No self suffi-ciency target**	**Accelerat ed RES**	**Large power plants**	**Uncons-trained**
Hydro	-	-				300	-
Natural Gas	-	200	-	-	-	250	-
LNG	-	-	-	-	-	84[3]	-

[3] 2 x 42 MW open-cycle gas turbines. These units are chosen by the optimization algorithm in order to avoid load shedding in 2025 following the assumed closure of the Van Eck power plant at the end of 2024, and before the commissioning of the Kudu gas-fired power plant in 2026. In practice it

Scenario	1	1a	2	3	4	*5*	*6*
Power plants	**Base case**	**Base case (+Kudu gas)**	**Forced base-load plant**	**No self suffi-ciency target**	**Accelerat ed RES**	**Large power plants**	**Uncons-trained**
HFO	50	50	50	50	50	50	50
Wind	1,546	1,036	1,486	1,546	1,546	586	1,546
Solar	830	960	710	830	830	830	830
Solar CSP		-	135			-	
Biomass	40	40	40	40	40	40	40
Battery	650	550	550	650	650	500	650
Imports	-	-	-	-	-	-	
Total (without committed capacity)	2,850	2,570	2,705	2,850	2,850	2,374	2,850
Total (with committed capacity)	3,116	2,836	2,971	3,116	3,116	2,640	3,116
Present value costs (N$ mn.)	**56,189**	**55,639**	**63,575**	**56,233**[4]	**56,275**	**57,788**	**54,172**
CO_2e (tonnes)	1,436	8,259	1,432	1,418	1,418	10,949	1,436

The least cost investment sequences for all seven of the scenarios point to the attractiveness of solar PV and wind energy technologies, combined with battery energy storage (BESS) as representative of a range of regulated storage options. As described below, Scenarios 1, 3, 4 and 6 all suggest that the technologies with the lowest economic cost would also satisfy and exceed the policy targets of 70% penetration of RES (whether by 2030 or by 2026) and 80% self-sufficiency (by 2028). In other words, it is not necessary to incur additional costs in order to achieve these policy targets. The solar PV and wind resources could be developed by NamPower, by the private sector to supply the national market, or by the private sector to supply the international market with some allocated to the domestic market (e.g., the mega projects). The NIRP does not differentiate between developers.

The investment sequence associated with the base case scenario is provided below. The table below shows the technologies selected as least cost by the optimisation model together

is likely that the closure would be postponed or import contracts would be extended or some other solution would be found to bridge the supply gap in 2025.

[4] The present-value costs should be greater than or equal to those in the base case. The difference of less than 0.1% is within the tolerance of the modelling optimization algorithm.

with the committed plants and the amount of capacity commissioned for each technology in each year.

Table 3 Selected new capacity – base case (MW)

Fuel	BESS	HFO	Kudu	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Natural gas*	*Otjikoto*	***Luderitz & generic plants***	***Khan & generic plants***
2022 - 2030	500	50	-	40	936	730
2031 - 2035	150	-	-	-	330	30
2036 - 2040	-	-	-	-	280	70
Total	650	50	-	40	1,546	830

Source: ECA Analysis

RES energy and self-sufficiency targets are easily satisfied

The analysis confirms that the 70% RES energy penetration target is achieved by 2030 with or without the imposition of policy constraints on Namibia's investment plan. Only if the Kudu gas-fired power plant is developed for export and some of that power is diverted to Namibia (scenario 1a) or if the large power plant scenario (scenario 5) is followed, which also includes Kudu gas-fired power plant, would it be necessary for MME to intervene to ensure that the 70% target is achieved[5].

Because the most economically attractive options available to Namibia generally involve the development of indigenous renewable power, the investment plans generally satisfy the 80% self-sufficiency target even without introducing this as a policy constraint.

Greenhouse gas emissions will be very low

Emissions of greenhouse gases essentially follow the same pattern as RES penetration described above with CO_2e emissions from power generation dropping from already low levels[6] to almost insignificant levels by 2025. The introduction of the Kudu gas-fired power plant in 2026 in two of the scenarios would, however, increase emissions of greenhouse gases associated with Namibian electricity supply[7].

[5] The output of the Kudu gas-fired plant would need to be kept below its capacity in order to satisfy the RES target. The model keeps RES production to this target but in the real world Kudu would need to be instructed to keep its production down.

[6] Relative to many other countries, Namibia's emissions of CO_2e from the power sector are already at very low levels.

[7] Note that this does not include greenhouse gas emissions associated with exported power from the Kudu gas-fired power plant. Such emissions would also be attributed to Namibia in conventional UN greenhouse gas accounting practices and would increase the emissions above those estimated in this analysis.

Policy and investment choices and next steps

When making policy decisions relating to energy security, most countries face trade-offs between sustainability, reliability and affordability. Namibia appears fortunate in having energy resources that allow all of these pillars to be aligned, with the optimisation of least cost energy sources also being environmentally attractive. Because these sources are least cost, they allow electricity to be supplied to users at lower cost than alternatives and are therefore good for Namibia's economy and for end users.

In practice, the need for the investments will depend on how load growth progresses in reality and what demand-side or energy efficiency measures are implemented and what behind-the-meter technologies are adopted by consumers, both of which will impact on how much electricity needs to be supplied by the grid. The NIRP focuses particularly on supply-side measures to serve the national grid, and while behind-the-meter technologies and demand-side programs were not ignored in the load forecast, there will be further opportunities for implementing demand-side measures, such as solar water heating and ripple control on water heaters, that will slow growth in the load and maximum demand. There may also be a gradual switch to electricity in transport, which could increase load growth. Fortunately, the RES technologies identified in the investment plans have relatively short construction periods and this allows the investments to be matched more closely to the growth in load experienced over time, thereby avoiding surpluses and stranded investments that might occur with larger-scale investments that require longer term forecasting. However, even with RES technologies, the lead times and approval processes can be protracted.

The analysis supports the base case scenario as the most appropriate investment plan for Namibia, primarily comprising a mix of wind, solar and energy storage solutions. These investments could be delivered by NamPower or the private sector through the MSB market or under contract to NamPower (the NIRP does not make recommendations regarding the developers). The NIRP leaves open the possibility that these investments could be made as part of export-oriented projects or standalone ones. NamPower, as the "supplier of last resort" as per the MSB framework, is allowed to adjust its generation investments to fulfil its role of ensuring security of supply for the country.

Options relating to the Kudu gas project (representative of export-oriented projects more generally) and the CSP project to provide "base-load" capacity may only be considered when the resulting LCOE is financially sustainable for the end-consumer. Namibia is again fortunate that the modular nature of RES means that RES investments, and associated BESS, may go ahead while further work continues regarding these projects, export-oriented projects more generally, and the potential to absorb intermittent generation is better understood.

A number of large-scale solar or wind projects have been proposed by private developers for export of electricity, hydrogen or ammonia, or to provide cloud storage resources for use internationally. While not modelled explicitly, the generic analysis of wind and solar in NIRP 2022 suggests that the use of some of the electricity produced by these projects to supply Namibia's electricity demand should be economically attractive for Namibia and financially attractive for NamPower and contestable consumers. Clearly, this would depend on the price at which the electricity is offered from these plants.

While analysis shows that BESS should be developed to balance the intermittent RES that has been identified in the NIRP as economically attractive, this should be regarded as representative of energy storage options more generally. Other, better, options may be available to provide similar services.

There will remain some uncertainty over the capacity of Namibia's grid to cope with the high penetration of intermittent solar PV and wind. It may therefore be appropriate for MME, in coordination with NamPower and ECB, to review the grid's resilience in the light of actual experience of wind and solar at annual intervals as the penetration increases over the coming years.

Solar PV can often be located in parts of the network that avoid the creation of transmission bottlenecks and increased transmission losses and, by diversifying the location of solar parks, this will help reduce the impact of intermittent generation. However, there will be concerns over the ability of the transmission grid to transport power from those parts of the country with the best wind energy resources to the load centres. The analysis did not specifically consider the geospatial aspects of new power generation investment, but we note that the co-location of energy storage with wind generation may help resolve constraints on the operation of the networks. Further investigation would be needed to determine the impact on network development costs and transmission losses associated with wind energy investments.

1 Introduction

The 2022 National Integrated Resource Plan (NIRP 2022) update was prepared by the MME in collaboration with the Energy Control Board and NamPower and with the support of consultants (Economic Consulting Associates (UK) and Mutschler Consulting Services (MCS)). The NIRP 2022 updates the previous NIRP prepared in 2016 (NIRP 2016) and covers a twenty-year planning period (2021-2040, though investment plans are shown to 2040).

1.1 History

This is the third NIRP undertaken for Namibia's power sector. MME mandated the previous two NIRPs to the ECB in 2012 and 2016 but, following the introduction of the MSB market, the responsibility transferred to MME for the third NIRP.

Some significant changes occurred in Namibia's electricity sector after 2016: (i) the demand growth foreseen in the 2016 NIRP did not materialise as a result of various international developments, (ii) falling costs for solar and wind generation resulted in these becoming commercially viable and penetration of net metering as well as embedded grid-scale projects escalated, which is expected to increase with the implementation of the MSB model and the opening of 30% of the electricity market to competition.

1.2 Interpreting the NIRP following the creation of the MSB market

The implementation of the MSB market model is a significant development for the electricity sector and affects how the NIRP should be interpreted. While in 2016 the "base case" of the NIRP could have been thought of as the recommended investment plan for NamPower, this is no longer true because today a significant part (30% of annual energy consumption) of the power market is open to competition and can be supplied by the private sector. This part of the market is subject to market forces and is not required to comply with the NIRP. The NIRP is no longer a definitive "plan" for investments by NamPower (or anyone else) but shall now be considered much more as **an analysis that guides policy** by the Minister while also **providing guidance to NamPower and other investors on least cost investments**. It also provides guidance to ECB when reviewing the efficiency of new IPPs and NamPower regarding cost of generation and other investments.

The updated NIRP provides a set of alternative least cost electricity sector investment planning scenarios dependent on government policy choices (demand-side as well as supply-side measures). The output of the NIRP is primarily a set of short-, medium- and long-term generation investments **that inform MME, NamPower and other relevant stakeholders of the generation investments, costs and greenhouse gas (GHG) consequences associated with alternative policy choices**.

A table showing how the NIRP may be used by various parties for the various purposes is provided in Annex A1.

Though the implementation of the MSB market model is a significant development for the electricity sector, the NIRP 2022 continues to be **focused on the entire electricity sector irrespective of whether the identified investments will be fulfilled by the private sector or by NamPower**. The NIRP 2022 is focused on the national electricity market and **not on identifying commercial opportunities for exporting** electricity directly (e.g., through large solar parks) or through energy products (e.g., hydrogen or ammonia) derived from RES. Projects developed primarily for the export market are considered to be private commercial decisions and are relevant to the NIRP only to the extent that some part of those projects may be used to supply the national market. At the time of preparing the NIRP 2022, apart from the Kudu gas-fired power plant, such commercial projects targeting exports were not sufficiently developed to allow the NIRP to be broadened to consider these explicitly. If or when these become more definite projects the NIRP might need to be updated, though, as discussed later, the findings of the NIRP 2022 are already fully consistent with many of the large-scale projects that are being discussed and would not appear to require an update except for regional planning studies.

1.3 How an IRP is prepared

The output of the NIRP 2022 is a set of short-, medium- and long-term generation and demand-side investment scenarios and reflects current and future supply-side and demand-side options to meet future electricity demand in a sustainable, cost-effective and reliable manner while respecting policy constraints.

Least cost generation development plans for any power system are prepared by identifying a set of candidate plants and supply and demand-side options and assessing the present-valued net costs (capital, fuel, and operating costs) of alternative sequences and combinations of investments that satisfy demand over the planning horizon at a given level of reliability. “Candidate power plants” are options and are distinguished from existing power plants[8] (those already commissioned and operating) and committed:

- A **committed power plant** is one for which a contract has been signed or some other commitment has been made that makes it costly in financial or political terms to retract from that commitment.
- A **candidate power plant** is a project with a possibility to enter into operation, but without an agreement to do so. Candidates also include import options or a share of a national plant that may be developed primarily for export.

To be considered as a candidate, a reasonable amount of information must be available on that option, either through project preparation undertaken by NamPower, developers or others or, in the case of generic technologies (e.g., solar PV or CCGT plants using LNG) from international sources.

Screening curves and the LCOEs can be used to compare power plant costs and eliminate choices that are clearly uneconomic. However, electricity systems are complex and require detailed analysis for matching demand and supply to be able to determine the least cost

[8] Retirement dates for existing plants will be assumed.

power sector development plan. Neither LCOE nor the screening curves can fully capture operating constraints, the variability of renewable energy generators, the dynamic nature of load, and other factors.

Dispatch modelling simulates the operation of the power sector at each time interval (typically by hour) for all possible combinations of power generations options given their technical, financial and economic characteristics. The results of each simulation can be used to identify the least cost plan. Dispatch modelling also allows planners to investigate multiple scenarios in terms of generation mixes as well as any other policies or sensitivities. The software used for the NIRP 2022 is ECA's in-house least cost planning model – Wairoa[9].

The results of the dispatch simulation provide information on total capital expenditures; operating costs; fuel costs; emissions; revenues by unit; average, hourly, and regional prices; realised capacity factors over time; and reserve margins, among others.

1.4 Outline of NIRP 2022

The remainder of the NIRP 2022 is organised as indicated below:

Section 2 – provides an overview of the Namibian electricity sector and related market arrangements.

Section 3 – summarises the demand forecast and the load profile that was used for the development of the generation least cost plan.

Section 4 – analyses exiting committed and candidate generation options that were assessed in the least cost generation plan.

Section 5 – reports the least cost planning criteria, policies and parameters that were taken into account for the development of the least cost plan.

Section 6 – presents the least cost generation development scenarios for Namibia and their associated costs and other attributes.

[9] A summary description is provided in Section 6.1 and further details in Annex A3.

2 Context of the NIRP update

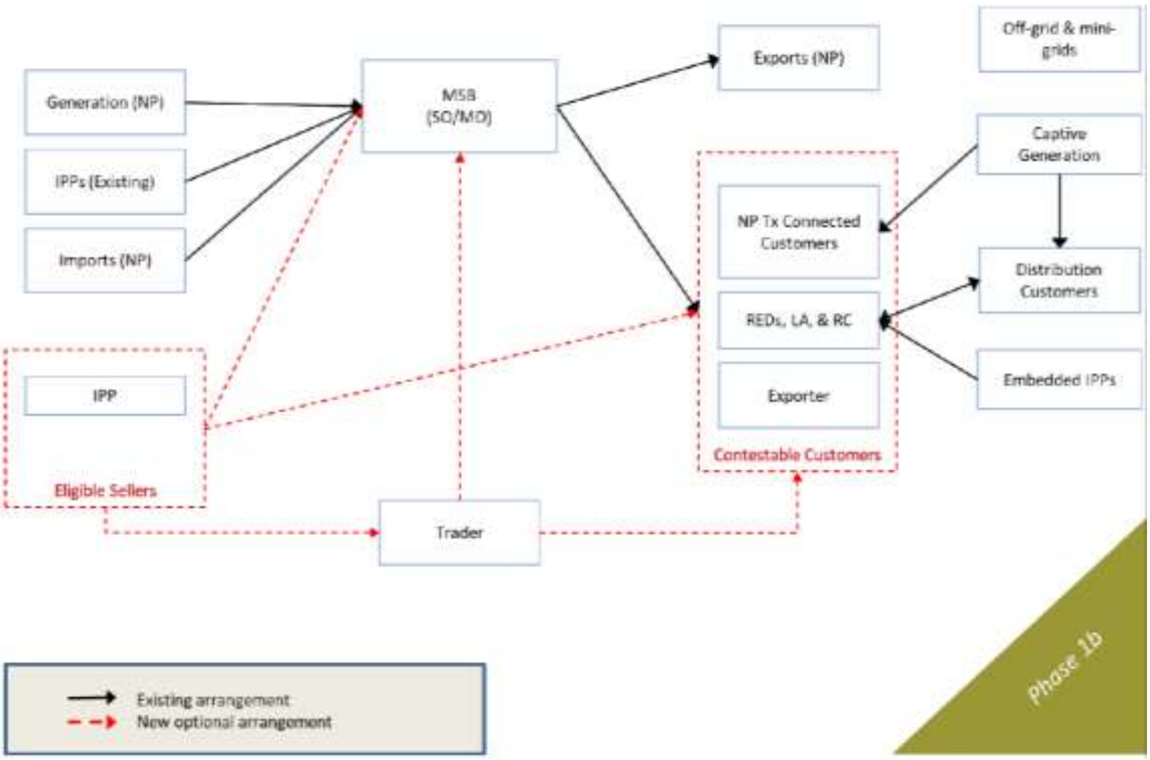
This section provides an overview of the Namibian electricity sector and related market arrangements.

2.1 Market structure

Since 2019, the MSB model has been introduced in Namibia so that some of the market will be supplied directly by independent power producers (IPPs) selling power to contestable consumers over the national transmission network. NamPower acts as the single buyer (under its Energy Trading business unit) for non-contestable customers representing 70% of the market and is also the supplier of last resort for customers in the contestable market. It procures power from its own power plants, from IPPs, and imports through Power Purchase Agreements (PPA). NamPower sells electricity to the Regional Electricity Distributors (REDs), local authorities and its own distribution and transmission connected customers.

Figure 2 shows the MSB model, the key market players and market arrangements currently in operation. Phase 1a as well as phase 1b are currently in operation.

Figure 2 Namibia electricity market structure: MSB phase 1b.



Source: ECB, Detailed Market Design, July 2019

The transmission network (from 66 KV and up) is fully owned and operated by NamPower. Power stations in Namibia are either owned by NamPower, IPPs or co-owned between NamPower and IPPs. The NamPower owned power stations include Ruacana, Anixas and Van Eck. NamPower has a 19% share in the Hardap PV plant near Mariental. All other PV and wind power plants currently in operation are IPP-owned.

There is no Independent Transmission Operator currently established in Namibia. Direct and dedicated interconnections between customers and the transmission assets are sometimes built by the customer, and upon commissioning the asset is transferred to NamPower to own and operate. NamPower must, however, allow third party access to the transmission network by contestable consumers and the IPPs selling to those contestable consumers.

Under the phase 1a of the MSB model, IPPs connected or to be connected to the national grid on transmission voltage levels are allowed to contract directly with transmission customers, supplying up to 30% of their energy demand, subject to available grid capacity. In 2020, 199 MW out of 688 MW of installed capacity was either provided by IPPs under bilateral contracts with contestable customers or with electricity sold by IPPs to NamPower. The remainder of the 688 MW being supplied by NamPower. In the phase 1b (as of June 2021), licenced traders will be allowed to sell and purchase electricity.

2.2 Key market players and roles

The main players in the electricity supply industry (ESI) are the:

- ***Ministry of Mines and Energy (MME)*** – setting out sector policy;
- ***Electricity Control Board (ECB)*** – regulating prices, licences, and the market;
- ***NamPower –*** the national generation and transmission utility – ringfenced into separate business units;
- ***Regional Electricity Distributors (RED)*** = Own, operate and maintain the distribution network and supply to end customers or the local and regional authorities;
- ***IPPs –*** selling power to contestable consumers over the national transmission network.

Namibia power Corporation (Pty) Ltd (NamPower) is the national power company owned by the Namibian Government and the dominant player in the electricity market, responsible for generation, transmission, distribution, and trading of electricity. NamPower is currently the only import and export licensee and is an active participant in the Southern African Power Pool (SAPP). SAPP provides a forum for the contracting and trading of energy between the participating Southern African electricity utilities on a regional day-ahead market – formerly the Short-Term Energy Market (STEM) - and this source of supply is an important option for NamPower.

The role of each player in the electricity market is described in the table below.

Table 4 Key players in the ESI and their roles

Type	Entity	Roles and responsibilities
Government	*Ministry of Mines and Energy (MME)*	Among others, the MME is responsible for the following: developing policies and undertaking planning to ensure national energy security; approval of licences under the Electricity Act, rural electrification planning, funding and implementation, planning for sufficient electricity generation capacity to meet demand, defining procurement and offtake responsibilities for new generation projects
	Ministry of Environment, Forestry and Tourism (MET)	Approval of Environmental Impact Assessments, Environmental Management plans (EMP) and issuing Environmental Clearance Certificates (ECC)
	Ministry of Agriculture, Water & Land Reform (MAWLR)	Rezoning of land and procurement of land for power generation developments
Regulator	*Electricity Control Board (ECB)*	Recommends and implements the ESI regulation and regulatory framework. Assesses licence applications and recommend to MME. Issues, monitors, and suspend licences. Provides regulatory oversight over key agreements including PPA. Recommends tariff level and tariff structure changes.
National utility: NamPower[10]	*NamPower Generation*	Owns and operates current and future NamPower owned plant
	NamPower Transmission	Contains (i) System Operator – responsible for system security and dispatch of generation units to maintain grid integrity in meeting demand; (ii) Supply and Wires – responsible for supplying to a transmission customers; (iii) Network Owner – owns, operates, and maintains the transmission grid.
	NamPower Modified Single Buyer	Includes the Trader and MSB, procuring all power dispatched to the transmission grid, as well as all imports and exports. Responsible for least cost scheduling of supply in meeting demand.
	NamPower Distribution	Owns, operates, and maintain the distribution network in a licenced areas and supply to end customers
IPPs	*IPPs with PPA to supply to the grid*	Owners and operators of generation plant contracted by the single buyer as part of the supply mix
	IPPs with PPAs to end users	Owner and operators of generation plant contracted by end users to supply as embedded generators to the specific end user, no supply to the wider grid
Distributors	*Regional Electricity Distributors*	Own, operate and maintain the distribution network and supply to end customers or the local and regional authorities. Also responsible for rural electrification.

[10] NamPower's business units are ringfenced from one another, meaning that there is some degree of operational unbundling.

Type	Entity	Roles and responsibilities
	NamPower Distribution – see above *Local and regional authorities and other*	Own, operate and maintain the distribution/reticulation network and supply to end customers in areas where REDs are not yet operational, ie in central and southern Namibia.
Customers	*Transmission end users*	Connected to NamPower's transmission network, include large users, REDs, local and regional authorities
	Distribution end users	Connected to a distribution/reticulation network

2.3 Policy

An earlier White Paper and Vision paved the way for the policies in operation today:

- For almost 20 years, a **White Paper on Energy Policy** issued in 1998 provided the overall guidance for the Namibian energy sector.
- Namibia's national development ambitions are guided by the **Vision 2030** document, adopted in 2004, and which presumes secure and affordable energy provided to the country's developing economy and its people.

Today, three policies are shaping future energy investments planning and decision making:

- Government's medium term goals and strategies are expressed in **National Development Plans (NDPs)**. Namibia ratified its contributions to the Paris Climate Agreement, as codified in the **Intended Nationally Determined Contributions (INDCs)** to the United Nations Framework Convention on Climate Change (UNFCCC). Namibia's INDCs commit the country to increase the share of renewables in electricity production to 70% and to increase energy efficiency and demand-side measures.
- The **National Energy Policy (NEP)** The National Energy Policy 2017 sets out the government's short to medium priorities for the energy sector. The main objective of energy policy is to provide "*the security of all relevant energy supplies to the country; to create cost-effective, affordable, reliable and equitable access to energy for all Namibians; to promote the efficient use of all forms of energy; and to incentivise the discovery, development and productive use of the country's diverse energy resources*".

  For the electricity sector specifically, priorities include (i) the development of local generation capacity to improve security of supply through appropriate planning at national level, (ii) reviewing the present electricity market model, (iii) ensuring the on-going viability and development of the transmission and distribution networks and (iv) strengthening the regulatory framework.

- Through the **National Renewable Energy Policy (NREP)** of 2017, the government aims to support renewables expansion. Though not described explicitly as a "Policy Statement", the Renewable Energy Policy states that "*By the year 2030, Namibia shall strive to achieve 70% or more of electricity generated in the country to be from renewable energy sources. The above target relates to electricity (kWh) generated in the country*".

Self-sufficiency goals for the energy sector were identified in the 1998 White Paper and stated Namibia's intention to implement sufficient domestic generation capabilities to meet its own demand altogether with specific targets that 100% of the peak demand and at least 75% of the electric energy demand to be supplied from internal sources by 2010. These objectives were not included in the NEP but remain a goal of the government and expressed in the latest NIRP 2022 as a target to achieve 80% self-sufficiency in the use of primary energy resources for power generation by 2028.

2.4 Licensing framework

The legal framework of the energy sector is set by the **Electricity Act 2007.** It requires the regulator (ECB) to recommend to the MME the issuance of a licence, and the Minister approves the licences (new, suspension or cancellation). ECB approves the PPA tariff of new IPP licences.

Two Bills, currently with Parliament, could significantly impact the development of the electricity market and in particular the procurement and licensing of power generation projects:

- The Electricity Bill, 2017;
- The Namibia Energy Regulatory Authority Bill, 2017 (NERA)

Under the Electricity Bill, ECB will become the Namibia Energy Regulatory Authority (NERA).

The new Electricity Bill sees the introduction of the licensing for the storage of electricity; system operator; and market operator.

3 Load forecast

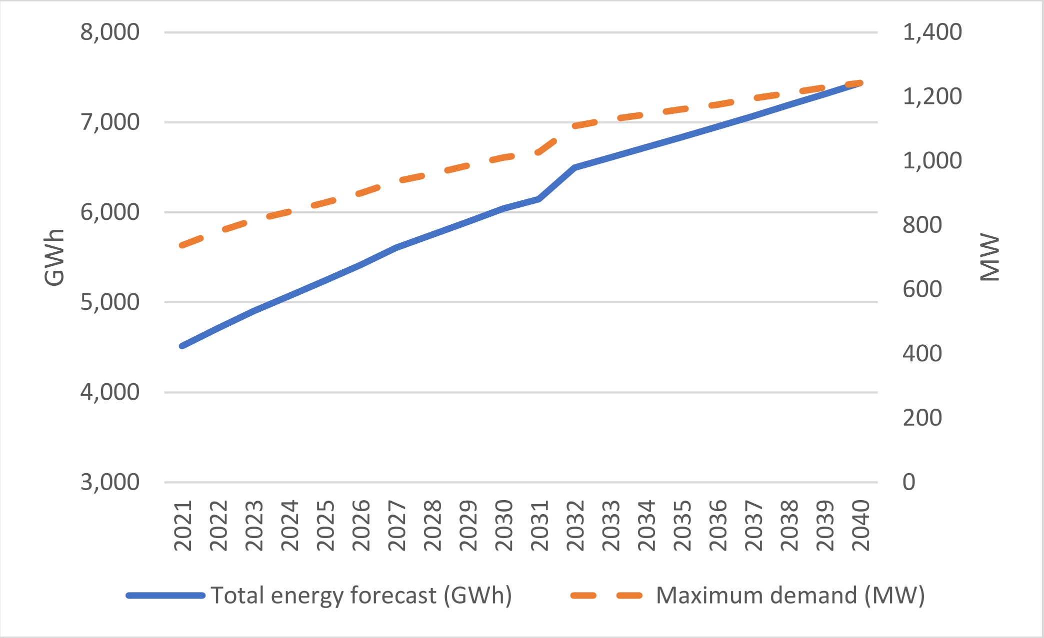
A ‘Load Forecast Report’ was prepared by the Consultant, as part of this study and is attached as Annex A2. The load forecast is adapted from NamPower’s own forecasts of load (MWh) and maximum demand (MW) to reflect the approved electrification access programme, the penetration of behind-the-meter rooftop solar and a higher income elasticity.

Since the 2016 NIRP, the MSB model has been introduced so that some of the market will be supplied directly by IPPs selling power to eligible consumers over the national transmission network. Nevertheless, the present load forecast that is of interest therefore continues to be the national electricity load irrespective of the source of the generation that supplies that load.

3.1.1 Load forecast

NamPower calculates and updates their peak and energy demand forecasts on a yearly basis. These forecasts include three scenarios: base plus step loads with a low, a medium and high probabilities. NamPower’s central forecast comprises 5 years without step loads followed by 5 years of only step loads with a high probability and beyond that the step loads with medium probability. The resulting energy demand forecast represents Namibia’s national load forecast. The figure below summarises the peak and energy demand forecasts used as base case in the 2022 NIRP.

Figure 3 Energy and peak demand forecast



Source: Load Forecast Report

The load (GWh) is projected to grow by an average of 2.7% per year over the 20-year period and peak demand at a very slightly higher rate of 2.8% per year. The growth rate of load (GWh) flattens off from 2030 onwards as the electrification access programme achieves its goals. A number of large step loads are expected to be developed in the early 2030s which would counterbalance the drop in the growth of load but it is anticipated that they would add more to the peak demand than to the load leading to a slight fall in the system load factor.

3.1.2 Low and high load projections

Low and high demand load projections have been prepared to assess the sensitivity of the results to alternative load growth scenarios.

The low projection is based on GDP with growth rates that are 0.75 percentage points lower than the base case while the high load projection has GDP growth rates that are 0.75 percentage points higher than the base case. The low load projection is also based on the assumption of no step loads for 5 years between 2021 and 2025 and only the step loads with a high probability after that. The high load projection assumes the same step loads as the base case. The resulting load forecasts are summarised below.

Figure 4 Load forecast (base, low and high)

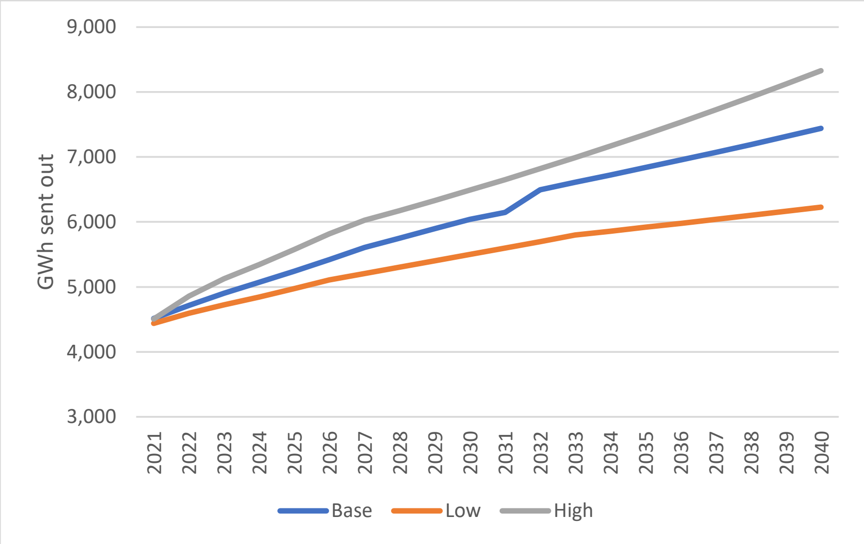
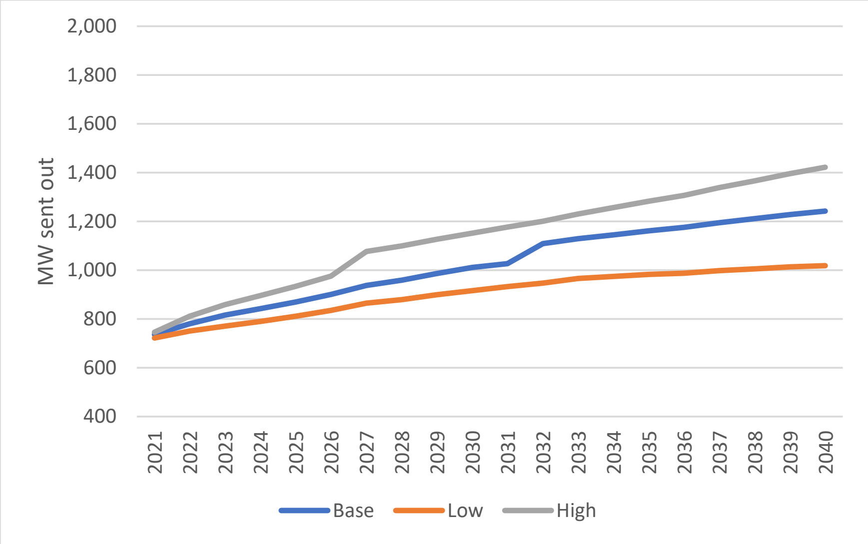


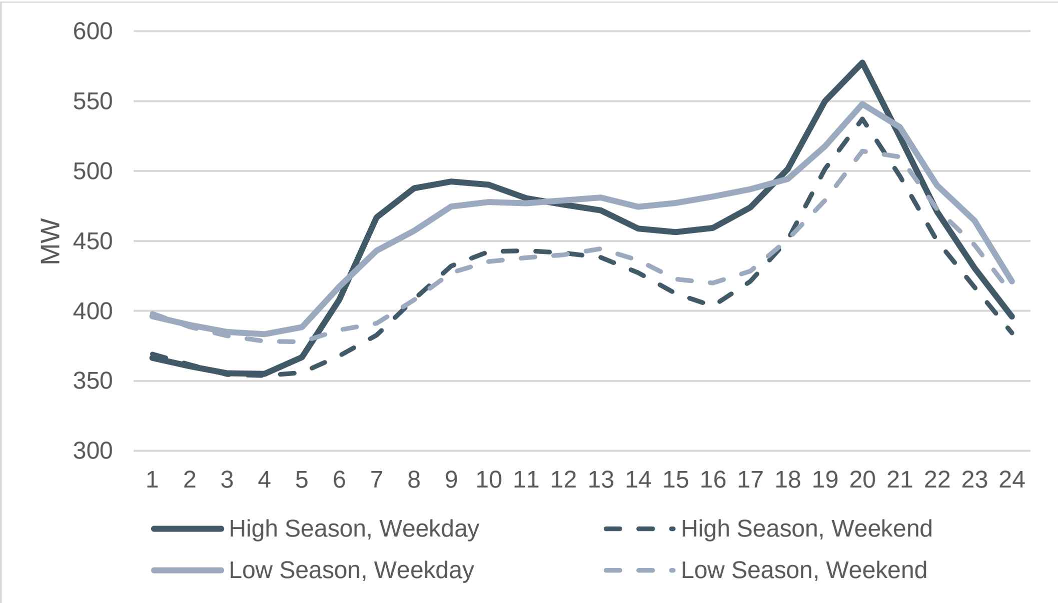
Figure 5 Demand forecast (base, low and high)



3.1.3 Load profiles

Demand in Namibia is influenced by seasons and by time of day. The weekly load profiles averaged demand for the year 2019 as published by NamPower is shown in the figure below. Two seasons are generally defined in Namibia: a high demand season (from June to August) and a low demand season (the remainder of the year).

Figure 6 Hourly load profiles for an average weekday across seasons, 2019



Source: NamPower

The average difference in hourly demand between peak season (July to September) and low season (October to June) is ~5% of peak season demand.

The load shape also shows a 'double-peak' – which is slightly accentuated in the high season. An additional factor of demand variation is day of the week with Saturdays and Sundays generally being at lower levels than weekdays.

This suggests that to model the Namibian system, hourly and seasonal variations need to be considered. If this is not done, the impact of RES intermittency and importantly import costs will be underestimated. Imports from South Africa are priced by season and time of day. To project a reasonable import cost trajectory, hourly granularity of the system is therefore crucial. We intend to model two representative days per week ('weekday' and 'weekend') and for each season of every year until 2040 in order to capture the daily variability of RES production as well as the different import prices with South Africa, against the Namibian load.

Going forward, the shape of the load profile is expected to change. With increasing embedded and 'behind-the-meter' (BHM) generation system-wide demand will reduce. As most of the embedded generation is solar PV, the double-peak phenomenon is likely to become more pronounced.

4 Current supply status and committed plants

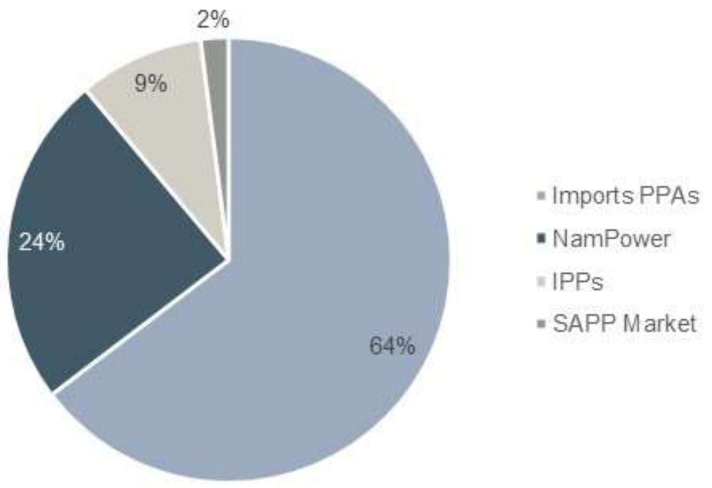
An inventory of the existing power plants and import contracts is provided below together with an assessment of its adequacy to satisfy the forecast electricity load, before considering, in Section 5, the options to be considered for new candidate plants that could be added.

4.1 Existing power plants

Power generation in Namibia is highly dependent on the run-of-river hydro plant at Ruacana and imports from South Africa as well as Zambia. The existing thermal power plants – Van Eck (coal) and Anixas (light fuel oil (LFO)/HFO[11]) - were hardly dispatched in 2021. Van Eck coal plant is old and will be decommissioned over the next years. Anixas still plays a small role in the system as a peaking plant.

NamPower continues to supplement its energy requirements with imports from neighbouring countries in the SAPP region. In 2021 NamPower imported 67% of the total energy requirement from SAPP, Eskom (South Africa), Zambia Electricity Supply Corporation Limited (ZESCO) (Zambia) and Zimbabwe Power Company (ZPC) (Zimbabwe) to meet local demand. The reliance on imports has been steady at around 50% of total requirements throughout the years since 2014. The breakdown of supply is shown in the figure below.

Figure 7 Share of energy produced in 2020



Source: NamPower Annual Report, 2021

[11] LFO used for start-up and HFO used once the engines are warmed up. We assume HFO as the main fuel throughout this report.

Ruacana Hydropower station

The Ruacana hydro power station is located on the Kunene River, in the north of Namibia, where the Kunene River becomes the border between Namibia and Angola.

Ruacana is composed of four units (three units composed of *Westinghouse generators* and *Woest Alpine turbines* with a maximum net output of 85 MW each and one unit of 92 MW composed of an *Alstom generator and Andritz turbine*). All the four units have a minimum power output of 10 MW. While the three 85 MW units were activated in 1978, the 92 MW unit is more recent and was activated in 2012. The station has black start diesel generators and a 330 kV transmission line, running from Ruacana to the Omburu substation, which is some 570 km in length.

Ruacana hydro electric power station was not able to operate at optimal capacity during 2021 and generated a mere 968 GWh of energy, compared to 1,505 GWh in 2020, mainly because of the low seasonal run of the Kunene River. A small dam just upstream of Ruacana allows the power station to produce at its full capacity for eight hours. During the rainy season (from February to May, which corresponds to the low demand season) the station is run at full output level and operated as a base-load power plant, while for the remainder of the year it is operated predominately as a peaking power plant.

The table below gathers all other technical characteristics of the various units.

Table 5 Ruacana technical parameters per units

Parameters	Unit 1 - 3	Unit 4
Technology	Westing house generators and Woest Alpine turbines	Alstom generator and Andritz turbine
Fuel	Hydro run-of-river	
Activation year	1978	April 2012
Maximum operating level (MW)	85 MW	92 MW
Minimum operating level (MW)	10 MW	10 MW
Station auxiliaries	500kW (1Unit) to 700kW (4 Units)	
VO&M charge	0.016 N$/kWh	
Annual Fixed cost	1,020 N$/kW-yr	
Operating regime	Run-of-River, 92% availability	

Source: NamPower

For modelling purposes, the plant will be modelled with a forced outage rate of 4% and planned maintenance of 2 weeks per year for each unit. The plant will be modelled with an hourly generation profile based on observed output (MWh) from the year 2019.

Van Eck coal power plant

Van Eck power station was built and opened in 1972. It is coal-fired with production capacity of 120 MW. Van Eck is located in Windhoek Northern Industrial area. The first two units were commissioned in 1972, the third in 1973 and the fourth in 1979. The plant consumes around 580 kg of coal per MWh of electricity generated and the coal used is imported from South Africa, transported by ship to Walvis Bay and then by rail or road to Windhoek.

Due to various reasons, a maximum of three units can currently be operated at the same time. The station needs external power for start-up. Van Eck power station has a low utilisation factor of only 6.3%. Although under rehabilitation[12], the plant is operated at minimum loads to support and stabilise the transmission network.

The following table presents the expected main parameters of the plant to be used in the NIRP update study.

Table 6 Van Eck technical parameters per unit

Parameters	Value and units
Fuel	Coal
Maximum operating level (MW)	4 x 27 MW[13]
Minimum operating level (MW)	4 x 11 MW
VO&M charge	1.445 N$/kWh
Annual Fixed cost	1,692 N$/kW-yr
Heat rate curve	For one unit: • Load = 11 MW, HR = 19.97 = MJ/MWh; • (Full) Load = 27 MW, 15.81 = MJ/MWh.
Operation regime	41 MW - only 3 x 27MW, 50% availability
CO2e emissions (gCO2/kWh)	993.5

Source: NamPower

Van Eck is modelled as a firm/base-load power plant, producing anywhere between its minimum operating load to its specified operating regime level.

[12] Van Eck Power Station has undergone extensive refurbishment, which started in 2013. Refurbishment activities would result in a useful lifetime extension of the Power Station by another 5 to 10 years according to a study conducted by the USAID in 2012. However, after certain components were opened for detailed inspections, more equipment was found to be in deteriorated condition which resulted in a significant extension in the project timeline (beyond the original completion date of June 2019).

[13] This was the designed maximum operating level. It is not achievable anymore.

Anixas power station

The Anixas power station was constructed as an emergency HFO[14] power station in Walvis Bay. It has an installed capacity of 22.5 MW. It is situated adjacent to the decommissioned Paratus Power Station. It was commissioned in 2011 and had a very low utilisation factor (< 2%). It is used as a standby emergency power plant, as it has a high fuel cost. However, the generating cost per kilowatt-hour is still much cheaper than the cost of not supplying. The technical parameters of the various units are described in the following table.

Table 7 Anixas technical parameters per unit

Parameters	Value and units
Technology	Ley Somer Generator, coupled onto Caterpillar 16M32C Engine
Fuel	HFO
Maximum operating level (MW)	3 x 7.45 MW, Net output: 21.5 MW
Minimum operating level (MW)	30% of full load
VO&M charge	3 x 1.55 N$/kWh
Annual Fixed cost	1,517 N$/kW-yr
Heat rate curve	• 50%, HR = 8.44 MJ/kWh; • 75%, HR = 8.08 MJ/kWh; • 100%, HR = 8.03 MJ/kWh.
Operation regime	90% availability
CO2e emissions (gCO2/kWh)	625

Source: NamPower

Solar PV power plants

Numerous projects have been commissioned in the last five years under IPP contracts and through the Renewable Energy Feed-in Tariff (REFIT) programme. They amount to a total installed capacity of 171.8 MW (223.8 MW with rooftop solar net energy). These projects and their technical parameters are summarised in the following table.

Table 8 Solar IPP plants

Plant list	Activation year	Type	VO&M *(N$/kWh)*	Installed capacity *(MW)*[15]	2019 Output *(MWh)*	2019 Capacity factor (%)
Innosun	01/05/2015	Single-axis tracking	1.53	4.5	12,715	32.2%
Otjiwarongo	2015	Single-axis tracking	1.53	5	n.a.	n.a.

[14] Anixas I uses LFO just for weekly flashing (if running continuously) or when long stoppage is expected. It runs on HFO, which is better priced than LFO or diesel.
[15] This is equivalent to the maximum available power capacity in AC terms.

Plant list	Activation year	Type	VO&M *(N$/kWh)*	Installed capacity *(MW)*[15]	2019 Output *(MWh)*	2019 Capacity factor (%)
HopSol	2016	Single-axis tracking	1.37	5	12,664	28.8%
Osona	2017	Single-axis tracking	1.37	5	15,389	35.0%
Arandis	2017	Single-axis tracking	1.37	3.3	n.a.	n.a.
MetDecci	2017	Single-axis tracking	1.37	5	12,997	29.6%
Aloe	2017	Single-axis tracking	1.37	5	13,113	29.9%
Ejuva One	2017	Single-axis tracking	1.37	5	13,074	29.8%
Ejuva Two	2017	Single-axis tracking	1.37	5	13,689	31.2%
Alcon	2017	Single-axis tracking	1.37	5	15,205	34.6%
Momentous	2017	Single-axis tracking	1.37	5	14,508	33.0%
Camelthorn	2018	Fixed Tilt	1.37	5	6,365	16.0%
Sertum	2018	Single-axis tracking	1.37	5	13,595	31.0%
NCF	01/09/2019	Single-axis tracking	1.37	5	4,357[16]	N/A
Thandii	10/01/2019	Single-axis tracking	1.37	5	3,329[17]	N/A
GreeNam	2018	Single-axis tracking	1.16	20	59,763	34.0%
Hardap	2017	Single-axis tracking	0.87	45	113,610	35.0%
Ohorongo	2020	Single-axis tracking	1.37	7	n.a.	n.a.
Husab	< 2021	Single-axis tracking	n.a.	22	n.a.	35.0%
Unisun	2021	Single-axis tracking	n.a.	5	n.a.	n.a.
Rooftop PV	Existing	Single-axis tracking	n.a.	52	n.a.	n.a.
Total	N/A	N/A	N/A	223.8	N/A	N/A

Source: NamPower

For modelling purposes, as with other intermittent renewable power plants, solar PV plants will generate with a fixed hourly profile. This hourly profile is described in Section 6.5.

Wind power generation

Only the Ombepo wind farm is operating in Namibia. Construction of the N$180 million project started in mid-2016 and it went online in December 2018, generating 5 MW to provide electricity to the nearby towns. The construction of the Ombepo Wind Farm was funded through commercial loans and benefited from the REFIT programme PPAs as offtake arrangement. the REFIT programme and set up by InnoSun Energy Holding, a French-Namibian renewable energy company, in collaboration with the Harbour City of Lüderitz, in southern Namibia. The plant generated with a healthy ~50% of capacity factor in 2019.

[16] Outage since January 2020
[17] Out of operation since January 2020

Summary of existing power plants

Key parameters of Namibia's existing plants are provided in the table below. The main features of Namibia's power generation performance in 2020 are described in the subsequent sub-sections.

Table 9 Existing power generation in Namibia as of December 2020

Plant name	Type	Installed capacity *MW*	Maximum net Output *MW*	Av. 2019 Capacity Factor *%*	Assumed decommissioning
Ruacana	Hydro	347	347	40%	Not defined
Van Ecsk	Coal	128	41	< 2%	2025
Anixas	LFO/HFO	22.5	21.5	< 1%	2,051
Solar PV[18]	Solar PV	223.8	223.8	~30%	n.a.
Ombepo[19]	Wind	5	5	~50%	2043
TOTAL		710	694.5	N/A	N/A

Source: The NIRP Review and Update – Final Report, Power Plants in Namibia January 2016, updated with actual installations and retirements as by February 2020 (Battery energy storage and supply (BESS) Generators characteristics)

4.2 Existing contracts for imports

Imports from South Africa

NamPower has signed an import agreement with Eskom in order to secure power for a pre-defined period and a pre-defined price. NamPower signed a firm PPA in March 2017, which became effective on 1 April 2017 for a duration of five years. As per the agreement, NamPower receives a firm power supply of 200 MW.

The import fees between South Africa were amended and simplified in April 2020: tariffs previously varied by voltage, transmission zone and time-of-use (seasons and hours). They now only vary across load factors and time-of-use.

In order to derive an hourly tariff profile, we calculate an average of the different load factors and capacity and service charges.

We model the import fees of South Africa for the two representative days of each of the seasons on the basis of the following time-of-use figure.

[18] This comprises embedded grid-scale and rooftop PV sites.
[19] Tariffs were also supported through the REFIT programme.

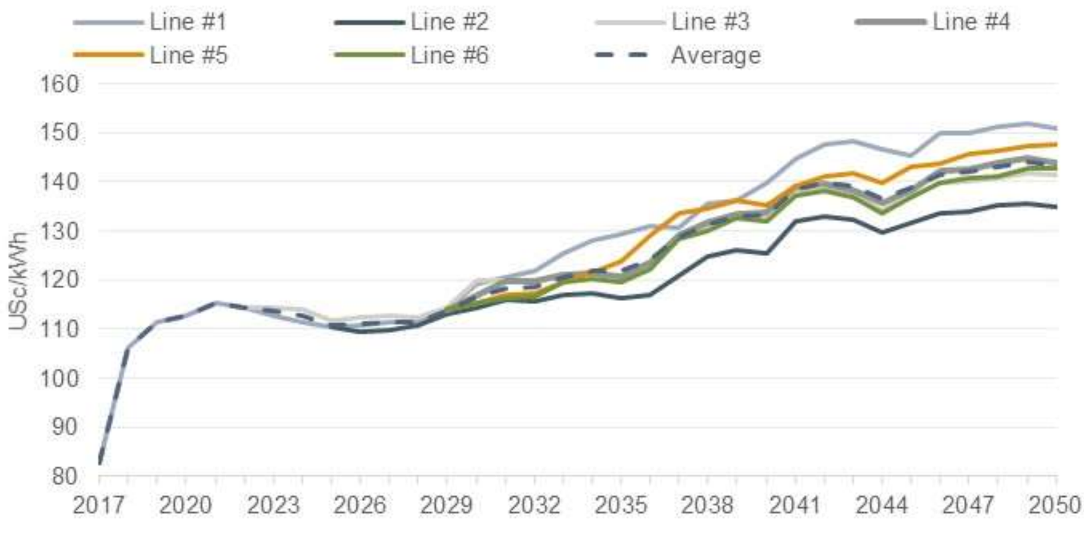
Table 10 Megaflex low and high demand seasons TOU

	High			Low		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
0	3	3	3	3	3	3
1	3	3	3	3	3	3
2	3	3	3	3	3	3
3	3	3	3	3	3	3
4	3	3	3	3	3	3
5	3	3	3	3	3	3
6	1	3	3	2	3	3
7	1	2	3	1	2	3
8	2	2	3	1	2	3
9	2	2	3	2	2	3
10	2	2	3	2	2	3
11	2	2	3	2	2	3
12	2	3	3	2	3	3
13	2	3	3	2	3	3
14	2	3	3	2	3	3
15	2	3	3	2	3	3
16	2	3	3	2	3	3
17	1	2	2	2	3	3
18	1	2	2	1	2	2
19	1	3	3	1	2	2
20	2	3	3	1	3	3
21	2	3	3	2	3	3
22	3	3	3	3	3	3
23	3	3	3	3	3	3

Source: Eskom's schedule of approved tariffs (2020)

The South African Minister of Energy produced a National Development Plan in 2019. The goal of this was to identify and plan future South African investment in the network until 2050. This report builds up around six scenarios that represent the most likely evolutions of the electricity market and infrastructure. Each of these scenarios forecast electricity prices until 2050. We model increase in Eskom tariffs along one scenario that represents the most likely development of the South African market on basis of this IRP of South Africa. The prices projected for the South African system are showed in the figure below (Line #1 to #6).

Figure 8 South African power prices



Source: Department of Energy, South African IRP 2019

Based on these price profiles, we use the annual growth rate of the average of the six scenarios to project South African import prices. We start from current Megaflex import prices (2020/2021 import fees) to obtain import tariffs on a seasonal and hourly basis. Imports into

Namibia are constrained only by the existing combined interconnector capacity of 200 MW. This implicitly assumes that South African imports are always available.

Imports from Zambia

ZESCO determined fixed tariffs for electricity exported to Namibia. NamPower received firm supply of 39 MW from 2010 to the end January 2018. The capacity increased thereafter to the contracted 50 MW after the Force Majeure declared by ZESCO in 2015 due to drought was lifted. The power supply agreement came into effect on 16 January 2010. It has 10-year duration and a firm capacity of 50 MW, which expired on December 31, 2020.

In 2020, new tariffs were negotiated with ZESCO and came into effect from the 2 February 2020. On the basis of information provided by NamPower, we assume a 100 MW base-load firm supply for a duration of 10 years with a commitment of 70% uptake of energy in a billing period (monthly). No capacity payment and a flat tariff (not time-of-use based) are applied. The contract sets up a tariff of 8 USc/kWh (real term, 2020), which is indexed annually on 1 February with the USA Producer Price Index (PPI).

Imports from Zimbabwe

ZPC, a subsidiary of Zimbabwe Electricity Supply Authority (ZESA) (the national utility of Zimbabwe) continued supplying NamPower with 80 MW firm power. This is a source-based supply, stemming from the Kariba Hydro power plant. The contract will expire on March 31, 2025. Both capacity and energy costs are paid in two currencies: 80% is paid in US$ and 20% paid in ZAR. The resulting weighted energy tariff for this contract is N$ 449.8/MWh. Tariffs are also indexed annually on the 1st of February with the USA PPI.

Table 11 ZPC imports Tariffs

Tariff	US$	ZAR	Weighted total
Capacity (kW)	33.58 US$/kW/month	107.15 ZAR/kW/month	483.17 N$/kW/month
Energy (kWh)	3.13 US$c/kWh	9.98 ZARc/kWh	44.98 N$c /kWh

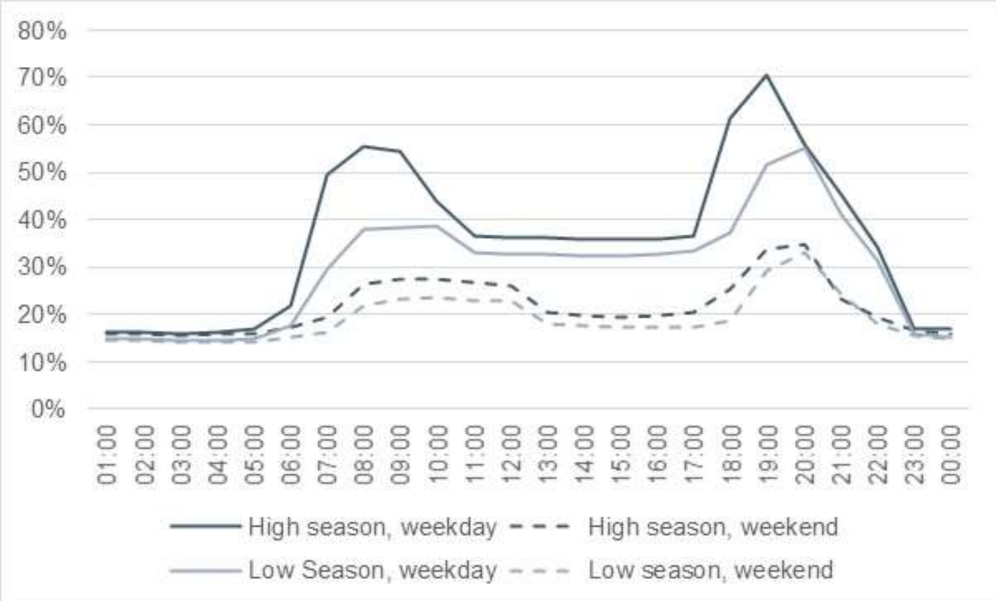
Source: NamPower

Imports from, and exports to, the SAPP Day-Ahead Market (DAM)

NamPower supplements its energy demand requirements by sourcing additional power of up to 100 MW on the SAPP's DAM. Instead of curtailing renewable energy in the unlikely event of excess energy, NamPower can also sell energy up to 100 MW on the SAPP DAM.

The hourly profile of the SAPP DAM prices is based on average prices since the start of the pool market. The profiles for the different seasons and days are presented below.

Figure 9 SAPP DAM hourly price profiles

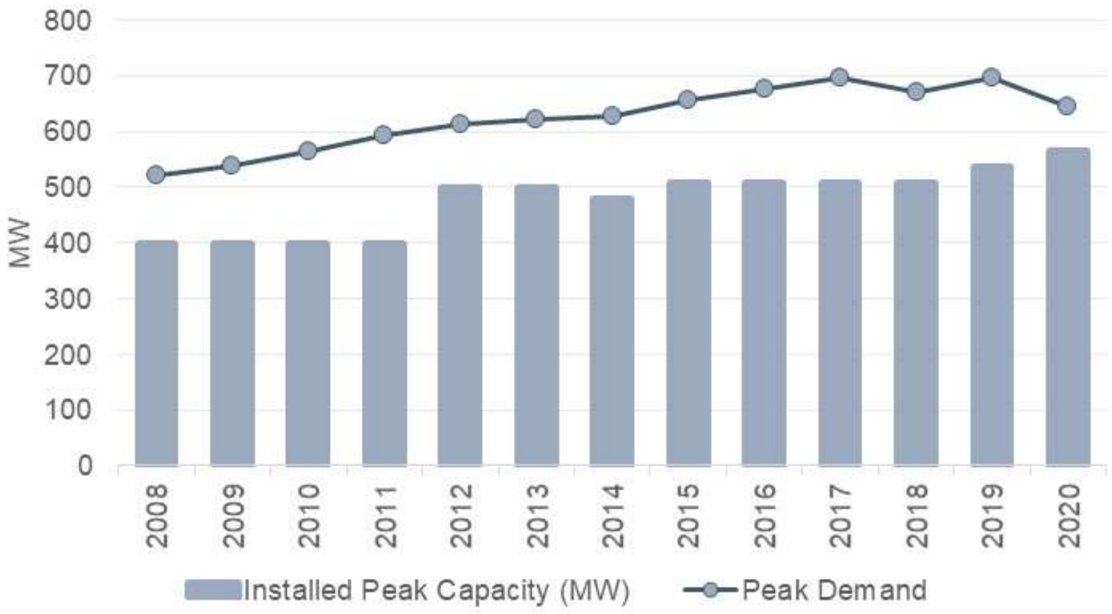


Source: Based on average hourly DAM SAPP prices (from 01/04/2015 to 31/12/2020)

4.3 Existing capacity vs peak demand

In addition, the annual peak demand for electricity in Namibia surpassed the installed local generation capacity as shown in the graph below. The demand started to surpass the installed generation capacity from 2006 and the gap has continued to grow annually.

Figure 10 Namibian Installed capacity and peak demand 2008-2020



Source: ECB

While the installed generation capacity remained constant, with no new investments and/or existing plant refurbishment the peak demand grew with a 3.8 % from 608 MW in 2016 to 630 MW in 2017 but returned to a lower level (602 MW) of peak demand in 2018 amid negative economic growth. This mismatch in demand and generation capacity is exacerbated by the fact that the transmission system is showing high losses of close to 11%. Peak demand registered a 3.5% growth in 2019 as the economy went back up. In 2020, peak demand then registered the biggest drop since 2008 with a -7.4% year on year change.

Load shedding due to supply shortages is however virtually non-existent in Namibia due to the country's strong interconnections with neighbouring countries and heavy reliance on electricity imports.

5 Generation resources and options for new plants

The following sub-sections discuss energy resources available in Namibia together with options for new power plants to satisfy the gap between demand and supply. The NIRP starts by describing the primary resources available and then discusses power supply options that are not yet committed but that have been proposed by various parties including NamPower, government or private investors.

5.1 Primary energy resources for power generation

This section of the report presents a brief outline of each of the primary resources selected to meet the electricity demand in Namibia.

5.1.1 Coal

Coal potential exists in extensive sedimentary basins such as the Owambo, Huab, Waterberg and Aranos basins. The Aranos basin has been investigated in detail for coal and contains in-situ resources of about 350 million tonnes of high-quality metallurgical coal at a depth of up to 300 m, which makes it the largest known coal deposit in the country.

Coal deposits in Namibia have however not been commercially exploited. All coal used in the country is imported from either South Africa or other countries. Large coal mines are already exploited in neighbouring countries (South Africa and Mozambique are ranked 7th and 10th biggest coal exporting countries in the world), making an investment in a new extraction site within Namibian borders unattractive amid a pre-existing oversupply in the Southern African region. South Africa exports about 30% of its coal production mainly through the Richards Bay Coal Terminal, making the country one of the top coal exporting countries in the world. Coal supply to a power plant in Namibia could be secured through a long-term coal supply agreement with one or more coal mines from South Africa or Mozambique.

5.1.2 Indigenous gas resources

In Namibia, the Kudu offshore gas field was discovered in 1974 by Chevron. It has changed hands several times[20]. It is estimated to contain 1.3 TCF of proven natural gas reserves[21]. It is located approximately 130 km offshore to the south-west of the city of Oranjemund in the southwestern corner of Namibia. The gas field is located about 4.5 km underground and would require an undersea pipeline to reach the shore. BWEnergy (formerly BW Offshore) took a 56% operated stake in the project in February 2017, leaving Namcor (the national oil company) with 44%. The stake taken by BW Energy revived the proposed 420 MW project, which would be based on three wells with production over 25 years.

[20] Gazprom exited the project in 2012 followed by Tullow Oil in 2014 and partner Itochu in 2015.
[21] Information provided by BW Kudu in comments on the Draft NIRP, in March 2022.

5.1.3 Imported natural gas and Liquified Natural Gas (LNG)

Natural gas is commercially extracted from oil fields and natural gas fields. Gas production and consumption registered record-high volumetric increases in 2018[22]. Production increased by 5.2%, the highest rate since 2010 and more than double the 10-year average growth rate of 2.3%. US (86 bcm) and Russia (34 bcm) accounted for almost two-thirds of global growth. Similarly, gas consumption increased by 5.3%, with the US (78 bcm) registering the strongest growth on record. China also saw above-average growth of 17.7% (43 bcm). The three countries with the largest proven reserves are the Russian Federation (38.9 Tcm), Iran (31.9 Tcm) and Qatar (24.7 Tcm).

Natural gas produced from a particular well will have to be transported to reach its point of use. The natural gas can either be transported through a complex network of pipelines or through LNG shipment or trucks. Storage capacity of natural gas on consumption point is also a key component of the total supply chain.

LNG ships transport LNG across continents, while tank trucks can carry liquefied or compressed natural gas (CNG) over shorter distances. Ship borne regasification equipment can also be used. Internationally, LNG is the preferred form for long distance, high volume transportation of natural gas, whereas pipeline is preferred for transport for distances up to 4,000 km over land and approximately half that distance offshore.

Global LNG trade[23] surged 13% year on year in 2019 to 354.7 Mt. While a slowdown in growth of LNG trade occurred in 2020 to around 3%-3.5% ahead of a recovery to growth of 6.5%-7% in 2021 and growth is projected to slow to around 1.5%-2% per year, driven by a slowdown in new LNG capacity. There are several operational liquification plants operating in Africa (Algeria, Angola, Egypt, Equatorial Guinea, Libya, and Nigeria), while others are under construction[24].

5.1.4 Fuel oil

Crude oil is extracted from oilfields and is then converted to more refined products in large oil refineries including gasoline, diesel oil, heavy fuel oil (HFO) and Petcoke. Most of the liquid petroleum products can be used to generate electricity by using a variety of technologies. Namibia does not have indigenous oil reserves but fuel oil is imported.

5.1.5 Uranium

It is estimated that some 6.1 million metric tonnes of uranium ore reserves are economically viable around the world[25]. The worldwide production of uranium in 2019 amounted to 54,752 metric tonnes. Kazakhstan produces the largest share of uranium from mines (42% of world supply from mines in 2019), followed by Canada (13%) and Australia (12%). Namibia was the

[22] BP Statistical Review, 2019
[23] S&P Global, July 2020
[24] Some of the biggest projects in 2020 include: Tanzania Liquefied Natural Gas Project (TLNGP), Mozambique’s Rovuma LNG project, Ogidigben Gas Revolution Industrial Park (GRIP) in Nigeria, Mozambique LNG Project
[25] World Nuclear Association, 2017.

fourth largest uranium with 10% of world production. Namibia has two of the ten largest uranium mines sites in the world, Husab and Rössing with respectively 6% and 4% of total uranium production. Namibia's annual uranium output has drastically increased from 2016 due to MME issuing a number of new uranium mining licences.

Uranium ore is mined in several ways, open pit, underground, in-situ leaching, and borehole mining. Commercial-grade uranium can be produced through the reduction of uranium halides with alkali or alkaline earth metals. Namibia's mines two biggest mines are both open pit.

5.1.6 Solar and wind resources

Namibia is blessed with substantial solar and wind resources. Namibia benefits from a very high number of annual sunshine hours and offers one of the highest solar energy yields in the world, with an average high direct insolation of 2,200 kWh/m2/a and minimal cloud cover. The southern parts of the country easily experience up to 11 hours of sunshine per day and recorded direct solar radiation of 3,000 kWh/m2/year. Solar water heaters, solar photovoltaic technologies, and concentrated solar power plants can contribute to reduce the country's electricity supply gap.

Namibia has very favourable wind conditions with long coastlines measuring 1,572 km. Namibia's Lüderitz region wind farm can reach average annual capacity factors as high as 50%.

5.1.7 Hydropower

Namibia's hydropower resource potential is described in relation to two specific candidate projects on the Orange and Okavango Rivers in Section 5.3.

5.1.8 Biomass

In accordance with the EC 2009 RES directive on the promotion of the use of renewable energy sources, biomass is defined as: *The biodegradable fraction of products, wastes and residues from organic farming (animal and plant substances), forestry and assimilated industries, fishing, crops and municipal and industrial wastes*.

Namibia has abundant biomass resources in the form of encroacher bush, which is located primarily in the north-central and central regions. It has been estimated that there are approximately 45 million hectares of bush-encroached land in Namibia[26]. Studies have assessed that this volume of bush resource is commercially sustainable for multiple uses, including Bush-to-Electricity.

There are three relevant to Bush-to-Electricity (BtE) felling operations noted, shear-excavators, bush-dozers and bush-rollers. These felling operations render widely differing environmental impact. Bush-dozer and bush-roller operations are very efficient and cost-effective. Various types of biomass processing equipment are in use, sourced from the USA

[26] Second National Integrated State of the Environment Report for Namibia (ISOER)" published by the Ministry of Environment, Forestry and Tourism (MEFT), September 2021.

and Europe. The harvesting processes currently in use produce according to a large range of hog fuel dimensions specification. Such hog fuel has found a market with Ohorongo Cement and the Namibian Breweries respectively. Haulage distances from the fuel processing sites to Ohorongo Cement are deliberately kept at a maximum of approximately 50 km.

Harvesting regulations are straightforward in Namibia. Compliance with the ECC and the EMP is mandatory for the construction and operation phase of a biomass electricity project.

Bush regrowth happens after the initial harvest, regardless of the harvesting method. The rate of regrowth is influenced by several factors, such as rainfall, soil type as well as harvesting and ‘aftercare’ method. A range of aftercare options exists, with suitability dependent on various factors. Payment for aftercare services is challenging for resource owners and harvesters.

5.1.9 Geothermal

The previous NIRP reported that there are only 12 heat flow measurements in Namibia, mostly from the Damara Belt, and this and the scarcity of data in adjacent regions results in an incomplete heat flow pattern. Despite the region presenting the high average heat flow (69±10mW m-2), the thermal gradients are not exceptionally high and exceed 25 K km-1 at only three localities.

Hot water or thermal springs in Namibia are known in Warmbad, Rehoboth, Omburo (near Omaruru) and Gross Barmen (near Okahandja) but they are used for tourism purposes. Preliminary calculations for the Windhoek and Omburo springs indicate that they probably rise from depths of 2 to 3 km and reach temperatures somewhere between 70 - 80 °C. Drilling into the springs at Grosse Windhoek in the 1920s however caused them to dry up, so the recharge rate of the springs is also of concern.

The previous NIRP has already shown that there is currently insufficient data relating to geothermal gradients, heat flow patterns and other information relating to hot spring reservoirs to make a sound scientific assessment of the geothermal potential. No additional feasibility study have been conducted since its publication: heat flows coverage and springs thermal characteristics remain largely unknown in Namibia.

Given relatively the success of existing geothermal electric plants in other sub-Saharan Africa (SSA) countries (eg Naivasha Kenya), one could see a scenario in which such plants could be funded through a government-private sector initiative or by an IPP. Such geothermal electric plants would then be connected to the national grid and provide a clean and relatively affordable energy source.

However, further investigations of the hot springs in Windhoek and Omburo would need to be undertaken to establish the depth and extent of the reservoirs, their temperatures and water content and the recharge rates. Many preliminary steps can be identified ahead – these steps could take up to 10 years:

- Review of previous studies on geothermal resources, collection of the information related to the geothermal energy resources, critical assessment of the available data;

- Selection of sites for potential geothermal power plants and Investigation of the geothermal potential for each of the selected sites through reconnaissance, drill, testing, etc.

- Carry out prefeasibility studies for the selected sites to estimate the potential output, required investment and operation & maintenance (O&M) costs.

Additionally, considerable government engagement would be required to finance, coordinate, and evaluate these research activities, making geothermal projects commissioning very unlikely during the planning horizon. For these reasons we do not propose to examine geothermal in the detailed generation planning analysis.

5.2 Committed power plants

In this section we describe power generation projects which can be treated as committed. A committed power plant is one for which a contract has been signed or some other commitment has been made that makes it costly in financial or political terms to retract from that commitment. This would include private projects as well as projects to be undertaken by NamPower.

In 2018, NamPower drafted its business plan for the period 2019-2023. Following this business plan, potential generation projects for commissioning were identified. MME later approved the implementation of identified generation projects under the “Strategic Pillar, Ensuring Security of Supply”. It was decided that 220 MW of power generation should be developed of which: (i) 150 MW would be allocated to NamPower and (ii) 70 MW would be allocated on a competitive procurement basis as per current government procurement laws to IPPs for implementation.

The NamPower Board ratified the implementation of the following projects as part of NamPower’s 150 MW allocation:

- 20 MW solar PV project (Omburu).

- 40 MW wind project (Lüderitz).

- 40 MW biomass power project. The site was later identified to be the Otjikoto Biomass power plant.

- 50 MW firm power project. This capacity will be met through the development of the Anixas II Power Station.

5.2.1 Anixas II

The project entails a 50 MW power plant utilising either Internal Combustion Reciprocating Engine (ICRE) or Gas Turbine (GT) technology with liquid fuel (HFO) or compressed fuel

(LNG/CNG) as fuel options[27]. The lifetime is assumed to be 25 years. The total investment is estimated N$ 1.4 billion and the project completion for the power station is planned for February 2022.

The power station will be owned and operated by NamPower, and its purpose will be to ensure that dispatchable power is available to supply emergency power to the Namibian grid during times of shortage within SAPP and to help minimise or avoid load shedding. This power station will therefore be required to have fast start-up and shutdown capabilities (within minutes) and to be dispatched in cases of renewable Energies intermittency events and thereby indirectly support Namibia's commitments to increase their share of renewable energy.

It is anticipated that Anixas II Power Station will only be dispatched when the tariff is less than the cost of energy available in the market, during planned outages of backbone lines, or during emergencies. Hence, the dispatch could be during the morning and evenings peak time-of-use periods only, leaving it with a capacity factor of less than 10%.

NamPower's Walvis Bay site is situated on the border of an industrial area, adjacent to the recently constructed Bulk Fuel Storage facility. The nearest receptor, Kuisebmond residential settlement, lies ≈ 170 meters, northeast of the site. The selected site is presently home to two ICRE power stations, namely Anixas I power station, commissioned in 2011, and Paratus Power Station, commissioned in 1976.

Table 12 Anixas technical parameters per unit

Parameters	Value and units
Technology	ICRE
Fuel	HFO, Diesel, Natural Gas (NG)
Planned activation- decommissioning year	2022 - 2047
Maximum operating level (MW)	50 MWe (net) 3x18MW / 4x13MW
Minimum operating level (MW)	20% of the full load
Capex	N$ 1,004,305,936
Grid costs	N$ 2,500,000 (included in capex).
VO&M charge	N$ 168 / MWh
Annual Fixed cost	N$ 525 / kW / year
Heat rate curve	8.18 GJ/MWh
Operation regime	Peaking unit, capacity factor of < 10% per year
CO2e emissions	625

Source: NamPower

[27] NamPower Anixas II Fact Sheet, June 2020

5.2.2 Otjikoto biomass power plant

Namibia has abundant biomass resources in the form of encroacher bush, which is located primarily in the north-central and central regions. NamPower decided to capitalise on these resources and approved the implementation of new renewable generation projects in June 2018 under the Strategic Pillar, 'Ensuring Security of Supply'. In November 2018, NamPower ratified the implementation of the 40 MWe Otjikoto Biomass power station. The proposed power station is developed as an Engineering Procurement and Construction (EPC) project and will be owned and operated by NamPower where the majority of the costs for the project will be funded from NamPower's balance sheet.

The use of this biomass fuel will complement government policies aimed at combating land degradation from bush encroachment and creating viable rural employment opportunities (Harambee Prosperity Plan and NDP5). The biomass power plant is also listed in Namibia's NDC (2021) targets for climate change mitigation as a replacement for importation of fossil fuels.

The NamPower project fact sheet[28] describes the project site which is owned by NamPower and measures ±44 hectares, it is located within the Oshikoto Region of Namibia, along the B1 national road, close to the existing NamPower Otjikoto Substation. Injection of generation at this node of the grid will contribute to system stability and reduction of losses in the increase in load in the northern areas of Namibia.

The power plant boiler will use grate fired technology (i.e., moving grate, step-grate, vibrating grate, chain grate or travelling grate) favouring a broader fuel specification. This will allow the boiler to burn a larger wood chip particle size and therefore ensure a lower fuel price as opposed to a fuel specification that requires significantly more processing.

The plant can contribute some ancillary services to the system operator. The non-baseload dispatch requirement will lead to lower overall efficiency of the plant, increase maintenance costs and auxiliary requirement in parasitic load.

The power plant can accommodate a hog fuel specification in the order of P100/125 (100 mm and 125 mm), with attention to limits on fines and exclusion of alien contaminants. As a result of the type of bush in the area feeding the power station, lower calorific value, and higher ash content than in other regions might be inherent in the fuel delivered.

Currently, technical specifications for either one or two boiler configurations are under development, namely: 1 x 40 MWe boiler and 2 x 20 MWe boilers. Both the boiler configurations will feed into a single steam header and power block (turbine and generator) to maintain the economies of scale. The biomass wood chips will be used as fuel for the combustion process in the boiler to produce steam that will drive the steam turbine and the electrical generator.

The table below gathers the technical specifications that will be used for modelling purposes.

[28] Otjikoto Biomass Power Station Project Fact Sheet, June 2020.

Table 13 Otjikoto Biomass technical parameters per unit

Parameters	Value and units
Technology	Grate fired boiler
Fuel	Namibian Encroacher Bush Wood Chips
Planned activation- decommissioning year	2024 - 2049
Maximum operating level (MW)	40 MWe (40MW unit or 2x 20MW units)
Minimum operating level (MW)	35%
Capex[29]	N$ 2,679,002,828
Grid costs[30]	N$ 15,500,000 (included in capex).
VO&M charge	N$ 116 / MWh
Annual Fixed cost	N$ 1,785 / kW / yr
Heat rate	14.7 MJ/kg - 12.4 GJ/MWh
Operation regime	Base-load, capacity factor ~70%

Source: NamPower

5.2.3 Solar projects

Considering Namibia's abundant solar resource coupled with the objectives set out in the previous NIRP as well as NamPower's strategic roadmap to expand the penetration of renewables within the energy mix; PV power plants are considered ideal for providing energy at competitive tariffs in Namibia. NamPower is thus advancing the development of its proposed Omburu 20 MW PV power plant. Moreover, the Khan solar project has a signed PPA and is therefore accounted as committed project. This brings the total solar committed capacity to 40 MW.

The Omburu 20 MW solar PV[31] site was selected through a comprehensive study focusing on the need for generation capacity closer to the load centres while reducing the load on the transmission backbone. A Multi-Criteria Decision Making (MCDM) process was used to rank the eight best sites. Although optimum solar resources in terms of Global Horizontal Irradiance (GHI) for PV are located in western Namibia, the Omburu site still presents a substantially satisfactory solar resource and was chosen as the overall preferred site.

The Omburu PV power plant will be developed, owned, and operated by NamPower, where NamPower will appoint an EPC contractor to construct the power plant. The EPC cost released to the public was in the range of N$ 320 million while NamPower's budget estimate was N$ 400million and is classified as Class-D cost estimate, accurate to -20% to +30%. The project technical parameters and site description are presented in the below table.

[29] The capital cost is not relevant for committed plants but will be relevant for candidate plants. The subsequent analysis also considers additional biomass plants as candidates.
[30] As for footnote 29.
[31] Omburu 20MW solar PV Project Fact Sheet

Table 14 Omburu PV power plant technical parameters

Parameter	Value	Parameter	Value
Site area	300 hectares	Plant capacity	20 MW (net)
Coordinates	21°29'21.36"S; 16° 1'14.53"E	Planned Commissioning	March 2022
Plant footprint	40-58 hectares	Performance Ratio	~77.5% (minimum)
Plant lifetime	25 years (minimum)	Capacity Factor	~36% (expected)
PV module Technology	Silicon Crystalline	DC/AC ratio	1.3 (minimum)
PV mounting structure	1-axis back-tracking	Contractor's (EPC) Price – N$	N$ 400,000,000
MOR	3%	Contractor's (EPC) Price – kWnet	N$ 20,000,000
FOR	3%	F&OM	N$ 434

Source: NamPower, Omburu Project Fact Sheet, 2018

5.2.4 Wind projects

Namibia is also endowed with large wind potential. The Namibian west coast has good wind resources, with annual average wind speeds ranging from 6 to 12 meters per second with a potential capacity factor from 30% to 40%[32]. The Walvis Bay area has also been identified as having considerable wind potential, with average wind speeds ranging from 7 to 12 meters per second and an estimated total potential capacity of 25 MW. The north corridor between Walvis Bay and Henties Bay also has considerable wind potential for power generation.

Ultimately, four wind farms (with a total of 98 wind turbines) located across the southwestern Namibian coast between Oranjemund and Lüderitz will increase local electricity generating capacity from 400 to 600 MW[33]. As per the information from NamPower, two wind power projects currently have an effective licence issued by the ECB, and have firm planned commissioning dates:

- Lüderitz[34], 40 MW, with planned commissioning in 2024
- Diaz, 44 MW, with planned commissioning in 2022. Although Diaz wind farm is not included in NamPower's current business plan, the PPA was recently signed and the plant should be considered as committed. It is conservatively assumed that the plant will be commissioned in 2024.
- A 50 MW IPP is also included in NamPower's business plan to be commissioned before 2026.

[32] Namibia NIRP 2016
[33] Ewind, 'Ombepo Wind Farm went online in Namibia'
[34] This include an IPP sourced option.

Table 15 Lüderitz and Diaz wind Power Plant Technical Parameters

Parameter	Value	Parameter	Value
Coordinates	26°48'7.23" S; 15°10'12.99"E	Plant capacity	40 MW Maximum export capacity (MEC)
Location	9 km from the seashore, 20 km south of Lüderitz.	Planned Commissioning	2022
Plant lifetime	25 years	Energy per year	175.2 GWh
Wind Turbine generator Type:	Horizontal-axis wind turbine (HAWT) generator, up-wind turbines	Capacity Factor	± 50%
Power control:	Pitch & torque regulation, with variable speed;	Contractor's (EPC) Price – N$	N$ 1,053,003,000
Coordinates	26°48'7.23" S; 15°10'12.99"E	Contractor's (EPC) Price – kWnet	N$ 63,108,792
MOR	3 %	F&OM	N$ 276 / kW / year
FOR	3 %	Variable O&M	N$ 119 / MWh

Source: NamPower, Lüderitz Project Fact Sheet, 2018

5.2.5 Omburu Battery energy storage systems

BESS is one of a number of technologies that can be used to provide load following and other ancillary service capabilities and to store electricity for use at times when it is needed. A number of other technologies exist and could be used in place of BESS. BESS in this analysis can be considered as a generic regulated energy storage encompassing a range of technologies.

Storage applications will be a requirement for the system operator to provide proper balancing and demand following, keeping the grid stable and reliable.

Battery storage is likely to be the next disruptive technology for Namibia's electricity sector. Although still costly, prices have been falling over the past decade and the technology now has longer deep cycle discharge lifetimes and better efficiency. The technology provides for fast response load following, and its implementation is such that modular blocks can be added as required, with less development lead time. IFM applications will be a requirement for the system operator to provide proper balancing and demand following, keeping the grid stable and reliable.

BESS becomes increasingly interesting in Namibia in a context of (i) Increasing bulk national supplier time-of-use (TOU) tariffs, including fast-growing maximum demand and network access charges, (ii) significant discrepancies between bulk national supplier peak and off-peak energy charges, and (iii) increasing variable renewable energy from solar PV resources. A candidate BESS is under consideration for commissioning in 2022. The project design has been approved, a grid connection licence application was filed, and the Environmental Impact Assessment for Clearance has been submitted.

The BESS would be a lithium-ion phosphate battery bank of 58 MW of installed capacity and 75 MWh of storage volume. It would be connected to the grid-connected Omburu solar PV park which has a generation capacity of 4.5 MW, generating 13,500 MWh/year. The BESS is expected to be charged with excess grid-scale solar PV production and SAPP off-peak power. Its activation year is planned in 2022, and its economic lifetime is 19 years.

Table 16 Omburu BESS System technical parameters

Parameters	Value and units
Technology	Lithium-ion phosphate batteries
Fuel	Charged with RES SAPP off-peak power
Earliest commissioning year	2022
Nominal net power output	58 MW of discharging power
Storage capacity	75 MWh
Capex - contractor's (EPC) price	N$ 427,154,310
Capex - contractor's price/kWnet	N$ 7,468 / kWnet
Fixed O&M cost	N$ 788 / MWh
Variable O&M Cost (fuel excluded)	N$ 128 / kW / year
Storage costs	N$ 52 / MWh
Expected lifetime of the plant	19 years
Planned unavailability (maintenance)	5%
Unplanned unavailability (forced outage)	1%
Operating regime	storage

Source: (1) NamPower, Omburu BESS plant fact sheet.

5.2.6 Summary of committed plants

The following table gathers the key technical and financial parameters of committed plants.

Table 17 Committed power plants

Plant list	Plant type / fuel	Planned start date	Installed capacity *MW/MWh*	Min stable level	Heat rate *(GJ/MWh)* Capacity factor (%)	Costs		
						Capex N$	V&OM *N$/MWh*	Fixed costs N$/kW/yr
Anixas II	HFO/LFO	2022	53.25	20%	12.4 *GJ/MWh*	1,004 m	27	168
Otjikoto	Biomass	2024	40	30%	8.2 *GJ/MWh*	2,679 m	116	1,785
Khan IPP	Solar PV	2021[35]	20	N/A	~35%	400 m	108	/
50MW IPP	Wind	2023	50	N/A	~50%	1,434 m	108	/

[35] At the date of this Report, we were informed that the expected target COD is now end May 2023.

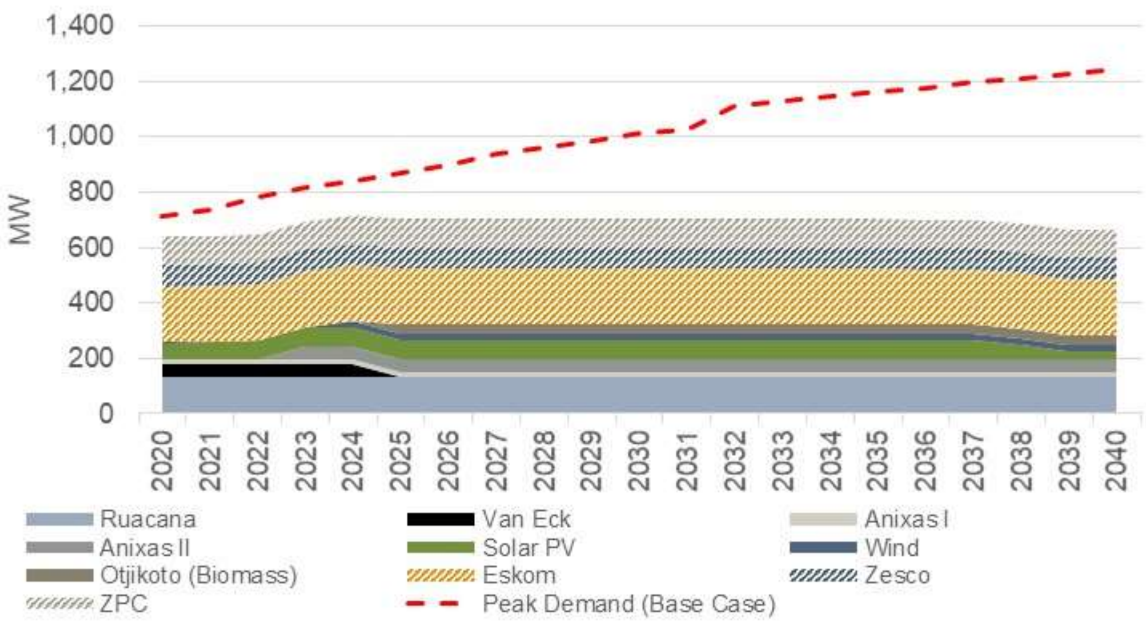
Plant list	Plant type / fuel	Planned start date	Installed capacity *MW/MWh*	Min stable level	Heat rate *(GJ/MWh)* Capacity factor *(%)*	Costs		
						Capex N$	V&OM *N$/MWh*	Fixed costs N$/kW/yr
Omburu I	Solar PV	2021[36]	20	N/A	36%	400 m	108	/
Lüderitz	Wind	2023	41.6	N/A	50%	1,262 m	108	276
Diaz	Wind	2022	44	N/A	50%	Not available	108	276
BESS[37]	Storage	2024	58	10%	n.a.	7,468	788.0	128.0

Source: NamPower.

5.2.7 Existing and committed capacity vs peak demand

Figure 11 compares the existing and committed plant capacity that is forecast and compares it to the peak demand forecast until 2040. Namibia is in a situation of structural sub-capacity and the gap will likely widen throughout the years. New additions (Anixas II and renewable power plants listed above) will not be sufficient to close this capacity gap and if no other plants are considered, Namibia will remain dependant on imports from neighbouring countries and the SAPP.

Figure 11 Derated existing and committed capacity vs. forecast peak demand



Source: ECA

36 At the date of this report, we were informed that the project's COD date is now estimated at 29 March 2023

37 Battery Energy Storage and Supply

5.3 Candidate power plants

This section of the report assesses and compares candidate projects and their technical (capacity, heat rates, capacity Factors for RES, etc) and economic characteristics (capex, opex, etc) options for Namibia.

5.3.1 Baynes hydropower plant

The potential large-scale hydropower projects identified for further study were the Epupa and Baynes schemes and were studied in detail at feasibility level in 1997. The study found both schemes to be financially viable with Epupa having some negative environmental impacts while the environmental impact of the Baynes option was much more acceptable but it relied heavily on the regulation of water to be released from the Gove Dam situated deep inside Angola. After carefully considering all options, the Namibian and Angolan governments decided to give the green light for the Baynes development to be studied.

Designed for peaking and mid-merit operations, Baynes hydropower could potentially provide about 600 MW of additional peaking generation capacity.

Table 18 Baynes Hydro technical parameters

Parameters	Value and units
Technology	Five Francis Vertical Axis turbines, two with a capacity of 71.0 MW and three 156.8 MW turbines.
Fuel	Hydro with storage
Earliest activation year	2030
Maximum operating level (MW)	600MW (of which 300MW is for Namibia, and the other 300MW is for Angola)
Capex	*N$* 22.3 billion
Grid costs	*N$*18.9 billion (not included in capex)
VO&M charge	*N$ 80 / MWh*
Annual Fixed cost	*N$ 560 / kW / year*
Operating regime	Mid-Merit

Source: NamPower

5.3.2 Lower Orange and Okavango hydropower plants

In addition to Baynes hydropower plant, two other hydropower options have been under consideration in Namibia: the Lower Orange River hydropower plant and a plant on the Okavango river. Both were excluded from the detailed analysis conducted in the 2016 NIRP. The proposed power plant on the Okavango river had been rejected by NamPower because of its small size and environmental issues, and it was not therefore included as a candidate. It is unlikely that the plant will be any more attractive for this NIRP update. The 100 MW plant on the Orange River is not considered further in this NIRP update.

The Lower Orange Hydro Electric Power Stations (LOHEPS) project consists of the development of up to 13 small run-of-river hydro electric power stations, varying in size and with an anticipated total installed capacity of some 108 MW. The first phase of the feasibility study was completed. However, the LOHEPS projects remain at a standstill as both parties cannot agree on a method to pursue a way forward. The likelihood of any further progress in the short to medium term is very unlikely especially if other projects under consideration are further developed. The NIRP assumes that the commissioning date will not take place before 2026.

Table 19 Lower Orange River Hydro technical parameters

Parameters	Value and units
Technology	Five Francis Vertical Axis turbines
Fuel	Hydro run-of-river
Earliest commissioning year	As of 2026, to be developed in 10 MW stages
Maximum operating level (MW)	108 MW
Minimum operating level (MW)	10 MW
Capex - contractor's (EPC) price	MN$ 5,625
Capex - contractor's price/kWnet	N$ 52,083 per kW net
Grid costs	MN$ 471 (included in capex).
Expected lifetime	50 years
VO&M charge	N$ 80 / MWh
Annual Fixed cost	N$ 600 / kW / year
Planned unavailability (maintenance)	4 %
Unplanned unavailability (forced outage)	4 %
Operating regime	Must run

Source: NamPower

5.3.3 Gas-fired power plants

The options considered in the NIRP include:

- The Kudu gas-fired power plant but modelled as an export plant with the price of power sold to the domestic market assumed to be at a slight discount to the import price. The technical characteristics and costs of the plant were not therefore relevant to the analysis;
- A Combined Cycle Gas Turbine and an Open Cycle Gas Turbine using imported LNG.

Several factors influence the selection of single unit size such as system operating reserve, system regulations, generation adequacy, the adequacy of plant load locations, load magnitude and its variability, fuel availability, and cost of transmission and distribution. For the present NIRP update, the net sizes selected for CCGTs are 350 MW (fuelled with LNG) and 475 MW (as per the information obtained from the Kudu Gas power project). The net sizes of open cycled gas turbine (OCGT) are 50 MW for the LNG fuelled plant (as per LNG based power plants across SSA which have included several 50 MW units) and 100 MW for the OCGT using Kudu Natural Gas.

Table 20 Candidate gas plants technical parameters

Parameters and units	Kudu	CCGT - LNG	OCGT - LNG
Technology	n/a	CCGT	OCGT
Fuel	Kudu NG	LNG	LNG
Earliest activation year	2026	2024	2024
Nominal gross power output	n/a	367 MW	43 MW
Nominal net power output	5 x 50 MW blocks	360 MW	42 MW
Net electrical efficiency	n/a	52.0%	31.8%
LHV net heat rate	n/a	6,926	11,310
Capex - contractor's (EPC) price [MN$]	n/a	5,363	646
Capex - contractor's price/kWnet [N$/ kW]	n/a	14,887	15,299
Fixed O&M cost *[N$ / kW / year]*	n/a	106.6	299.1
Variable O&M Cost (fuel excluded) *[N$ / MWh]*	n/a	60.3	80.4
Expected lifetime of the plant/contract	20 years	35 years	25 years
Emission level CO_2 *[kg/MWh]*	386	388	641.0
Planned unavailability (maintenance)	8.2%	8.2%	7.5%
Unplanned unavailability (forced outage)	4.4%	4.4%	2.3%
Operating regime	Mid-merit / base-load	Base-load	Mid-merit / Peak

Source: ECOWAS Power and Transmission Development Master Plan development, December 2018:
CCGT – LNG: GE 9E.03 - CCGT (300MW)
OCGT – LNG: GE 6B. 03 - OCGT (45 MW)

5.3.4 Fuel oil-fired power plants

Four main technologies are used to convert petroleum products (including both LFO and HFO into electricity):

- **Conventional steam** – HFO or Petcoke is burned to heat water to obtain steam to drive a turbine which in turn drives an electrical generator.

- **Combustion turbine** – LFO is burned under pressure to produce hot exhaust gases, which in turn spins a turbine to generate electricity.

- **Combined cycle technology** – LFO is first burned in a combustion turbine and then the exhaust gases of the turbine are fed in a heat recovery system which produces steam that is used to drive a steam turbine and subsequently an electrical generator. This technology recovers heat from the combustion turbine and drives a heat turbine.

- **ICRE** – LFO or HFO is combusted to push a piston within a cylinder. The piston connects to a crankshaft that transforms the linear motion of the piston into the rotary motion of the crankshaft. Most engines have multiple cylinders that power a single crankshaft. There are two primary reciprocating engine designs relevant to stationary power generation applications – the spark ignition Otto-cycle engine and the compression ignition Diesel-cycle engine. Diesel-cycle engines (with compression ignition) have historically been the most common type of reciprocating engine for both small and large power generation applications.

ICRE are a well-established and widely used technology and more efficient than combined cycle and conventional technologies. They are important for both transportation and for stationary uses. Their sizes range from small kW engines to large 80 MW power units. ICRE technology has improved dramatically over the past three decades, driven by economic and environmental pressures for power density improvements increased fuel efficiency, and reduced emissions.

Compression ignition diesel engines are among the most efficient simple-cycle power generation options on the market. Engines are further categorised by crankshaft speed in revolutions per minute (rpm), operating cycle (2- or 4-stroke), and whether turbocharging is used. The speed levels are high speed, medium speed, and low speed. Efficiency levels increase with engine size and range from about 30% (HHV) for small high speed diesels up to 42% - 48% (HHV) for the slow speed engines:

- High speed diesel engines (>=1,000 rpm) are available for up to about 4 MW in size;

- Low speed diesel engines (60 to 275 rpm) are available as large as 80 MW;

- Medium speed diesel engines (400 – 1000 rpm) are available for up to approximately 17 MW.

For the NIRP update we consider a power plant with similar technical parameters to the Anixas II power plant. As Anixas power plants already rely on an established HFO supply network, we consider that the new generic ICRE will also run with HFO.

The benefits of internal combustion engines are their relatively low investments costs, the speed of construction and the ease of storage and supply of fuels. Their big disadvantages are the higher costs of fuel per kWh, and their high specific consumption of fuel per kWh compared with some gas-fired alternatives. The candidate fuel oil option is a 20 MW medium speed HFO Wärtsilä 18V50 DF ICRE.

Table 21 Candidate ICRE plants technical parameters

Parameters	Value and units
Technology	ICRE
Fuel	HFO
Planned activation- decommissioning year	As of 2022 (can be fast-tracked)
Nominal gross power output	20 MW
Nominal net power output	96%
Net electrical efficiency	39.6%
LHV net heat rate	9,095 kJ/kWh
Capex - contractor's (EPC) price	MN$ 280.4
Capex - contractor's price/kWnet	N$ 17,517 / kW net
Fixed O&M cost	N$ 318.0 / kW / year
Variable O&M Cost (fuel excluded)	N$ 111.7 / MWh
Expected lifetime of the plant	20 years
Emission level C02	715 kg / MWh
Planned unavailability (maintenance)	7%
Unplanned unavailability (forced outage)	10%
Operating regime	Dispatched as per system requirements

Source: ECOWAS Power and Transmission Development Master Plan development, December 2018

5.3.5 Nuclear power plants

As per the definitions from the International Atomic Energy Agency (IAEA), the nuclear power generating units are divided into three size groups: small (under 300 MW), medium (between 300 MW and 700 MW) and large (over 700 MW). The two largest groups include the most operational units from the 20th century. The most common types of nuclear power plants include pressurised water reactor (PWR), boiling water reactor (BWR), gas cooled reactor (GCR) and advanced gas cooled reactor (AGR), light water-cooled graphite moderated reactor (LWGR), and pressurised heavy water moderated reactor (PHWR).

The World Nuclear Association reports 440 operational nuclear power reactors worldwide, which now provide about 10% of the world's electricity and represent the world's second largest source of low-carbon power (29% of the total in 2018). In SSA, South Africa is the only country currently producing electricity from nuclear. South Africa has two operational nuclear reactors, with a combined net capacity of 1.9 GWe, and, in 2019, nuclear generated 7% of the country's electricity. South Africa remains committed to plans for further capacity, but financing constraints are significant.

In 2007, the Government of Namibia, through MME, identified nuclear energy as an option to be considered for electricity generation, which has resulted in interest from foreign investors but never materialised. Small modular reactor (SMR) nuclear power plants were considered as an option in the 2016 NIRP, though screened out before the detailed analysis. The long expected lead time of such projects has to be considered. The lead time include all necessary components for the development of a nuclear power plant, listed below, including personnel training, establishment of a national nuclear regulatory commission and associated laws, regulations and codes, feasibility study, environmental and social impact assessment, construction, and commissioning. SMRs have however an expected shorter construction schedule than Large Reactors (LRs). The SMR expected schedule is 4/5 years for the First-of-a kind (FOAK) and 3/4 years for the nth of a kind (NOAK), instead of the 6/7 years (or even more) for LRs.

Due partly to the long lead times, the high capital cost of large nuclear reactors, and the reliability of large units for small electricity grids[38], there is a move to develop smaller nuclear power units. These units may be built independently or as modules in a larger complex, with capacity added incrementally. Small units are seen as a much more manageable investment than big ones whose cost are not readily absorbable by the utilities concerned.

The current SMR designs[39] are based on the usual materials used for cooling the reactor (eg water, gas, liquid metal, and molten salt), and the reactor may predominantly rely on a thermal or fast neutron spectrum in the nuclear fission process. Given the smaller and more simplified design of SMRs compared to a conventional LR, the amount of liquid, solid, and gaseous waste produced by the former is expected to be less than that generated by the latter.

SMR are already operating[40] around the world include:

- **China** – The first CNP-300 unit started operations in Qinshan Nuclear power plant in 1991. The reactor has a thermal capacity of 999 MW and a gross electrical capacity of 325 MW, with a net output of about 300 MWe. The CNP-300 was the first Chinese nuclear reactor to be exported, with the installation of the first unit at Chashma Nuclear power plant in Pakistan. The unit began operation in 2000 and another unit was completed in 2011 and other two reactors are under construction at the same plant. Other pilot projects are announced: a high temperature gas cooled SMR is built and in commissioning phase, with full commercial operation expected in 2021. Several versatile SMRs with combined heat and power uses are expected to be launched by the mid-2020.

- **The USA** – The US pressurised water SMR NuScale has recently become the first-ever SMR to receive design approval from the US safety authority; the boiling water SMR design by GE Hitachi is also in advanced stages of licensing.

- **India** – The Indian PHWRs programme consists of 12 units of 220 MWe.

[38] small electric systems cannot cope with large units in the case of an unplanned outage as it would make it largely unstable.
[39] International Atomic Energy Agency, Considerations for Environmental Impact Assessment for Small Modular Reactors, 2020.
[40] World Nuclear Association.

- **Russia** – The four 11 MW EGP-6 nuclear reactors located in the Bilibino nuclear power plant, Chukotka Autonomous Okrug, Russia, are the smallest and the northern most operating nuclear power units in the world. The first marine-based Russian SMR has been operational since May 2020; a construction project has been launched for a land-based SMR.

Two projects are currently in construction (a 27 MWe Integral PWR in Argentina and the most advanced SMR project is in China, where Chinergy is starting to build the 210 MWe HTR-PM, which consists of two high temperature gas cooled reactors (HTRs)). More are in near term deployment (15 projects ranging from 60 MWe to 300 MWe, in the USA, China, South Korea, Canada and Russia).

While operational costs of nuclear power generation (SMRs and LRs) are relatively low, its construction is capital intensive and requires the set up of numerous safety checks and environmental impact assessment. In addition, it requires a good national technological base and well trained human resources to operate and maintain such power plants. In light of this, it seems unlikely to anticipate the construction of a SMRs in the next two decades in Namibia. This is further confirmed by the factors listed below:

- **National nuclear regulatory authority**. There is currently no effective national nuclear regulatory authority in Namibia. Such authority formulates policies, develops regulations governing nuclear reactors and nuclear material safety, issues orders to licensees, and adjudicates legal matters. It is expected that from establishment of an effective national nuclear regulatory authority the licensing of reactors could take at least seven to ten years. The establishment of a nuclear regulatory commission can also take quite a few years as expertise has to be gathered to be part of such body.

- **Commissioning period.** In advanced economies, the selection of potential power plant site(s) and conduct of site environmental and social impact assessment could take from five to ten years. Pressure and lobbying groups are already in place in Namibia and are trying to sway popular opinion. The construction is likely to exceed five years after environmental and required approvals.

- **Financing access**. Access to finance is deemed to be difficult for such projects, especially for investors outside Namibia which would require full Government back up, support and participation especially with guarantees.

- **Base-load generation.** Under technical and economic constraints, a typical nuclear power generation unit can only be dispatched on a base-load operating regime. The appropriate time to build a nuclear power unit is when the system off-peak load could consume all the unit output. The lowest off-peak point was recorded at ~350 MW in 2019/2020, making the nuclear power plant candidate a small generator of ~300 MW. Nevertheless, at present, almost all small reactor technologies have not been licenced and approved by relevant authorities as they are for naval use and for research, for which economics are normally not an important factor in the decision making process.

- **Export demand.** Regional cooperation is required as the generation capacity of even a small nuclear power plant may exceed Namibia's ability to absorb the full generation capacity.

- **Transmission network**. The output from a nuclear power plant should be sent out to the grid through reliable transmission lines, without interruptions in order to minimise the risk of overheating. A nuclear power plant is normally connected to several transmission lines to obtain the desired redundancy. In order to avoid a bottleneck and other operational issues, these transmission lines would have to be connected to a strong point in the grid with several evacuating routes. Refurbishment and expansion of existing lines would be necessary before supplying nuclear power in the Namibian transmission network in order to mitigate any risk.

- **Maintenance and operation**. It requires considerable technical expertise and a technology base in order to be able to supply the specialist skills and products to a nuclear power station, to which Namibia has never been exposed and may need to import at considerable costs in the initial years of operation.

5.3.6 Wind

While the Diaz wind farm is expected to be commissioned in the short-term, it is not one of the projects that form part of NamPower's "Strategic Pillar, Ensuring Security of Supply" aiming at implementing 170 MW of new renewable generation projects. Diaz technical parameters are therefore based on Lüderitz wind farm project.

The Lüderitz wind farm project (40 MW of installed capacity) is used as a reference project for other candidate wind farms as the project costs are known through a feasibility study conducted in 2018 by NamPower[41]:

- For modelling purposes, the analysis considers generic wind farms with a 10 MW installed capacity across relevant scenarios;

- The Contractor's (EPC) price of the project is assumed to be N$ 26,325 per kW;

- Fixed O&M is estimated at N$ 276 per kW per year;

- Variable O&M costs are estimated at N$ 20 per MWh;

- The economic lifetime is assumed to be 25 years;

- The lead time would be from three to five years depending on permitting requirements, including resource quantification, scoping study, feasibility study, and EPC contract document preparation as well as tendering and awarding, financing closure, construction, and commissioning;

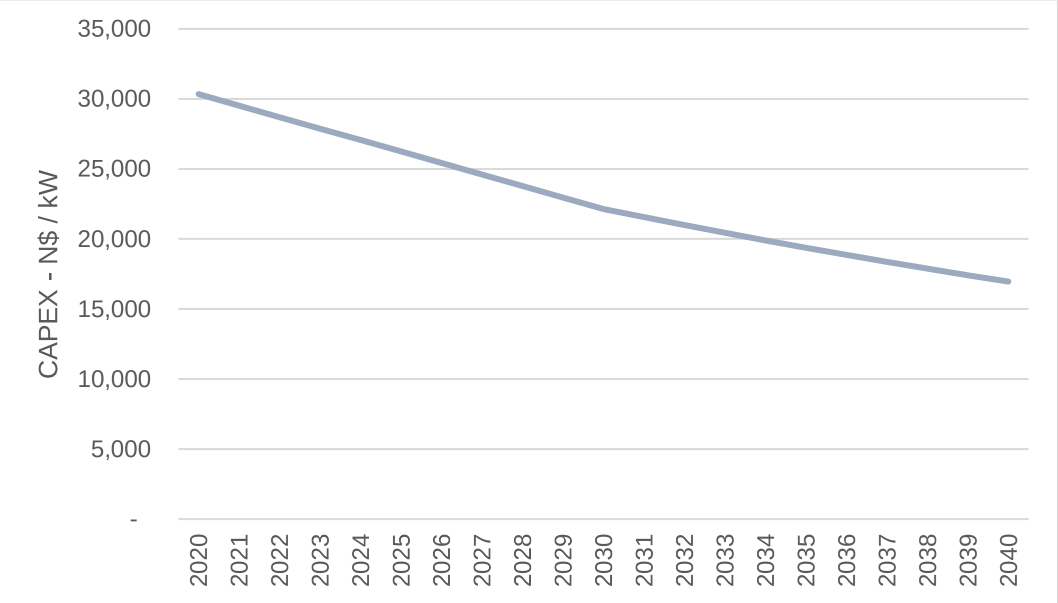
[41] NamPower, Project Fact Sheet: Lüderitz Wind Power Plant, 2018

- It is expected that the equivalent availability of the projects would be around 94%.

For projects commissioned in the longer term, we need to assume a decrease in today's estimate of capex for grid-scale wind projects, as a continuity of the trend already observed during the 2010-19 period. Continuous technological innovation remains a constant in the renewable power generation market, with onshore wind no exception. The global weighted average LCOE of projects using this technology and commissioned in 2019 was N$ 0.91/kWh — 9% lower than in 2018 and 39% lower than in 2010, when it was N$ 1.48/kWh. Onshore wind now consistently outcompetes even the cheapest fossil fuel-fired source of new electricity, while costs continue to edge lower.

International Renewable Energy Agency (IRENA)[42] predicts capex costs for new wind onshore projects will fall on average by 3.1% year on year until 2030. Beyond 2030, IRENA expects rate of decline of costs to reduce to 2.6%, year on year until 2040.

Figure 12 Wind onshore technology learning curve assumption



Source: IRENA, Power Generation Costs, 2019

5.3.7 Grid-connected solar PV

The Omburu solar PV project (20 MW Net) is used as a reference project for candidate solar PV farms as the project's costs are known through a feasibility study conducted in 2018 by NamPower[43]:

- For modelling purposes, the analysis considers generic grid-scale solar PV plant with 10 MW installed capacity across relevant scenarios;

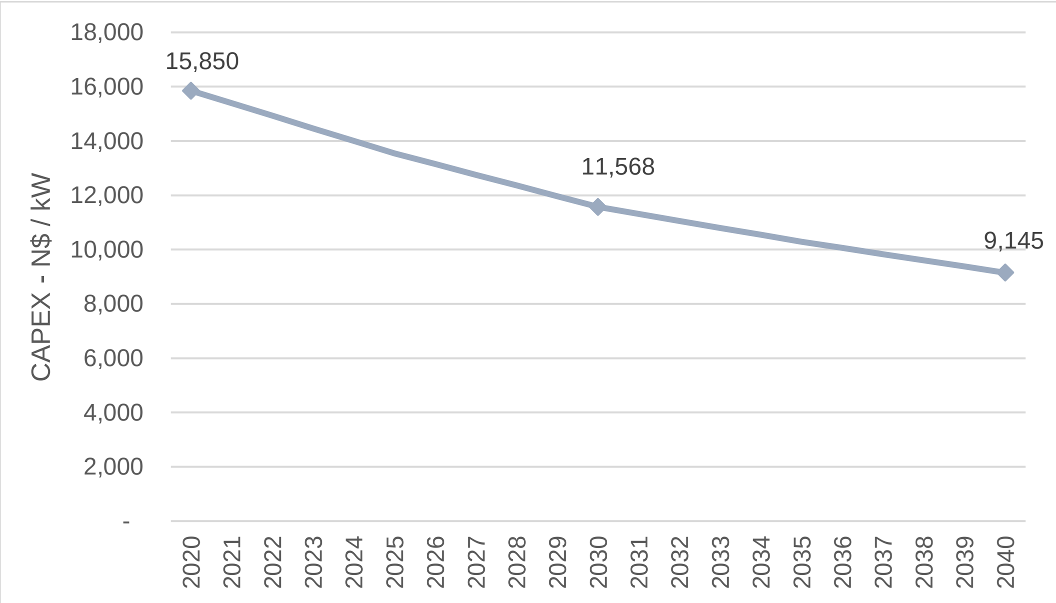
[42] IRENA, Power Generations Costs, 2019.
[43] NamPower, Project Fact Sheet: Omburu Solar PV Power Plant, 2018

- The Contractor's (EPC) price of the project is N$ 15,850 per kW;
- Fixed O&M are estimated at N$ 344 per kW per year;
- The facility economic lifetime is assumed to be 25 years;
- The lead time would be from less than one year to two years depending on permitting requirements, including resource quantification, scoping study, feasibility study, and EPC contract document preparation as well as tendering and awarding, financing closure, construction, and commissioning.

As for the candidate wind farm projects, a decline in capex is assumed in order to take into account future technology developments that will put downward pressure on overall costs. The continued decline in the cost of electricity from solar PV has been driven by reductions in the total installed costs for utility-scale projects with these declining by 79% between 2010 and 2019[44]. In 2019, the global weighted average total installed cost for utility-scale solar PV fell to just N$ 17,100 /kW, down from N$ 80,820/kW in 2010. This represents a year on year reduction in total installed costs in 2019 of 13%.

IRENA[45] predicts capex costs for new grid-scale solar PV projects will fall on average by 3.1% year on year until 2030. Beyond 2030, we expect the costs to fall by 2.3%, year on year, until 2040.

Figure 13 Grid-scale solar PV technology learning curve assumption



Source: IRENA, Power Generation Costs, 2019

44 IRENA, Power Generations Costs, 2019.
45 IRENA, Power Generations Costs, 2019.

5.3.8 Concentrated solar power plants with thermal storage

CSP stations are potential candidates for integration into the national grid together with other generation technologies. Central and southern Namibia is generally considered to be highly suitable for CSP power generation. There are currently no concrete solar thermal projects discussed, and no CSP plants.

CSP is a power generation technology that uses mirrors to concentrate the sun's rays (ie solar heat). Given the relatively high cost of power production with CSP, applications are currently limited to areas that provide the best solar radiation. The CSP market has been growing over the last several years: worldwide, there are 6,128 MW of CSP in operations, while another 3,139 MW are either in construction or in development. In Africa there is 1,340 MW of installed capacity (of which 500 MW in South Africa, 530 MW in Morocco and 310 MW in Egypt). However, compared with other renewable energy technologies, CSP can still be considered in its infancy, in terms of deployment.

There are different CSP technologies exhibiting different attributes (ie solar field, power block, and thermal energy storage) but they operate on the same principle: Solar heat is concentrated by mirrors and reflected onto a heat transfer medium (gas or liquid) contained in pipes. This medium then transfers the heat to water, producing steam, which drives a turbine. Electricity is then generated in a steam cycle, using the heat transfer fluid to create steam and generate as in conventional thermal power plants. CSP plants today typically also include low-cost thermal storage systems to decouple generation from the sun. Most commonly, a two-tank molten salt storage system is used, but designs vary.

The National Renewable Energy Laboratory (NREL) lists four main CSP technologies:

- **Parabolic Trough** – line-focus system composed of a set of concave mirrors that concentrate solar rays on the receiver tube that is located in the focus. These troughs can track the sun around one axis, typically oriented north–south to ensure the highest possible efficiency. The fluid flows through this tube and absorbs heat from the concentrated solar energy.

- **Linear Fresnel reflector** – line-focus systems that use relaxed and flat mirrors arranged to focus sunlight on a receiver.

- **Power Tower** – point-focus systems that use heliostats to focus sunlight on a tower-mounted receiver.

- **Dish/Engine** – point-focus systems that use curved mirrors to focus sunlight on a receiver.

Parabolic trough and power tower thermal stations are the most common applications of solar thermal technology across the world. CSP come in a wide range of installed capacities from less than 1 MW to more than 500 MW[46]. Storages usually include two tanks composed of

[46] DEWA CSP Trough Project is being constructed by ACWA Power in the United Arab Emirates. The project will be 600 MW with a 15-hours molten salt 2-tanks storage.

molten salts but variants exist with graphite or oil. Siemens is by far the biggest CSP steam turbines developer, followed by Alstom and GE.

With support from the Energy and Environmental Programme with Southern and East Africa (EEP S&EA), a Prefeasibility Study for the Establishment of a Pre-Commercial CSP Plant in Namibia was carried out in 2012. The concept design for the implementation of CSP in Namibia has then gone through different stages, from an initial small pilot project of 5 MW to a wider project scope with deployment of large utility-scale (50-150 MW) CSP plants. By June 2017, only the first phase of the full feasibility study was completed (funded by SE4All), including solar data assessment and measurements, multi-criteria and techno-economic assessment, and a concept of the CSP plant with technology (molten salt tower CSP) and site selection (Arandis) and with an environmental assessment. The end result of the Techno-economic analysis (Mott McDonald, 2016) comparing four options was that the 135 MW Parabolic Through CSP plant option with a 9-hour storage capacity on Arandis site received the highest Multiple-criteria decision making (MCDM) score combined with the lowest LCOE and capex. Phase 2 with project management and business planning, and financial engineering and the eventual EPC is still pending. Construction and operationalisation is expected to take from 1.5 years to 2 years, after financial closure.

The feasibility study led to the selection of the Arandis site with a 125-135 MW plant. The techno-economic analysis estimated the total project cost to be as high as US$ 770 million [47] (approx. N$ 10 billion in 2018), which presumably created additional difficulties in coming to a financial close.

Additionally, CSP projects can achieve the lowest LCOE by including storage to improve the overall utilisation of the project's power block and associated investments. According to IRENA, this has been reflected to some extent in trends in deployment, as the average storage of projects commissioned in 2018 (8.3 hours) was more than twice the level observed in 2010 (3.6 hours).

Table 22 Candidate CSP plant technical parameters

Parameters	Value and units
Technology	Parabolic Trough Solar Thermal Tower with Storage (3)
Storage	Molten Salt, 12-hours, 2-tanks (3)
Fuel	Solar irradiance
Earliest commissioning year	2025 (1)
Nominal gross power output	150 MW (3)
Nominal net power output	135 MW (3)
Capacity factor	53% (3)
Capex - contractor's price/kWnet	N$ 91,300 / kW (1)
Fixed O&M cost	N$ 183 / kW / year (1)
Variable O&M Cost (fuel excluded)	N$ 43 / MWh (1)

[47] UNDP/GEF/MME CSP-TT Namibia, Evaluation Report, 2018.

Parameters	Value and units
Expected lifetime of the plant	30 years
Emission level CO_2	-
Planned unavailability (maintenance)	8% (2)
Unplanned unavailability (forced outage)	7% (2)
Operating regime	Must run, storage

Source: (1) NamPower (2) Lazar, Levelised Cost of Energy Analysis, October 2020; (3) UNDP/GEF/MME CSP-TT Namibia, Evaluation Report, 2018

IRENA mentions CSP as one of the technologies with the largest cost reduction over the 2010-19 decade, alongside solar PV, and wind. The overall capital cost reduction for parabolic trough technology by 2020 was of 38% (compared to 2010 levels). Despite relatively thin deployment compared to other technologies, the CSP market is likely to continue experiencing a downward trend in the cost of electricity, as indicated by the evolution of PPA announcements for CSP projects, due to come online in 2020 and 2021. With its ability to provide dispatchable renewable power, CSP could therefore play an increasingly important role in facilitating ever-higher shares of variable solar PV and wind in areas with the direct solar resources to support CSP plants. A 30% decrease in overall capital costs between 2020 and 2030, and a steady reduction similar to that of solar PV (2.3%), year on year until 2040, as the technology reaches maturity is therefore likely to be witnessed.

5.3.9 Biomass power plants

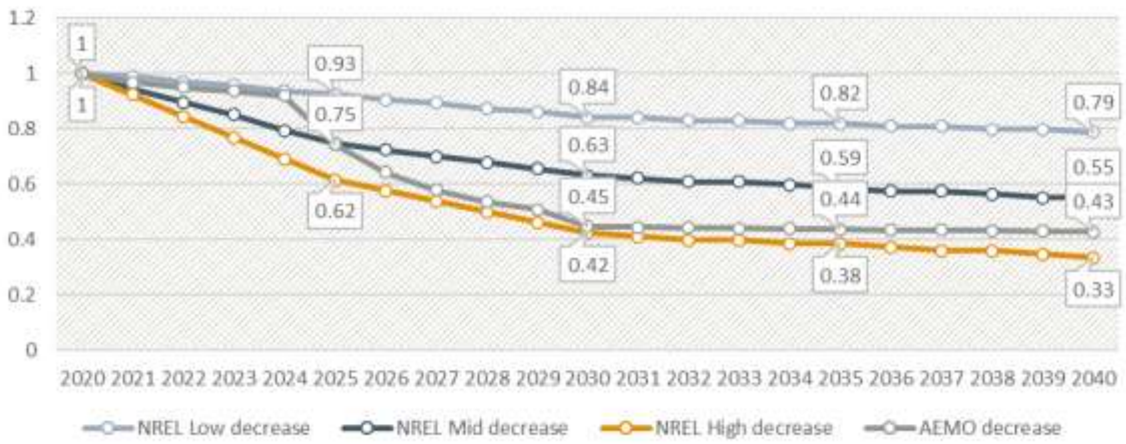
Candidate biomass power plant options are assumed to be designed under the same boiler and electric output technical parameters as the committed Otjikoto biomass power plant described in Section 5.2.

5.3.10 Battery energy storage systems

The generic battery storage system used in the least cost expansion approaches is based on the Omburu storage project, which is a regulated storage with short duration (1.5 hour of storage) and was therefore not designed specifically for arbitrage between time periods. However, adding multiple short duration BESS can alleviate longer spans of energy shifting. Going forward, the type and capacity of energy storage for the Namibian power system would need to be optimised through feasibility studies.

Over time, it is expected that battery storage costs will move downwards as underlying technology costs are reduced and market maturity brings further cost reduction opportunities through a combination of innovation, system integration, component and supply chain efficiencies, standardisation, reduced risk, operational efficiencies, and others. NREL and Australian Energy Market Operator (AEMO) provide cost reduction estimates for the lithium battery systems. The cost reduction estimates are shown in the figure below.

Figure 14 Lithium battery costs reduction over time relative to 2020 levels



Source: Cost Projections for Utility-Scale Battery Storage, NREL 2018; Capital Cost Projections, AEMO, 2019.

For the present NIRP update, we have adopted NREL mid-case projections regarding the reduction on the capital cost of lithium batteries.

5.4 Candidates import options

NamPower has concluded import contracts under fixed duration and fixed term conditions with South Africa, Zambia and Zimbabwe as discussed in Section 4.2.

Imports from other neighbouring countries are candidate in the NIRP update. Imports could come from anywhere in the SAPP region but particularly from the countries with the greatest potential energy resources (Angola, DRC, Mozambique, South Africa, Zambia). The DAM trades made up most of the energy traded in the competitive market (70%-75%), followed by intra-day market trades. The DAM market is currently split into 18 areas and featured the following most active participants[48] in 2018 (primarily buyers): Botswana (630 GWh), Namibia (774 GWh) and Central Zambia (215 GWh).

To the extent that the Southern African market will become increasingly integrated as transmission grids are strengthened, the price of power in any one of these countries should be no different from the price of power available from another, though transmission constraints do limit import possibilities from some countries, notably Angola. It is therefore more useful for the NIRP to consider the SAPP market as homogenous with a single price for the NIRP update. Since South Africa is the dominant player in that market, price trends are often determined by events in South Africa. The trends in the graphs below can be explained by the following:

- The South African economy has been slowing down since 2016. Its load has fallen and the need for imports has slowed, leading to a decline in SAPP prices.

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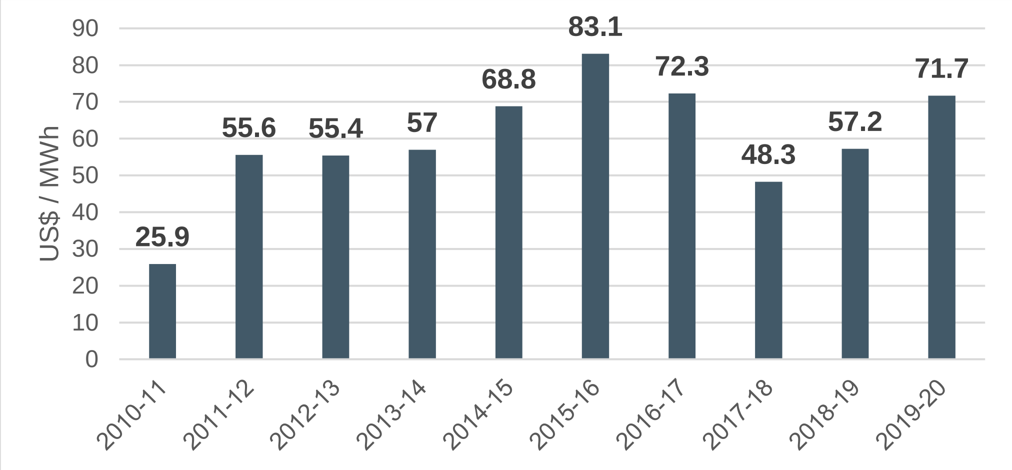
[48] http://www.sappmarket.com/

- Low rains affected production from the major Zambian and Zimbabwean hydropower power plants on the Zambezi River during 2015/16 which may have impacted SAPP demand in that period, pushing up prices.

- The rise in prices in 2019/20 may have been occasioned by supply problems in Eskom's power plants.

Figure 15 DAM annual average market clearing price ($/MWh)



Source: SAPP Spot Market

Future prices for electricity in the SAPP region have been modelled for the SAPP Pool Plan prepared for the SAPP Coordination Committee. The analysis entailed the calculation of the system marginal price (SMP) of electricity by country and across the SAPP region. It revealed, with some exceptions, a convergence of prices across the region within a relatively short period of time. A convergence in prices across countries results from the proposed reinforcement of the regional network and the removal of the current bottlenecks to trade across the region[49]. Even without the wider reinforcement of the SAPP grid, Namibia is strongly interconnected with South Africa and since South Africa dominates the market in terms of capacity and consumption, the marginal costs of electricity in Namibia will closely follow South African prices. The starting price for the SAPP imports candidate is based on a target monthly capacity charge of N$ 570 /kW/month[50] and an energy cost of USc 52 /kWh[51].

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[49] The main investments included major transmission lines from Inga to Angola, Zambia and South Africa and the backbone North-South transmission line (STE) running through Mozambique that would help relieve bottlenecks through Zimbabwe.
[50] US$ 33 /kW/month
[51] USc 3.0 /kWh

5.5 Summary of the long-list of candidate power plants and import options

Table 23 Candidate power plants

Power plant	Type	Fuel	Available capacity	Heat rate	FOR	MOR	Earliest commissioning	Economic lifetime	Capex	Variable O&M	Fixed O&M
			MWe	*KJ / kWh*	*% per year*				*N$ / kW*	*N$ / kW / yr*	*N$ / MWh*
L. Orange	R-o-R	Hydro	100	CF[52]	4.0	4.0	2026	50	5,625	80.0	600.0
Baynes	R-o-R	Hydro	300	CF	4.0	4.0	2026	50	5,625	80.0	600.0
Coal-fired	CFB	coal	150	9,730	10.5	10.8	2025	35	28,398	91.1	544.9
CCGT-NG	CCGT	Kudu NG	464	6,901	4.4	8.2	2024	35	13,735	99.5	56.4
CCGT-LNG	CCGT	LNG	360	6,926	4.4	8.2	2024	35	14,887	106.6	60.3
OCGT-NG	OCGT	Kudu NG	116	10,768	2.3	7.5	2024	25	10,417	279.5	75.3
OCGT-LNG	OCGT	LNG	42	11,310	2.3	7.5	2024	25	15,299	299.1	80.4
ICRE	ICRE	HFO	18	9,095	10.0	7.0	2022	20	17,517	318.0	111.7
Wind	Wind	Wind	10	CF	3.0	3.0	2022	25	26,325	276.0	119.0
Solar PV	Solar	Solar	10	CF	3.0	3.0	2022	25	20,000	434.0	0
Solar CSP	CSP	CSP	100	CF	7.0	8.0	2025	25	129,700	1,332	43.0
Biomass	Boiler	Bush	40	12,400	7.0	8.0	2024	25	66,975	1,785	116.0

[52] Capacity Factor

Power plant	Type	Fuel	Available capacity	Heat rate	FOR	MOR	Earliest commissioning	Economic lifetime	Capex	Variable O&M	Fixed O&M
			MWe	*KJ / kWh*	*% per year*				*N$ / kW*	*N$ / kW / yr*	*N$ / MWh*
BESS	Storage	Charge rate	50	n.a.	1.0	5.0	2024	19	7,468	788.0	128.0
SAPP Import	Import	Import tariff	80	n.a.	n.a.	n.a.	2021	10[53]	41,828	n.a	515.7

[53] 10 years represent a common interconnection contract term.

5.6 Screening analysis

At the screening stage a comparison is made of the unit cost of energy produced by each generation option including capital costs, operation and maintenance costs and fuel costs (if any). The screening stage gives an indication of the cost of producing one unit of energy (MWh) under specific conditions and therefore determining which candidate plants should be included in the more detailed generation planning analysis. We do not consider BESS in the screening analysis as this type of analysis is too simple to be used for such technologies.

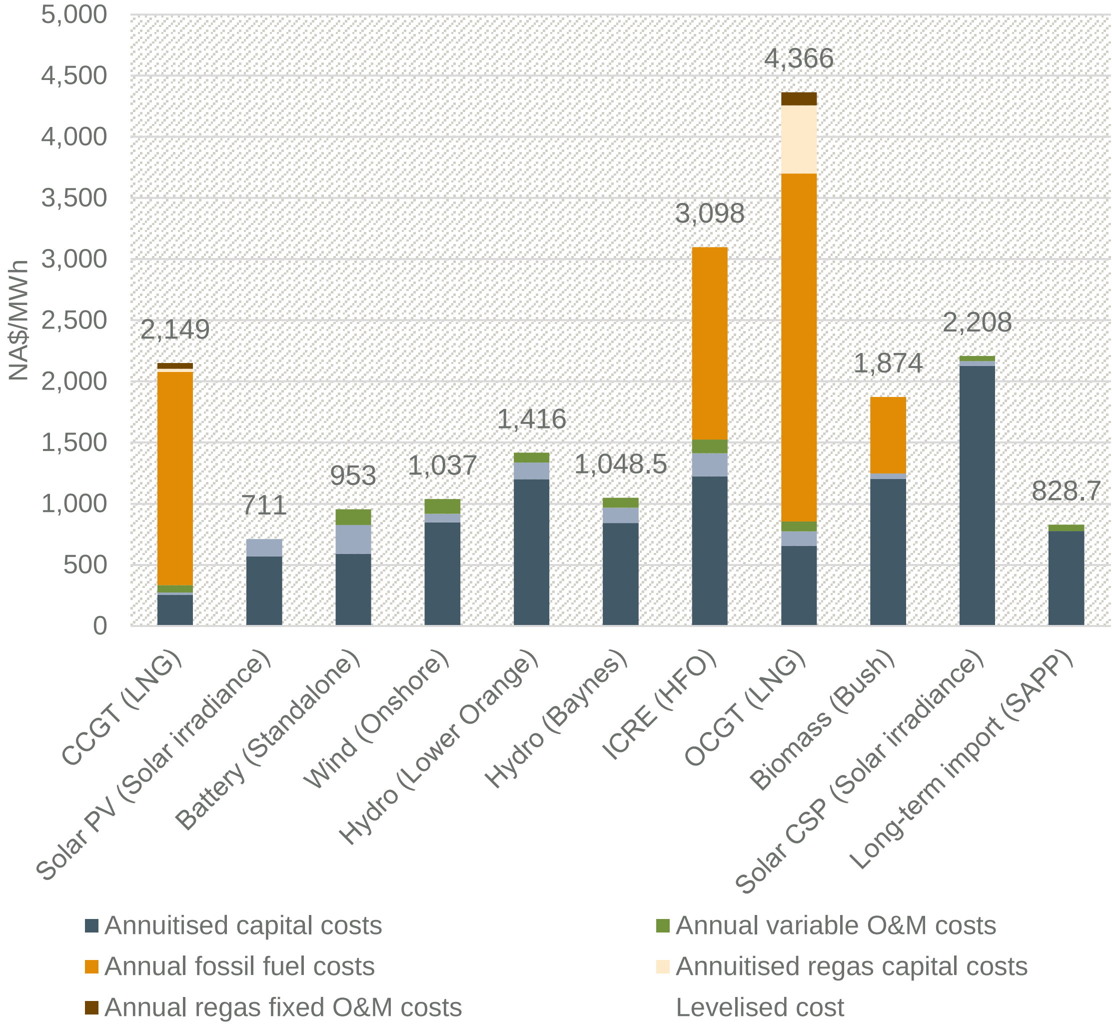
5.6.1 LCOE of candidate options

Based on the technical and economic parameters provided in Section 5.3 and the estimated cost of fuels, this section determines the levelised unit cost of energy (LCOE) for each of these candidate options.

When determining the LCOE the capacity factor should be specified. Since, at this stage, the number of hours at which the generation option will be dispatched is unknown, we assume a generic capacity factor based either on observed historic dispatch patterns (for existing plants) or on the basis of international benchmarks.

Figure 16 compares the LCOE of the candidate options. Although wide variations appear in the LCOE of the various candidates options (ranging from N$ 711 per MWh for solar PV to N$ 4,366 per MWh for CCGT fuelled with LNG), different types of units fill different roles in the electricity generation mix (e.g., base-load plants are capital intensive and the investment cost should be amortised on a large number of hours while peaking plants have high fuel costs and can quickly start-up for a limited number of hours). Units that operate at similar positions on the load curve (base-load, mid-merit or peaking) should therefore be compared against each other. Fuel costs used as assumptions are described in Section 6.8.

Figure 16 LCOE of candidate options (2020 prices)



5.6.2 Screening curves of candidate options

In this sub-section, a range of capacity factors are considered. We classify power plants in four categories in order to compare power plants with similar technical capabilities, costs, and roles in the energy generation:

- Thermal base-load power plants: Kudu Gas max 5x50 MW blocks, CCGT (LNG) 360 MW;
- Thermal peaking power plants: OCGT (LNG) 44 MW, ICRE (HFO) 20 MW;
- Intermittent renewable energy power plants: Solar PV 10 MW, Wind onshore 10 MW;
- Dispatchable renewable energy power plants: Biomass (Bush) 40 MW and Solar CSP 135 MW.

5.6.3 Conventional thermal base-load power plants

Figure 17 below shows the LCOE of a CCGT plant with imported LNG at different capacity factors. Base-load power plants are assumed to have an annual capacity factor in the 65% - 85% range.

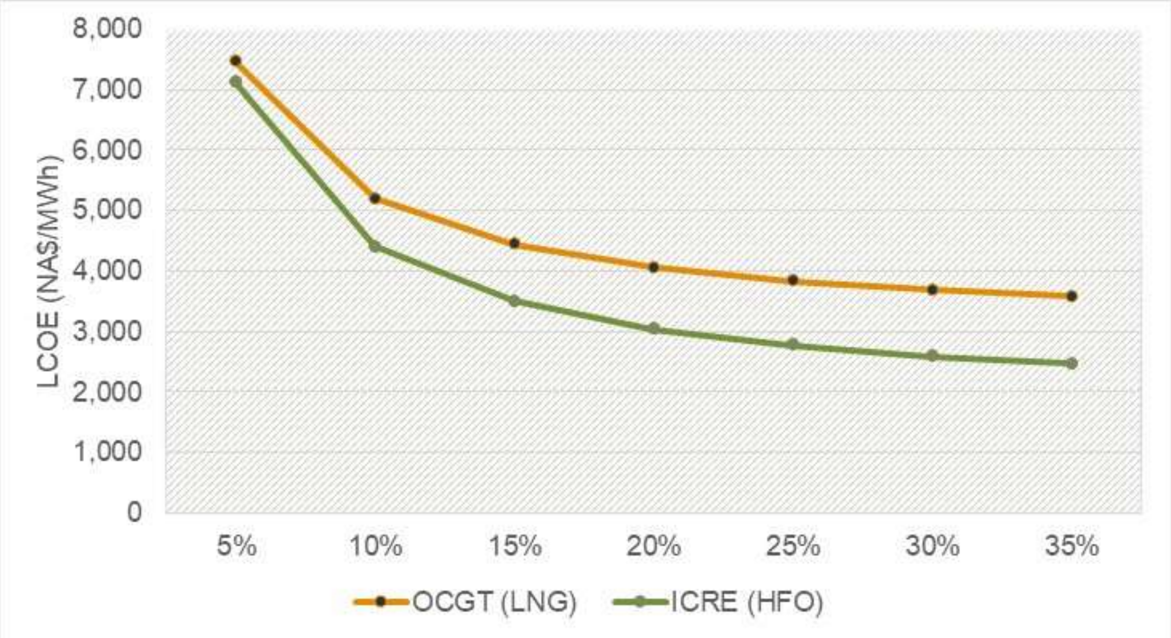
Figure 17 Screening curves of conventional thermal base-load power plants

Source: ECA

5.6.4 Conventional thermal peaking power plants

Figure 18 below compares the LCOE of peaking power plants at capacity factors in the 0% - 35% range. This shows that the ICRE plant has the lowest costs when used only occasionally as a backup when load is particularly high or when other plants have unexpected outages. However, at capacity factors above 25% the gas-fired technologies become more attractive. The screening analysis cannot distinguish in terms of LCOE between the two options based on natural gas.

Figure 18 Screening curves of conventional thermal peaking power plants

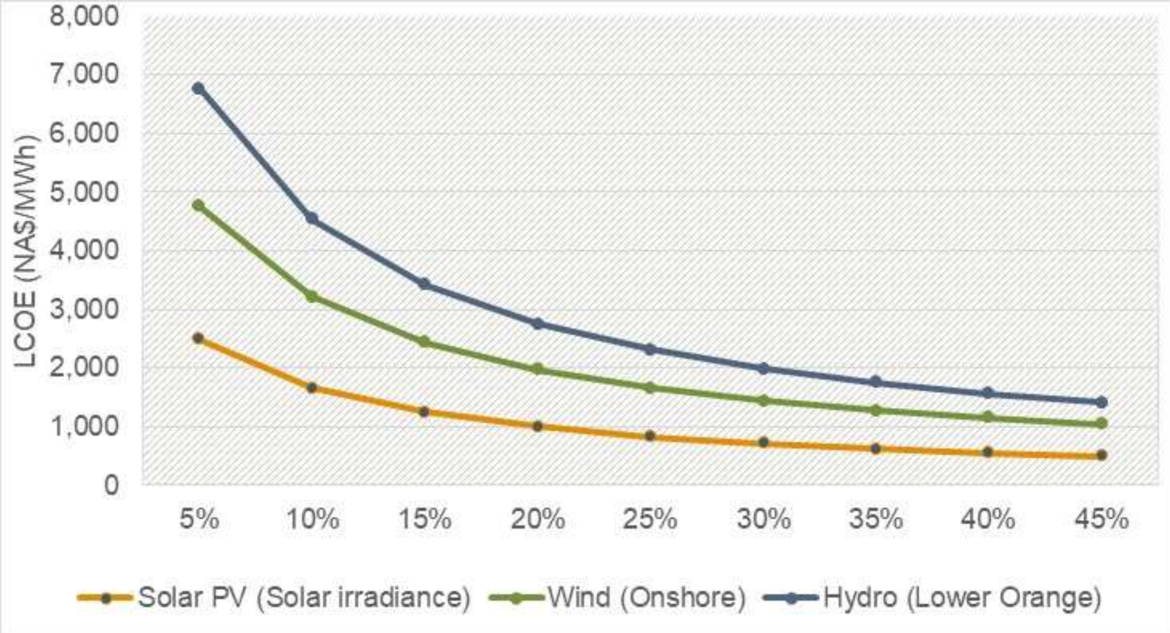


Source: ECA

5.6.5 Intermittent renewable energy power plants

The capacity factors of intermittent renewable energy plants are constrained by the hours of sunlight and the wind regime. Figure 19 shows the LCOE for various RES plants. The capacity factors of the intermittent plants are curtailed at their maximum expected annual production levels, with solar PV stopping at approximately 40% capacity factors and wind at approximately 50%. On the basis of this analysis, none of these options have been excluded from the more detailed analysis.

Figure 19 Screening curves of intermittent renewable energy power plants

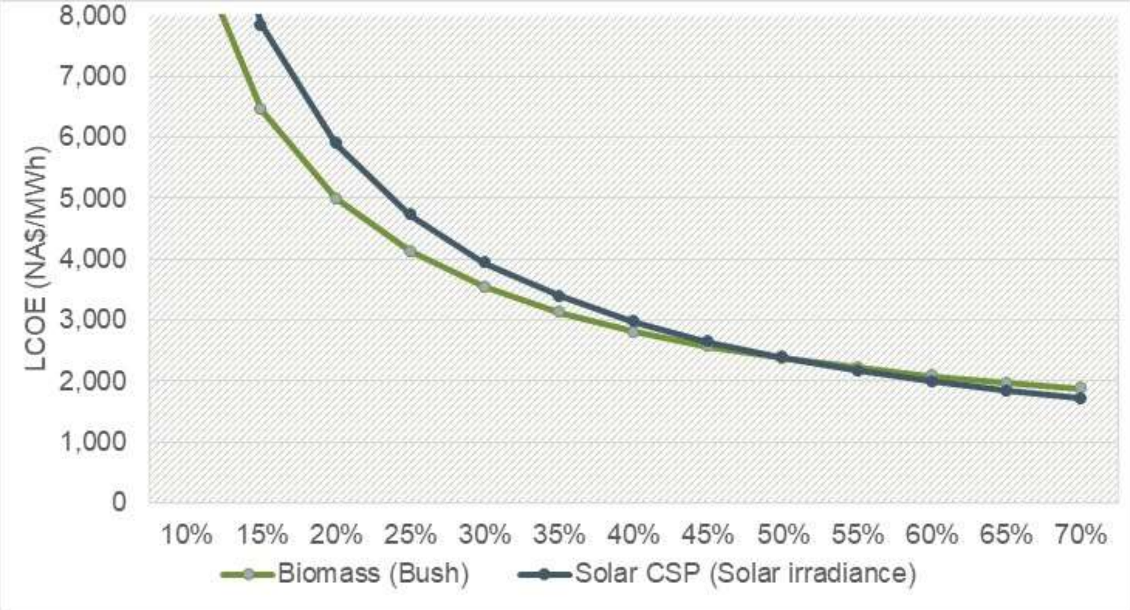


Source: ECA

5.6.6 Dispatchable renewable energy power plants

Dispatchable renewable energy plants are not constrained by the intermittency of solar irradiance or wind resources. Nevertheless, both biomass and solar thermal plants (CSP) present significant investment costs in comparison with conventional thermal power plants. From the screening analysis, the CSP competes with the biomass plant in the high fuel cost scenario in the analysis (N$ 600 per tonne), and levelised cost of energy. Both plants are therefore included in the least cost planning study.

Figure 20 Screening curves of dispatchable renewable energy power plants



Source: ECA

5.7 Summary of existing, committed and candidate options

Table 24 Existing, committed and Candidate power plants

Power plant	Status	Type	Fuel	Available capacity	Heat rate	FOR	MOR	Earliest (de-) commissioning	Economic lifetime	Capex	Fixed O&M	Variable O&M
				MWe	*KJ / kWh*	*% per year*				*N$ / kW*	*N$ / kW / yr*	*N$ / MWh*
Ruacana	Existing	R-o-R	Hydro	347	CF[54]	4.0	4.0	2050	n.a.	n.a.	1,020.0	16.0
Van Eck	Existing	Coal	Coal	81	15,810	13.0	13.5	**2024**	n.a.	n.a.	1,693.0	144.5
Anixas I	Existing	ICRE	HFO	20	8,500	10.0	10.0	**2047**	n.a.	n.a.	1,517.0	27.0
Solar PV plants	Existing	Solar	Solar	210	CF	3.0	3.0	**2037**	n.a.	n.a.	434.0	0
Ombepo	Existing	Wind	Wind	5	CF	2.0	2.0	**2046**	n.a.	n.a.	276.0	119.0
Eskom	Existing	Import	Tariff	200	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*
ZESCO	Existing	Import	Tariff	80	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*
ZPC	Existing	Import	Tariff	100	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*
Anixas II	Committed	ICRE	HFO	50	8,182	5.0	4.0	2024	25	18,860	525.0	168.0
Otjikoto	Committed	Boiler	Bush	40	12,400	7.0	8.0	2024	25	66,975	1,785	116.0
Omburu PV	Committed	Solar	Solar	20	CF	3.0	3.0	2022[55]	25	20,000	434.0	0
Khan PV	Committed	Solar	Solar	20	CF	3.0	3.0	2022[56]	25	20,000	434.0	0
Wind IPPs	Committed	Wind	Wind	90	CF	2.0	2.0	2024	30	26,325	276.0	119.0

[54] Capacity Factor
[55] At the date of this report, we were informed that the expected target COD is now end May 2023
[56] At the date of this report, we were informed that the project's COD date is now estimated at 29 March 2023

Power plant	Status	Type	Fuel	Available capacity	Heat rate	FOR	MOR	Earliest (de-) commissioning	Economic lifetime	Capex	Fixed O&M	Variable O&M
				MWe	KJ / kWh	% per year				N$ / kW	N$ / kW / yr	N$ / MWh
Omburu BESS	Committed	Storage	Charge cost	58	n.a.	1.0	5.0	2024	19	7,468	354.0	128.0
Baynes	Candidate	R-o-R	Hydro	300	CF	4.0	4.0	2030	50	36,509	80.0	560.0-
L. Orange	Candidate	R-o-R	Hydro	100	CF	4.0	4.0	2026	50	5,625	80.0	600.0
Kudu export	Candidate	n/a	Kudu NG	5x50 MW	n/a	4.4	8.2	2026	n/a	n/a	n/a	n/a
CCGT-LNG	Candidate	CCGT	LNG	360	6,926	4.4	8.2	2024	35	14,887	106.6	60.3
OCGT-LNG	Candidate	OCGT	LNG	42	11,310	2.3	7.5	2024	25	15,299	299.1	80.4
ICRE	Candidate	ICRE	HFO	18	9,095	10.0	7.0	2022	20	17,517	318.0	111.7
Wind	Candidate	Wind	Wind	10	CF	3.0	3.0	2025	30	26,325	276.0	119.0
Solar PV	Candidate	Solar	Solar	10	CF	3.0	3.0	2025	25	20,000	434.0	0
Solar CSP	Candidate	CSP	CSP	100	CF	7.0	8.0	2025	25	129,700	1,332	43.0
Biomass	Candidate	Boiler	Bush	40	12,400	7.0	8.0	2024	25	66,975	1,785	116.0
BESS	Candidate	Storage	Charge cost	50	n.a.	1.0	5.0	2023	19	7,468	788.0	128.0
SAPP Import	Candidate	Import	Tariff	80	n.a.	n.a.	n.a.	2021	10	41,828	n.a	515.7 .

Source: Consultant

6 Least cost planning criteria, policies, and parameters

This section provides the economic parameters, planning criteria and policies on which the NIRP update analysis will be based. In this section we discuss the Cost and Present Worth Datum, Discount rate, Currency and Exchange Rate, Cost of Expected Unsupplied Energy, the treatment of duties and taxes, and Interest During Construction.

6.1 Overall modelling approach

Dispatch modelling simulates the operation of the power sector at each time interval (typically by hour) for all possible combinations of power generations options given their technical, financial and economic characteristics. The results of each simulation can be used to identify the least cost plan. Dispatch modelling also allows planners to investigate multiple scenarios in terms of generation mixes as well as any other policies or sensitivities.

The results provide information on total capital expenditures; operating costs; fuel costs; emissions; revenues by unit; average, hourly, and regional prices; realised capacity factors over time; and reserve margins, among others.

Dispatch modelling is simulated using Wairoa. This is a long-term expansion and dispatch model developed by ECA power systems experts based on our extensive experience in modelling power systems around the world. It simulates electricity market outcomes under different conditions, using both enumerative and linear programming algorithms while capturing hourly dispatch constraints for typical days by season and long-term capacity expansion. Simulations can be run, even with large datasets, which allows testing of the sensitivity of results to multiple input scenarios. Wairoa is designed to be user friendly without requiring large input databases at extra charges.

Wairoa's objective function is to choose among the cheapest available facilities (while not exceeding their maximum capacity) in order to minimise the total system cost and meeting the total system demand. Mathematically, this model can be expressed as the following[57]:

$$Min_{G\ n,t} \sum_{t=1}^{T} \sum_{n=1}^{N} NPV_{\ t} \times G_{n,t}$$

Subject to:

$$\sum_{n=1}^{N} G_{n,t} = D_t$$

[57] This formulation is based on the Capacity Expansion and Dispatch Modelling White Paper, University of Texas at Austin.

$$0 \leq G_{n,t} \leq MG_{n,t}$$

Where:

- N, the total number of plants;
- T, the total number of hours in the generation window – 8,760 hours in one year;
- NPV_t, the Net Present Value of the total system cost (including capital costs, fixed and variable O&M costs, and fuel costs) in time t;
- $MG_{n,t,}$ the maximum generation available for power plant *n* during period *t*.

The second constraint limits the generation to the maximum capacity available for each power plant. For base-load power plants, the maximum available capacity is adjusted on a percentage basis by technology to approximate for maintenance schedules and outages probability. Wairoa does not include random events that might influence price like unexpected outages or extreme weather events. Wind, solar and hydro resources are dispatched according to hourly output profiles.

Wairoa treats the electric system as a single node (assuming there is no transmission constraints). The methodology to solve the dispatch problem is called the ‘merit order dispatch’. This problem is solved by ordering all available power plants by merit order (from the cheapest to the most expensive variable costs – O&M and fuel costs) and deploy them to match the demand and additional reserve requirements above peak demand for any given hour. Thermal plant efficiencies and their fuel prices are fixed within a year, but we assume a varying hourly price to reflect TOU import tariffs.

6.2 Economic and financial parameters

The NIRP update is prepared from a national perspective using economic costs or values rather than financial ones. Economic costs ignore, for example, taxes or royalties because these are transfers from one group within Namibia to another. The analysis does not distinguish between public or private ownership.

6.2.1 Cost and present worth datum

All costs are expressed in constant 2020 prices. All present worth and discounting calculations also use 2020 as their reference point.

6.2.2 Discount rate

The analysis is carried out using a social discount rate, that is, the rate of return on capital expected by society, rather than the investment criteria that may be used by the private sector.

Typical practice for national economic studies is to set the discount rate at 10 percent. This rate is used in this study to calculate the net present value (NPV) of input and output costs, expressed in real terms.

6.2.3 Currency and exchange rate

All monetary values are expressed in constant Namibian Dollars (N$), in border prices or equivalent. All economic costs and benefits exclude all local duties and taxes. The Namibian dollar is pegged at parity to the South African Rand thus a border price to South Africa would be equivalent to the Namibian border price with the addition of an appropriate transportation cost.

6.2.4 Duties and taxes, Interest During construction

Duties, taxes, and interest are not included in this economic study. Interest is a financial cost and as such is excluded from the economic evaluations. The construction period varies by technology and this affects the cost to develop the projects in present value terms. This is taken into account by distributing the capital expenditure over the entire construction period. We use the economic discount rate to inflate the costs to the commissioning date based on the economic discount rate.

6.3 Planning horizon

As per the requirement outlined in the TOR, the plan is to cover a development period of 20 years and it is intended to model the system from 2022 to 2042.

At the end of the simulation period, the various expansion scenarios can have different plant mixes with different remaining lives and different costs. A scenario that, for example, chose to develop a large hydropower plant in 2042 with high capital costs and low running costs, would be at a disadvantage compared with others that chose the investment earlier and that benefited from several years of low running costs.

In order to adjust for end-of-planning-horizon distortions, it is a common practice in integrated resource planning to account the full residual values of each investment. We use runout (defined in the Review Report) to avoid such distortions at the end of the planning period.

6.4 Reliability criteria

The primary objective of generation expansion planning is to find the least cost long-term expansion scenario that supplies the forecast demand at an acceptable or specified level of reliability. There are usually two types of reliability criteria used in generation expansion planning:

- A **deterministic criterion** – it is based on the ability of firm generation capacity to meet the demand in the event of the unforeseen loss of a generating unit. The deterministic reliability criteria are normally expressed in three different ways: (i) a fixed amount of capacity in MW to account for the random outage of one, two or more largest units, (ii) a percentage of annual peak demand, or (iii) a percentage of annual peak demand plus a fixed amount of capacity.

- A **probabilistic criterion** – it is based on a number of hours of unserved energy per year. It includes both the *loss of load probability* (LOLP), where a 1% LOLP indicates that the installed generation will not, on average, be able to meet the forecast demand in a given year for 87.6 hours; and the *expected unsupplied energy* (EUE), which is the quantity of expected energy that a system would not be able to serve with the planned generation system in a given year, expressed either in MWh or as a percentage. Both are obtained from the convolution of the load demand and available generation taking account of plant availability and reliability.

6.4.1 SAPP operating rules

SAPP defines its own reliability criterion, and, as a member of SAPP, Namibia is required to operate its power sector within parameters established by SAPP. The SAPP reliability criterion is a deterministic criterion in which "*the reserve capacity obligation of a member for any given period is to be equal to 10.6 % of the annual system peak of such member when the generating plant is thermal and 7.6 % when the generating plant is hydro. A weighted average is to apply to members who have a mixed system*". This can be satisfied using import contracts. It implies a minimum reserve margin of less than 10% for Namibia.

6.4.2 Criterion used in the 2022 NIRP

For the 2022 NIRP, reliability of supply will be ensured by targeting a reserve margin (deterministic criterion). All of the investment scenarios will satisfy this target reserve margin.

In this study, the target reserve margin is set at 10% of firm capacity above the peak demand relative to peak demand. The same reserve margin is used throughout the study horizon as agreed with the NIRP oversight committee.

6.4.3 Contribution of different technologies to firm capacity

The contribution of the intermittent RES (wind, solar and hydropower) to firm capacity is discussed in the following section.

Import contracts are assumed to provide firm capacity. Though it is possible to agree non-firm contracts, the analysis assumes that bilateral contracts would be firm. This is not a perfectly accurate representation of the import contract with Eskom but the reality is that the Eskom contract is very reliable.

The DAM market is assumed to provide non-firm energy and does not contribute to the reserve margin.

6.5 RES modelling approach

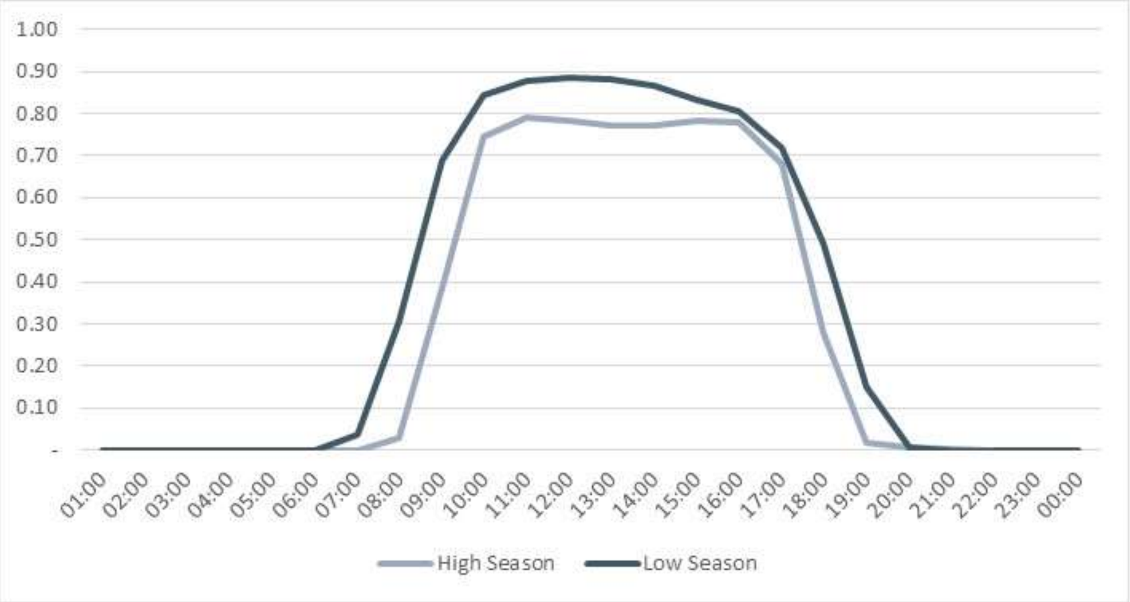
To model the operation of intermittent renewable energy generators (ie solar PV, wind and CSP), we have used hourly production profiles of existing projects. The hourly production profiles were sourced from hourly historical data from NamPower. For each candidate project, the hourly production profile was scaled to match the assumed annual capacity factor. Production profiles were developed for a typical weekday and a typical non-weekday for two seasons. The resulting curves are discussed in the sub-sections below.

6.5.1 Solar capacity factors

Existing solar plants (rooftop, embedded and grid-scale) as well CSP and subsequent additions are modelled on an hourly basis to reflect the intermittent nature of these technologies.

Solar capacity factors by hour are based on observed hourly output (MWh) from the existing plants in Namibia. Hourly outputs have been provided by NamPower.

Figure 21 Average Namibian solar PV power plants capacity factors by hour for a typical weekday and non-weekday, 2019



Source: NamPower

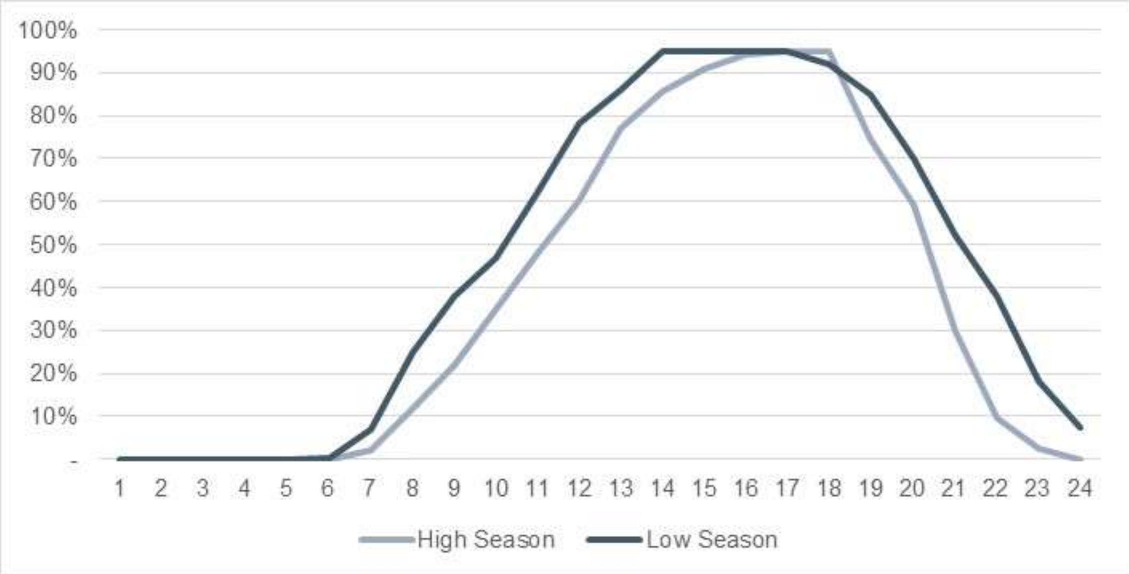
Solar capacity factors for CSP with storage are based on measured solar power output for the year of 2018 as provided on the Renewable Energy Data and Information Service platform[58]

[58] http://redis.energy.gov.za/

by the South African Ministry of Energy. Given that Namibia and South Africa have similar weather and irradiance conditions throughout a normal year, we use South Africa as a proxy. These load factors are based on the observed production (MWh) for CSP with storage. The hourly capacity factor values are scaled up to meet the expected output as described in MME feasibility study for the Arandis CSP site (which include a minimum 9 hours per day). The figure below shows the average weekly profile for the two seasons over the year 2018.

CSP was modelled with a fixed generation profile which allows it to generate partially during the evening peak when the solar output diminishes. This approach is a least cost dispatch optimisation of the CSP storage capacity but reproduces the expected outcome.

Figure 22 Average CSP with storage capacity factors, 2018



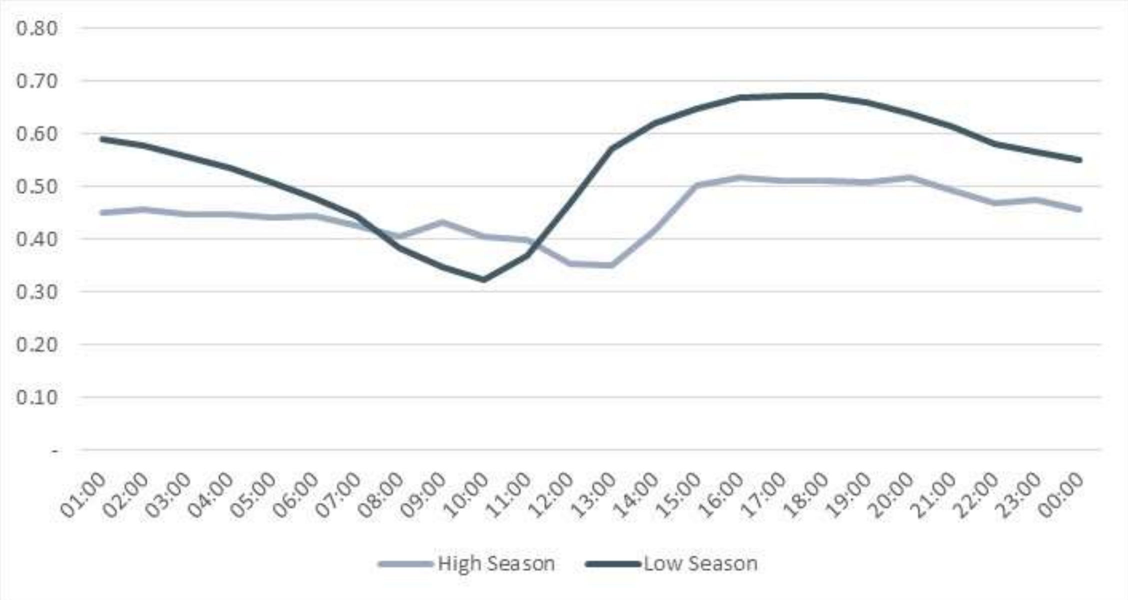
Source: South African Ministry of Energy – REDIS, scaled up to meet design output in "CSP Technology Transfer for Electricity Generation Study" (GEF-UNDP-MME, 2017)

6.5.2 Wind capacity factors

The figure below shows average weekday and weekend wind profiles for each of the seasons over the year 2019. The hourly profile is based on observed output from the Ombepo wind farm during the 07/2019 - 06/2020 period[59]. It has an average capacity factor of 50% which is above what is commonly observed for wind power plants. Such high wind availability in the Lüderitz area were confirmed by the feasibility study conducted by the project developer (Innosun/Innovent).

[59] The data was provided by NamPower.

Figure 23 Average wind onshore (Ombepo) load factor



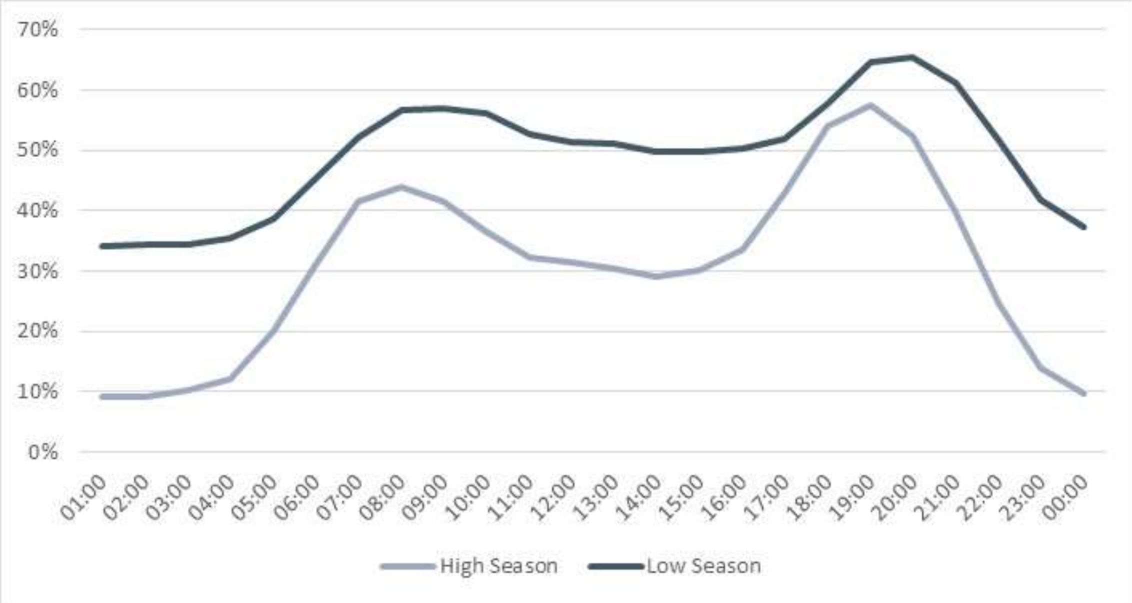
Source: NamPower

6.5.3 Hydro capacity factors

Two hydro projects will be simulated in our model: the existing run-of-river Ruacana plant (347 MW) and the run-of-river Baynes plant (300 MW).

NamPower provided hourly observed output power (MWh) for Ruacana from January 2011 to February 2020 (differentiated per unit). We have little information on the flows for the Baynes projects; however as it is situated 200 km downstream from the Ruacana dam, we assume the same capacity factors throughout the year apply to both plants.

Figure 24 Average hydro power plant capacity factors, average 2011-2020



Source: NamPower

6.5.4 Penetration of intermittent RES

The high penetration stated in RES policy targets will put a strain on the power system to maintain stability due to the intermittency of some of these technologies. High penetration therefore requires load and frequency regulation mechanisms. Several studies[60] have analysed the impact of the ability of the Namibia electric system to cope with the stated RES penetration target levels.

Mott MacDonald concluded that:

- Namibia is technically capable of installing 50% RES generation as a percentage of its midday load. This includes the midday minimum on weekends.
- Battery storage may provide a cost-effective method of reducing intermittency, compared to conventional spinning reserve.
- In an extreme statistical scenario (99th percentile) of pure reliance on intermittent power sources, 150 MW of spinning reserve would be required by 2030.

Given the above conclusions and that 58 MW of BESS charge capacity are already expected to be commissioned in 2024, it is assumed that an additional 100 MW of BESS will be required to cope with potential system stability in the mid to long-term. These additional 100 MW will be commissioned step-wise, with the first 58 MW in 2030, and the final 50 MW in 2035.

[60] (1) Intermittent Renewable Penetration Study - Mott Macdonald, (2017); (2) Study on grid integration of intermittent renewable energy in Namibia University of Stellenbosch, (2017-2018).

6.5.5 Contribution to firm capacity

The level of intermittency of supply options is determinant in determining the required level of firm capacity margin required to ensure a reliable supply of electricity. A ratio of firm capacity provision for each type of power plant is therefore included in the capacity margin provision calculation.

Table 25 Power plants firm capacity provision factors

Power plant	Contribution to firm capacity (% of total capacity)
BESS	100%
Solar PV	0%
Wind	20%
Ruacana / Baynes / Lower orange	100%
Imports Eskom / ZESCO / ZPC	95%
DAM imports	30%
Van Eck / Anixas I & II / Biomass	100%
CCGT (LNG) / OCGT (LNG) / ICRE (HFO)	100%

Source: ECA

6.6 BESS modelling approach

The key parameters relating to candidate battery storage investments include the following elements. They are based on the Omburu BESS project, as described in Section 5.2.

- Lifetime of the battery.
- Cost per MW of capacity.
- Variable cost per MWh of dispatch (if applicable).
- Efficiency losses on battery dispatch, which is derived from the roundtrip efficiency, equal to 9%.
- The storage duration is calculated as the hours of storage per MW of capacity (ie, the maximum amount of MWh the battery can store divided by its maximum instantaneous output. Eg, a battery capable of 1 MWh storage and 2 MW output would have 0.5 hours of storage per MW). The candidate storage duration value is 1.5 hours.
- Maximum hourly recharge as % of capacity (ie, the maximum rate at which the storage can be recharged in one hour. Can also be described as the ratio of instantaneous input capacity to output capacity. E.g., a 2 MW battery (output

capacity) with 1 MWh of storage capacity and 1 MW input capacity would have a max recharge of 50%. The model effectively assumes that maximum discharge is 100% of capacity).

When the model solves and determines the optimal generation investments, it does so by simulating dispatch each year. The simulation assumes that batteries are used optimally to store energy in some hours (for example during high solar output) and deploy it in other hours (for example during peak demand in the evening).

Therefore, the model will 'invest' in batteries only if they result in a lower overall system cost (ie, the avoided fuel costs of running thermal generators is greater than the cost of investing in batteries). This means that the model is effectively optimising the use of batteries for energy arbitrage (ie, storing energy across multiple hours; sometimes referred to as peak shaving). The model is not optimising the use of batteries in much shorter (sub-1-hr) time periods to maintain system stability, for example for frequency control and other ancillary services.

Also of note is the model's use of representative time periods.:

- Because the model is solving across a 21-year period and is Excel-based, it cannot practically simulate 8,760 hours x 21 years.
- Instead, it simulates four representative days per year (dry reason low, dry season high, wet season low, wet season high).
- By using representative days, the dispatch simulation does not capture the full variability of intermittent generation and instead assumes average output by hour from sources such as wind and solar.
- This is a reasonable approach, because it still gives a realistic depiction of the average utilisation of battery storage (e.g., in low solar output hours the batteries will be used less, in high solar output hours the batteries will be used more, but average battery utilisation will approximately match battery usage during average solar output hours).
- Nevertheless, the modelling approach is not 100% realistic and there will be some intricacies lost by the use of representative days, the importance of which will depend on the particular characteristics of the system.

6.7 Environmental and social criteria

Environmental and social factors can also be taken into consideration in choosing the optimal plan; this can be done either by placing an explicit value on certain emissions (as was done in the 2016 NIRP) or quasi-qualitatively by, for example, constraining the least cost plan in certain ways to set a target for the use of renewables or place a cap on the use of fossil-fuelled generation (this was also done in the 2016 NIRP).

The main environmental consideration for power plants is the expected levels of emissions from the combination of those plants (sulphur dioxide, nitrous oxides, carbon dioxide and other greenhouse gases, particulate matter, etc.).

For this study we use the CO_2 equivalent emissions – converting the amounts of other gases to the equivalent amount of CO_2 with the same amount global-warming potential (GWP)[61]. The reference CO_2 equivalent emissions for each generation option are included in Sections 4.1, 5.2 and 5.3. Namibia does not have national emission factors for the energy sector. Thus, the Intergovernmental Panel on Climate Change (IPCC) default emission factors were adopted to compute GHG emissions.

In the previous NIRP, an economic levy on thermal plants to account for the societal cost of emissions when comparing different forms of generation was applied. This was calculated as a value of N$ per tonne on the basis of the level of emissions – such as CO_{2e}, SO_2 and NOx – expected to be emitted by each plant type.

A carbon price of N$ 60/tonne was used in the 2016 NIRP. However, this is relatively high compared to international carbon market prices and, more importantly, this does not reflect the benefit to Namibia. A study on the country-level social costs (and equivalently the benefits of reducing emissions) of carbon[62] suggests values of between zero and US$ 1 per tonne of CO2e for Namibia. Since the value to Namibia of CO2e emission reductions is limited, we therefore propose to assume a zero value as the default assumption but the NIRP 2022 analyses the impact of scenarios that target emission reductions through RES investments or other measures.

6.8 Fuel price forecast

This section presents price assumptions for the fuels to be included in preparation of the NIRP update. The fuels considered include diesel (light fuel oil – LFO), residual (heavy fuel oil – HFO), natural gas (NG), liquefied natural gas (LNG), coal, uranium, and biomass.

6.8.1 Background

All liquid fuels used in Namibia are imported from world markets and are linked to some degree to the international market prices. The coal used in Namibia is also imported.

Forecast prices are based on the World Bank projections. This was selected given its broad perspective on commodity markets, detailed year-to-year price variations from 2020 until 2030, and because it incorporates recent COVID-19 impacts on demand and supply in their price forecasts. The World Bank acts as a knowledge hub, leading numerous agencies in major collaborative projects to monitor and report on energy development outcomes. In its Commodity Market Outlook of October 2020, the World Bank (WB) assessed the latest development in the crude oil, coal, and natural gas international markets.

[61] CO_2 is the reference and has a GWP of 1, CH4 presents a GWP of 25 and N2O of 298.
[62] Ricke, K., Drouet, L., Caldeira, K. et al. Country-level social cost of carbon. Nature Clim Change 8, 895–900 (2018)

The World Bank provides price forecasts for oil, coal, LNG, and natural gas until 2030. Our fuel cost projections beyond 2030 vary with growth rates projected during the 2025-2030 forecast period. The expected growth rates of crude oil, coal and gas are applied to current prices observed in Namibia, which include additional costs incurred to process and transport these fuels to the power plants. The only exception are biomass and uranium fuel costs, which we assume to remain constant:

Crude oil

The WB forecast predicts that the crude price would decrease from US$ 61.7/BBL in 2019 to US$ 41.4/BBL in 2020. Then crude oil would gradually increase from to US$ 52.6/BBL in 2025 and US$ 59/BBL in 2030. Beyond 2030, we assume that the HFO prices will grow at 2.33%, the same rate as during the 2025-2030 period. To account for transportation, handling, refining, insurance, and losses an additional cost of US$ 20/BBL is added.

Coal

Our coal forecast prices are based on the spot price for thermal coal (6000 kcal/kg) exported from Newcastle, Australia. The WB forecasts are FOB (free on board) prices and do not include the fees and costs for internal unloading, loading and transportation. The WB forecasts starts with a price of US$ 57.8 per tonne in 2020, which presents a sharp decrease from US$ 78.3 per tonne in 2019. Coal prices are expected to decrease steadily to US$ 50.6 per tonne in 2030.

Beyond 2030, Coal prices are assumed to grow at a negative rate (-1.47%), reflecting the transition away from coal for power supply. The cost of shipping, handling (including expansion facilities at a given port) and delivery to a power plant close to a major port is estimated at US$ 20 per tonne.

Natural gas from LNG.

We assume that Namibia will be importing LNG. The WB predicted a decrease in LNG prices in 2020, amid falls in global demand for natural gas following the recession. Although the impact has been much smaller than for oil, given the primary uses of natural gas are in electricity generation, industry, and residential/commercial heating, rather than in the transport sector. Based on recent cost estimates for a World Bank study in West Africa, assume the price of imported LNG is constant just below US$10/mmbtu through to 2030. Beyond 2030, as with HFO and coal, LNG prices are assumed to decline at the same rate as international LNG prices as WB projected during the 2025-2030 period.

Natural gas transported as LNG needs to go through the LNG chain from its production to the use for electricity generation in a power plant, ie production, liquefaction, transportation, regasification, and transport to the power plant location. The price of gas delivered at a power plant must therefore include all cost contributions from these five processes. The WB uses a cost-insurance-freight (CIF) import price which therefore covers only three of these components in the LNG chain: production, transport, and liquefaction. Infrastructure costs need to be factored in, in the total cost that CCGTs will be paying for LNG supply.

In the previous NIRP update, LNG imports via a Floating Storage and Regasification Units (FRSU) off the Namibian coast was considered as the most suitable option. Traditional Floating Storage Regasification Unit (FSRUs) consist of a jetty and a former LNG vessel reconfigured as a storage and regasification plant. The smallest FSRUs today provide storage capacity of 120,000 cubic meter. The following assumptions are taken to forecast the LNG price.

Table 26 Input parameters for delivery of LNG calculation

General parameters			
Discount rate	*%*	10.0%	*Assumption*
Lifetime FSRU	*years*	20	*Standard industry parameter*
Regasification in Namibia			
FSRU Capex	*$ million*	624	*ERIA*[63]
FSRB OPEX	*$/week*	460,000	*ERIA*

Regasification and transmission cost of US$ 3.81 / GJ: This is based on the LNG requirements of a 360 MW CCGT power plant, with 7.3 GJ per MWh (HHV) heat rate and annual capacity factor of 80%. This brings the annual gas consumption to 2.52 million MWh (or 174,600 tonnes of LNG, 18.4 million mmbtu).

Transmission cost through pipelines of US$ 0.61 / GJ were assumed: Assuming a 20km long pipeline from the FRSU unit to the CCGT, with a cost of US$ 2.5 million per kilometre and identical repayment and return on investment (RoI) parameters as for the FRSU unit.

Table 27 Detailed breakdown of cost of LNG

Breakdown	*N$/GJ*
West African cost estimate	*156.77*
LNG terminal capex	*68.81*
LNG terminal OPEX	*0.69*
Gas pipeline to plant	*10.49*
Delivered cost of LNG	**249.94**

Kudu Natural gas

The Kudu plant is modelled as an export project and, as such, the cost of natural gas is not relevant to the NIRP. Instead, Kudu is modelled as an export project that sells some of its output to the Namibian market at a discount to regional market prices.

[63] Economic Research Institute for ASEAN and East Asia, *Technical Report on the Modelling of a Small Liquefied Natural Gas Distribution Network in the Philippines*, June 2017

Biomass

Encroacher bush has potential in Namibia to fuel small biomass plants**.** Encroacher bush collection is both labour intensive and requires heavy machinery to cut the bush and transport it to a power plant. A recent project[64] to assess the financial viability of the Otjikoto biomass plant has assumed that the bush chip feedstock would cost about US$ 40.6 per tonne (N$ 698 per tonne) delivered to the plant.

The economic cost of biomass can vary from below zero, where there would otherwise be disposal costs or severe land or ecological degradation, to quite high, where there is an established alternative use in the region. As the NIRP is conducted in economic terms we are concerned here with the economic value of the fuel to the country rather than the financial cost of the fuel to the developer (NamPower). Since the farmers may themselves undertake bush clearance and aftercare in order to increase the productivity of grazing of the rangeland, the economic cost of this activity (bush clearance and aftercare) may be zero and the only additional economic cost is that of collecting the cleared bush and transporting it to the power plant. There may be additional processing costs if this is done during the harvesting or collection phase of the supply chain rather than at the power plant. There may also be other non-monetary ecological benefits in helping to eradicate encroacher bush that would lower the economic cost of the fuel. The economic cost of fuel is an important consideration for the economic viability of the plant and data is limited on the economic costs of the fuel compared with the estimated financial costs. Financial costs are important for the viability of a plant and the gap between the economic and financial viability may be covered from government or other sources. For the purposes of the NIRP, and because of uncertainty over the counterfactual bush clearance without the biomass power plant, for the screening analysis we consider a range of economic costs of biomass delivered to the power plant of:

- N$ 100/tonne,
- N$ 300/tonne,
- N$ 600/tonne.

6.8.2 Forecasts of fuel prices

Our assumed 2020 prices for the fuel types in the model are summarised in the table below. This table also converts all these prices to GJ as the common unit for modelling purposes.

Table 28 Assumed energy prices (2020)

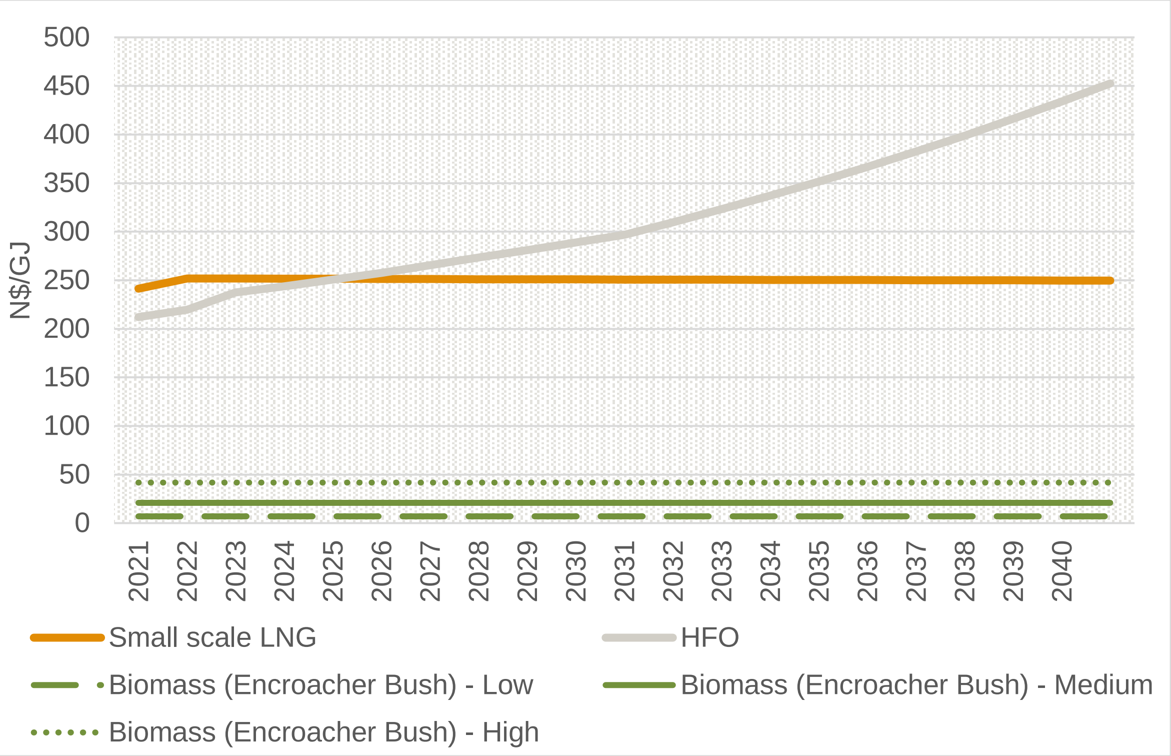
Fuel	**2020 energy price** *per pricing unit*	**Energy content** *per pricing unit*	*Transport and other costs N$/GJ*	**2020 price** *N$/GJ*
HFO	712 *N$/bbl*	6.10 *GJ/bbl*	57	173.1
Coal	994 *N$/Mt*	29.95 *GJ/Mt*	12	44.6

[64] GET FiT project in Namibia.

Fuel	**2020 energy price** *per pricing unit*	**Energy content** *per pricing unit*	*Transport and other costs N$/GJ*	**2020 price** *N$/GJ*
Imported Small scale LNG	175 *N$/mmbtu*	1.05 *GJ/mmbtu*	76	251.8
Bush	100 – 300 – 600 *N$ / Mt*	14.38 *MJ / kg*		7.0 - 20.9 - 41.7

The figure below shows the forecasts of prices for each of the fuels.

Figure 25 Fuel prices forecasts (2021-2040)



Source: ECA calculation

7 Generation least cost plan

7.1 Least cost planning scenarios

Least cost investment sequences were developed for seven policy scenarios as summarised below.

Table 29 Generation least cost planning scenarios

No	Scenario Name	Description
1	**Base case**	A least cost investment plan that is constrained by: • Compliance with the 2017 NREP to achieve a minimum 70% share of GWh supplied from RES (wind, solar PV, CSP, biomass and hydropower) gradually by 2030. • A self-sufficiency target of 80% of primary energy used in power generation – Namibian solar, wind, hydro or gas – within 7 years (i.e., by 2028). In this scenario, power from the Kudu gas-fired export power plant is assumed **not** to be available for the domestic market.
1a	**Base case (+ Kudu gas)**	As for the base case except that some power from the Kudu gas-fired export power plant is assumed to be available to supply the Namibian market at prices that are competitive with imports.
2	**Forced "base-load" power plant**	As for base case except that a 150 MW "base-load" plant is forced in to the investment plan. Other than Kudu, the only option that is available is a 150 MW CSP plant with storage. Other base-load options such as coal-fired or oil-fired power plants are not available because of Namibia's climate change commitments.
3	**No self-sufficiency target**	As for the base case except that the investment plan is not required to satisfy the 80% self-sufficiency target.
4	**Accelerated RES target**	As for scenario 3 above except that the achievement of the 70% RES target is brought forward from 2030 to 2026.
5	**Large power plant scenario**	In this scenario there are no RES or self-sufficiency targets (i.e., as for scenario (3)) except that that in this scenario it is assumed that the Kudu gas plant will be ready for dispatch in 2026 and 250 MW of the output will be available to Namibia at prices competitive with imports. It is further assumed the 300 MW Baynes hydropower plant would be commissioned in 2031. The timing of Kudu is based on its earliest commissioning date and the timing of Baynes is determined to satisfy the power system's reserve requirement (and system reliability).
6	**Unconstrained**	In this scenario there are no policy constraints.

Source: ECA

In the remaining sub-sections, the results from each of the selected least cost planning scenarios is described in more detail. But first, in Section 7.2, some of the project risks associated with the projects under consideration are summarised.

7.2 Summary of project risks

Certain project risks for some of the larger projects are summarised below and should be recognised when assessing the investment options under consideration.

7.2.1 CSP project

Key risks include:

- Whether GRN will be able to provide sovereign guarantees for offtake default, expropriation, riots and strikes and inconvertibility of currency.
- There are only a few reputable EPC contractors (especially for tower technology) in the market and that there may be limited interest in bidding.
- That there may still be some residual technology risk for tower technology.

7.2.2 Baynes project

The risks associated with the joint hydropower project with Angola are:

- Future water flows may reduce due to climate change and /or uncontrolled water offtake off from the irrigation schemes upstream from the Baynes project. There is also a risk of uncontrolled release of water from Gove and Calueque dams. However, as the Angolan counterparts have a stake in the Baynes project these uncontrolled releases of water may not be an issue.
- There is a risk that the relationship may break down with the Angolan counterparts and this would affect shareholding and operations / maintenance of the power station.
- The project can be considered as a serious alternative to the CSP project as a dispatchable plant to provide firm power. However, delays in implementation of the project could be expected given that the project is intergovernmental in nature.

7.2.3 Kudu gas-fired power plant

Several key challenges identified are:

- The project would necessarily be procured on an unsolicited basis and may be challenged by third parties.
- GRN may not be able to provide sovereign guarantees for offtake default, (termination costs are typically debt plus profit plus breakage if GRN/NamPower defaults), expropriation, riots and strikes and inconvertibility of currency.

- There may be tariff price volatility or tariff increases due to the tariff being denominated in US dollars and N$.
- Taking a long-term view on the supply and demand of the country and matching a 20 year PPA with the seasonality of the Ruacana Power station and future uptake of solar PV and wind power plants in the country, may mean that energy in the daytime be spilled or sold on SAPP.

7.2.4 Gas-fired technology using imported LNG

The primary concern with scenarios involving CCGT and OCGT technologies using imported LNG is that it would put the country under duress from significant forex and commodity risk exposure associated with a plant based on imported LNG. This is linked with the policy to encourage indigenous energy sources.

Other risks can be summarised as follows:

- Significant sovereign guarantees will be required to underwrite an LNG project to cover government risks and offtaker default.
- Large volumes of LNG (and electricity offtake) would be required to cover the fixed costs of the FSRU; which typically drives up the cost per unit of electricity for the size of plant required for Namibia. To achieve the policy of 80% self-sufficiency a CCGT plant using LNG could not operate as a base-load plant and this would normally make it unattractive for the developers or costly for Namibia.
- Due to the significant costs to hire these vessels, the offtake from these projects are usually fixed at based load with little room to negotiate any changes on seasonality for instance.
- The OCGT project using imported LNG was an option that was tendered and assessed under the Xaris project and found to be not feasible due to the issues listed above.

7.3 Base case scenario

The base case scenario identifies the least cost generation plan that would satisfy the base demand forecast under the constraints of:

- Compliance with the 2017 NREP to achieve a minimum 70% share of GWh supplied from RES (wind, solar PV, CSP, biomass and hydropower) gradually by 2030.
- A self-sufficiency target of 80% of primary energy used in power generation should be Namibian (solar, wind, hydro or gas) within 7 years (i.e., by 2028).

In this scenario, power from the Kudu gas-fired export power plant is assumed **not** to be available (e.g., if the expected prices are unacceptably high for NamPower to accept and the output from Kudu would all be allocated for exports, or the development of the gas resources cannot be assured)

A summary of the main results is provided in the table below.

Table 30 Summary of results – base case

Item	Unit	2021	2025	2030	2035	2040
Capacity						
Peak demand	MW	737	870	1,011	1,161	1,243
Energy						
Energy demand	GWh	4,514	5,242	6,041	6,835	7,439
Storage energy	GWh	-	143	207	283	301
Energy Generation	GWh	4,514	5,386	6,248	7,118	7,741
Share of indigenous energy	% of total	40%	89%	91%	93%	94%
Share of imports	% of total	60%	8%	7%	8%	6%
Share of RES	% of total	33%	86%	87%	88%	90%
Costs						
NPV of total costs	mN$	56,189				
GHG emissions	thousands t CO_{2e}	1,436				

Source: ECA analysis

Generation capacity

The total new least cost domestic generation capacity selected in the base case plan over the period 2021-2040 is 3,116 MW (266 MW committed and 2,850 MW candidate). The import contracts are not renewed in this scenario and no new candidate import option is selected.

The model chooses grid-scale solar PV and wind as the least cost options to satisfy the demand and to meet the policy objective of reaching 70% of RES generation and self-sufficiency. Solar PV and wind satisfy demand during the daytime, and the night peak hours are supplied by a combination of Ruacana hydro, biomass, Anixas I and II, and BESS.

The plants with firm capacity together with BESS and the DAM ensure that demand is met when the intermittent RES plants are not producing power. Batteries are forced in as a non-least cost option partly to reduce system operating costs and partly to cope with the risk that such a high intermittent RES penetration threshold poses in terms of frequency variations and supply intermittency. However, the model finds that it is optimal to invest in batteries above the minimal required capacity in order to store large RES generation and avoid curtailing cheap generation sources.

The table below shows the technologies selected as least cost by the optimisation model together with the committed plants and the amount of capacity commissioned for each technology in each year.

Table 31 Selected new capacity added each year – base case scenario (MW)

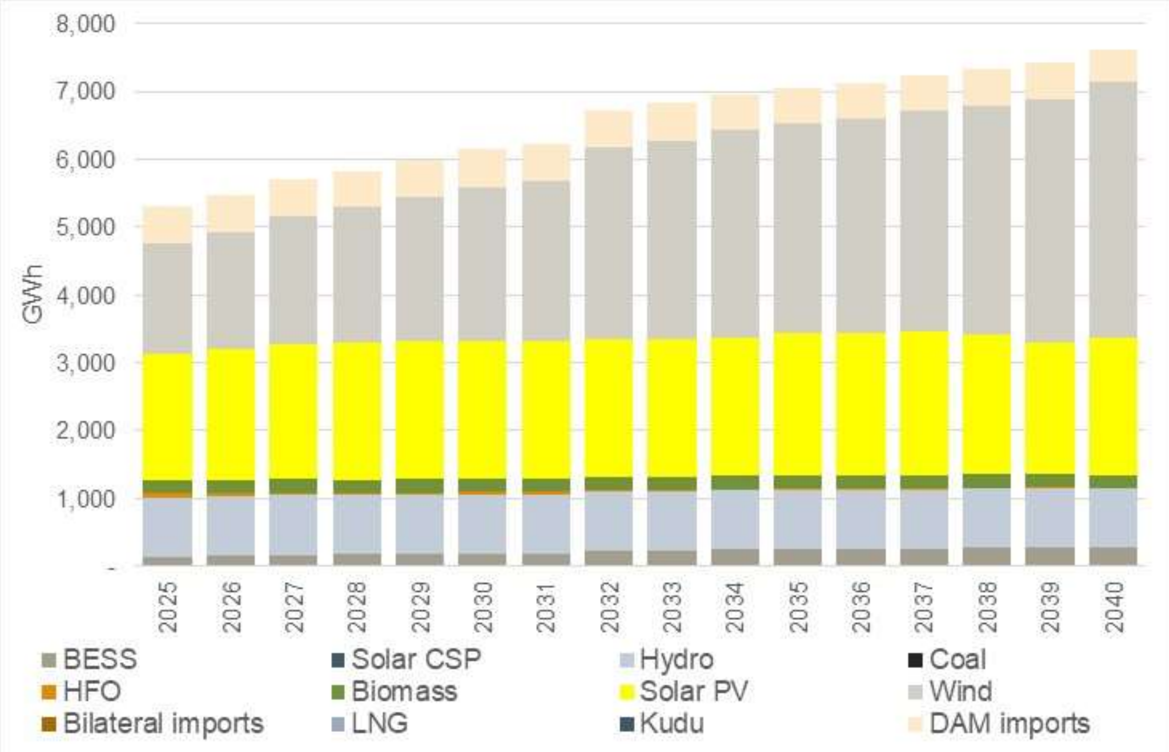
Fuel	BESS	HFO	Kudu	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Natural gas*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
2022 - 2030	500	50	-	40	936	730
2031 - 2035	150	-	-	-	330	30
2036 - 2040	-	-	-	-	280	70
Total	650	50	-	40	1,546	830

Source: ECA Analysis

Generation (GWh) by year

Figure 26 shows the generation mix by year. In 2021, the generation mix is dominated by Ruacana and imports. Van Eck also marginally contributes to the supply until de-commissioning in 2025. The growing demand is met by the large investment in solar PV and wind. Although the investment plan is required to satisfy the policy constraints of 70% RES and 80% indigenous energy, as described in the unconstrainted scenario below, the model would have chosen this investment path even without these policy constraints.

Figure 26 Generation mix by year – base case



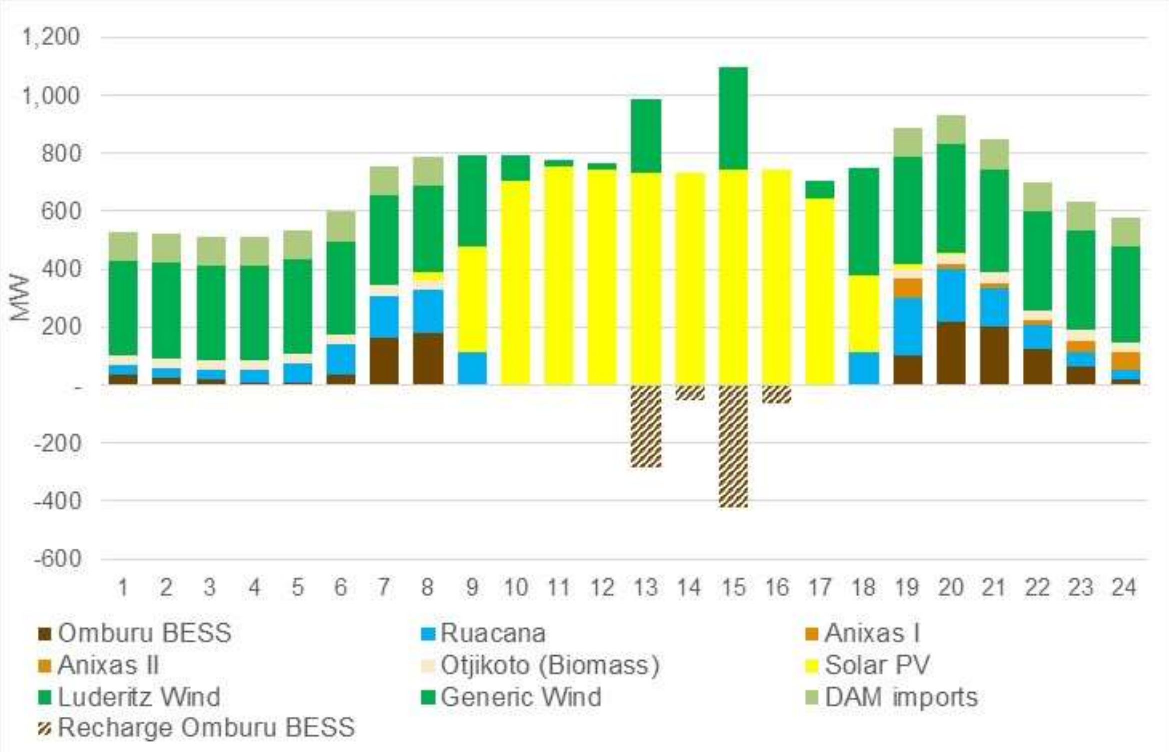
Source: ECA analysis

Cumulative GHG emissions reach 12,609 thousand tonnes of CO_{2e} in 2040. CO_2 emissions decreased considerably after 2025 as RES generation increases to meet targets. Emissions are mostly driven by Van Eck and Anixas I until 2025 when Van Eck is expected to be decommissioned. Anixas I and II are the only emitting source beyond this date but are predicted to have very low capacity utilisation.

Typical hourly dispatch

Figure 27 illustrates a possible operation of the power plants during a typical day in the dry season in the base case. During the daytime, the solar PV plants would supply most of the power to the grid. Diversity of location of the solar parks around the grid would help avoid large swings in production from the solar PV parks at short notice that could otherwise create grid instability. The diagram shows that wind production would be curtailed during the daytime except when it is used to charge the BESS for later generation during the evening and at night. Diversity of location of wind resources would potentially allow wind energy to be produced throughout the day and night.

Figure 27 Dispatch on a typical day (2030) – dry season: Base case



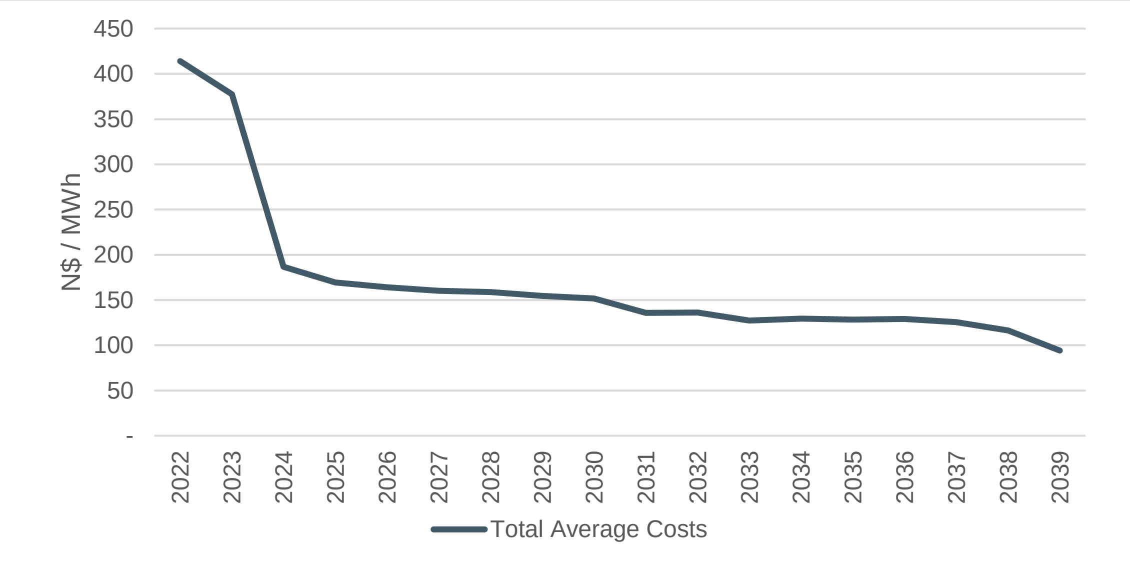
Source: ECA

Pathway of average costs

Figure 28 presents the annual average costs. These costs include the variable fuel, import, and O&M costs of running the power plants and do not include historical or projected capital investment costs.

Although not explicitly required for the NIRP conclusions, some stakeholders have shown interest in understanding the electricity cost forecasts of the study. The fall in the average costs from their 2022 levels is explained by the commissioning of large capacities of solar and wind farms, decreasing reliance on import contracts and the commissioning of Anixas II and the biomass plant (fuel and running costs only). As the analysis does not consider whether the plants will be developed as IPPs or internally by NamPower, these costs do not consider the cost of electricity purchased through contracts with solar and wind IPP developers and include only their O&M costs.

Figure 28 Average cost forecast



Source: ECA

7.4 Base case scenario with Kudu

The input assumptions to this scenario are identical to the base case described above except that some of the capacity and energy from the Kudu gas-fired export power plant is assumed to be available to supply the Namibian market at a price that is 10% below the assumed PPA prices for firm bilateral import contracts. The model is offered blocks of capacity from Kudu of 50 MW each and the model can choose as many of these blocks as it needs, up to a maximum of 250 MW.

A summary of the main results is provided in the table below. In this scenario, the plant is found to be part of the least cost solution and is chosen as soon as it is assumed to be possible to finance, develop and commission it (assumed to be in 2026).

Table 32 Summary of results – base case with Kudu

Item	Unit	2021	2025	2030	2035	2040
Capacity						
Peak demand	MW	737	870	1,011	1,161	1,243
Energy						
Energy demand	GWh	4,514	5,242	6,041	6,835	7,439
Load shedding	GWh	-	111	-	-	-
Storage energy	GWh	-	129	219	249	224
Energy Generation	GWh	4,514	5,371	6,260	7,084	7,663
Share of indigenous energy	% of total	40%	87%	93%	93%	94%

Item	Unit	2021	2025	2030	2035	2040
Share of imports	% of total	60%	17%	7%	7%	6%
Share of RES	% of total	33%	83%	72%	75%	77%
Costs						
NPV of total costs	mN$	55,639				
GHG emissions	thousands t CO_{2e}	8,259[65]				

Source: ECA analysis

The model has, in this case, chosen load shedding in 2025. This is because Van Eck power plant is assumed to be decommissioned in 2024 and some of the import contracts are assumed to end by then. The model has chosen load shedding in preference to signing long-term import contracts or building other capacity that would only be needed for a short period of time. In reality NamPower could potentially postpone the retirement of Van Eck temporarily if there were a serious risk of load shedding or extend the import contracts for a year or two.

The selection of the plant as part of the plan for Namibia to meet its domestic needs would, however, be strictly contingent on:

- the price and whether this price is competitive with alternatives,
- some certainty over the availability of the natural gas,
- willingness of the Government to accept the higher GHG emissions.

Note too that the capacity, in 50 MW blocks or other sizes, could be contracted by contestable customers through the MSB market and would not be restricted to NamPower.

Generation capacity

The total new least cost domestic generation capacity selected in the base case plan over the period 2022-2040 is 2,836 MW. The import contracts are again not renewed in this scenario and no new candidate import option is selected.

The key difference between this scenario and the base case is that the costs are slightly lower by N$ 550 million and the CO_2e emissions are significantly higher at 8.3 million tonnes.

The table below shows the technologies selected as least cost options and the amount of capacity commissioned for each technology in each year. The key differences here are that wind investment is significantly lower (1,036 MW rather than 1,546 MW) and solar PV investment is slightly higher. The latter has increased because of the firm power provided by the Kudu plant, though it may have implications for the contract. Kudu's capacity factor is

[65] Emissions from that part of the capacity allocated to supplying the Namibian market. There would additionally be greenhouse gas emissions from the remainder of the 450 MW plant that would be for export but the emissions would still be attributed to Namibia.

calculated by the model at an average of 62%. BESS investment would be lower if Kudu were developed (at 550 MW rather than 650 MW in the base case).

Table 33 Selected new capacity added each year – base case with Kudu scenario (MW)

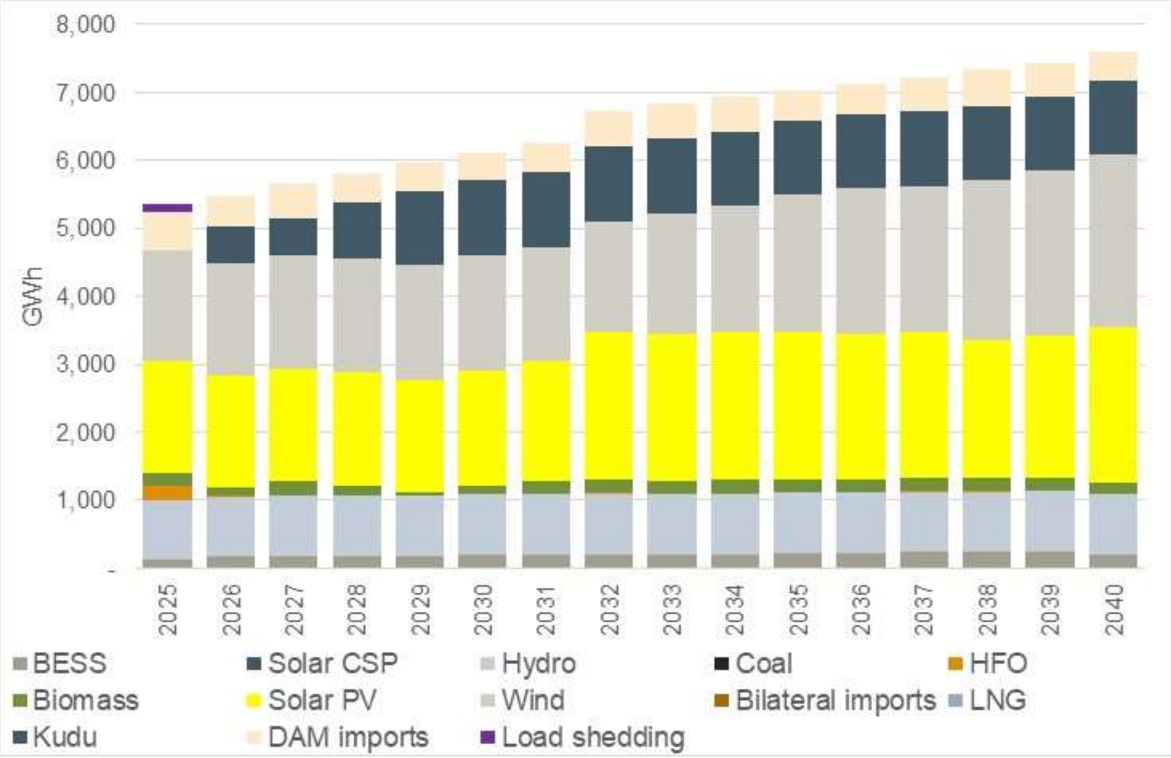
Fuel	BESS	HFO	Natural gas	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Kudu gas*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
2022 - 2030	450	50	200	40	613	570
2031 - 2035	100	-	-	-	150	220
2036 - 2040	-	-	-	-	230	170
Total	550	50	200	40	1,036	960

Source: ECA Analysis

Generation (GWh) by year

Figure 26 shows the generation mix by year. This shows that Kudu output largely displaces wind. A low number of unserved hours appears in 2025 due to coal decommissioning. This means it is more economical to invest in slightly less RES before 2026, in order to provide base-load power with Kudu in 2026.

Figure 29 Generation by year – base case (+Kudu)



Source: ECA analysis

7.5 Base-load power plant scenario

The input assumptions to this scenario are identical to the base case except that some of the capacity and energy has to be met by a large base-load power plant. Other than Kudu, the only option that is available is a 150 MW CSP plant with storage. Other base-load options such as coal-fired plants are not available because of Namibia's climate change commitments.

The model is offered a solar CSP with a net capacity of 135 MW with 2025 as earliest commissioning date. A summary of the main results is provided in the table below.

Table 34 Summary of results – base-load power plant scenario

Item	Unit	2021	2025	2030	2035	2040
Capacity						
Peak demand	MW	737	870	1,011	1,161	1,243
Energy						
Energy demand	GWh	4,514	5,242	6,041	6,835	7,439
Storage energy	GWh	-	114	206	268	268
Energy Generation	GWh	4,514	5,356	6,246	7,103	7,797
Share of indigenous energy	% of total	40%	91%	92%	94%	94 %
Share of imports	% of total	60%	9%	8%	6%	6%
Share of RES	% of total	33%	88%	89%	90%	91%
Costs						
NPV of total costs	mN$			63,575		
GHG emissions	thousands t CO_{2e}			1,432		

Source: ECA analysis

Generation capacity

The total new least cost domestic generation capacity selected in this scenario over the period 2021-2040 is 2,971 MW (266 MW committed and 2,705 MW candidate). No import contracts or other large power plants than the CSP (LNG or hydro) are selected in this scenario.

The key difference between this scenario and the base case is that the costs are higher at N$ 63.6 billion and the CO_2e emissions are lower (down by 4,600 tonnes compared with the base case).

The table below shows the technologies selected as least cost options and the amount of capacity commissioned for each technology in each year. The key differences with the base case are that both wind and solar investment are somewhat lower (-60 MW of wind, -120 MW of solar and -100 MW of BESS compared to the base case). The reliance on both sources is reduced because of the assumed commissioning of the 135 MW CSP power plant and its contribution to supplying base-load power.

Table 35 Selected new capacity added each year – base-load power plant scenario (MW)

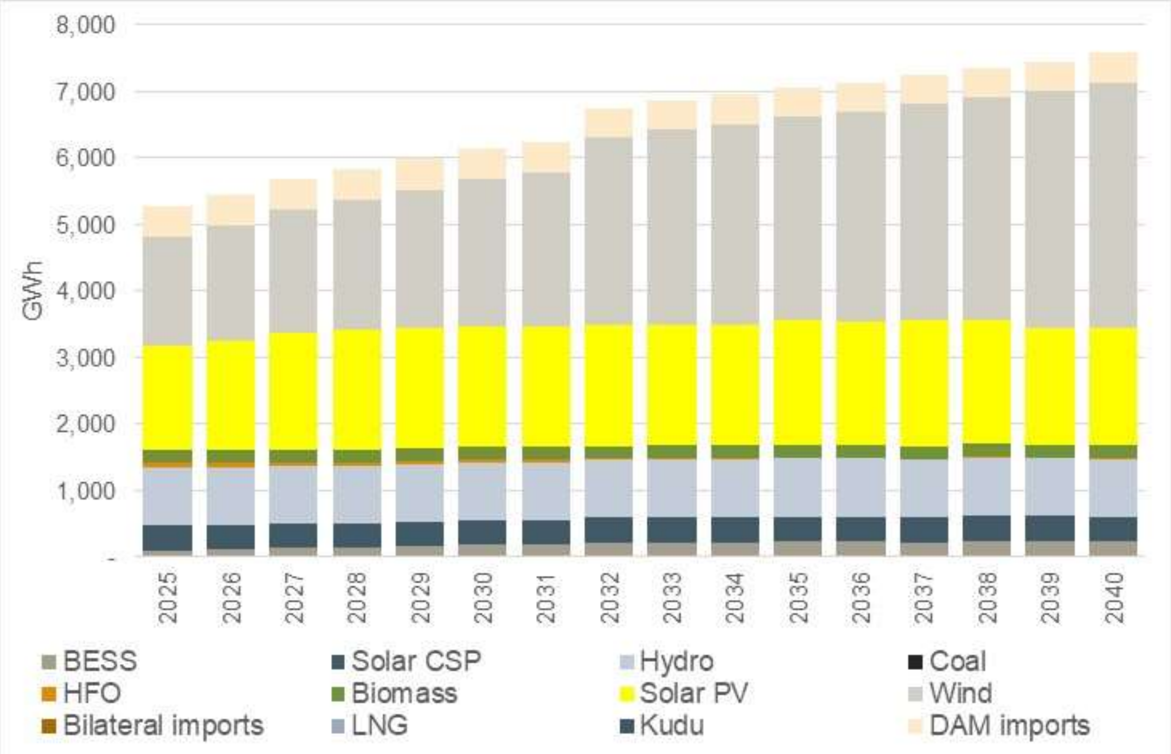
Fuel	BESS	HFO	Base-load plant	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Solar CSP*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
2022 - 2030	450	50	135	40	896	630
2031-2035	100	-	-	-	340	20
2036-2040	-	-	-	-	250	60
Total	550	50	135	40	1,486	710

Source: ECA Analysis

Generation (GWh) by year

Figure 30 shows the generation mix by year. Some solar PV and wind generation is displaced with the output from the solar CSP plant. The system is also less reliant on BESS to cope with intermittency given the storage embedded in the solar CSP plant.

Figure 30 Generation by year – base-load power plant scenario



Source: ECA analysis

7.6 No self-sufficiency constraint scenario

This scenario is a variation on the base case in which there is no requirement to satisfy the 80% self-sufficiency target. This scenario investigates whether non-indigenous energy sources would be selected as least cost if the self-sufficiency policy constraint had not been applied.

A summary of the main results is provided in the table below. There is no substantial change in this scenario in terms of investment compared to the base case. **This shows that prioritising domestic generation is already least cost and the policy constraint has virtually no impact on the least cost supply choices**[66]. This scenario also yields slightly lower CO_2e emissions.

Table 36 Summary of results – no self-sufficiency constraint

Item	Unit	2021	2025	2030	2035	2040
Capacity						
Peak demand	MW	737	870	1,011	1,161	1,243
Energy						
Energy demand	GWh	4,514	5,242	6,041	6,835	7,439
Storage energy	GWh	-	141	207	283	301
Energy Generation	GWh	4,514	5,383	6,248	7,118	7,741
Share of indigenous energy	% of total	40%	91%	91%	92%	94%
Share of imports	% of total	60%	9%	9%	8%	6%
Share of RES	% of total	33%	88%	87%	89%	90%
Costs						
NPV of total costs	mN$			56,223		
GHG emissions	thousands t CO_{2e}			1,418		

Source: ECA analysis

Generation capacity

The table below shows the technologies selected as least cost and the amount of capacity commissioned in each year. The relaxation of the self-sufficiency does not impact the attractiveness of the combination of RES and storage investments. The only difference compared to the base case is a small change to the timing of investments.

[66] The present-valued costs are actually slightly higher in this scenario compared with the base case. Normally the present valued costs without a constraint should be equal to or lower than the scenario with a constraint. We believe that the difference is due to small rounding errors.

Table 37 Selected new capacity added each year – no self-sufficiency target (MW)

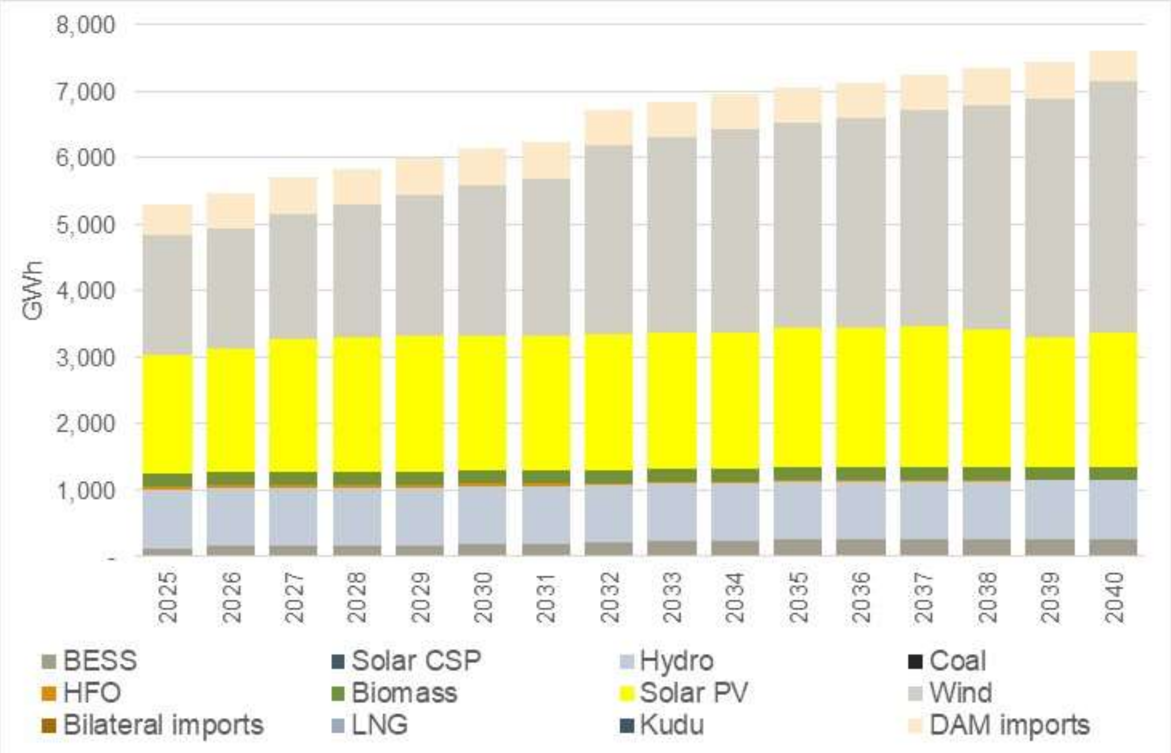
Fuel	BESS	HFO	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
2022 - 2030	500	50	40	936	730
2031 - 2035	150	-	-	330	30
2036 - 2040	-	-	-	280	70
Total	650	50	40	1,546	830

Source: ECA Analysis

Generation (GWh) by year

Figure 31 shows the generation mix by year. The annual dispatch is identical to the base case.

Figure 31 Generation by year – no self-sufficiency constraint



Source: ECA analysis

7.7 Accelerated RES scenario

The accelerated RES scenario identifies the least cost generation plan that would satisfy the demand forecast under the restriction that 70% of generation has to be covered by renewable energy sources (hydro, solar, wind and biomass) by 2026 instead of 2030. This scenario looks into the implication of reaching RES targets four years ahead of stated policies. This constraint does not impose any limits on the amount of energy that can be imported to Namibia but *de facto* limits it to a maximum of 30% as of 2026. A summary of the main results is presented in the table below.

Table 38 Summary of results – accelerated RES

Item	Unit	2021	2025	2030	2035	2040
Capacity						
Peak demand	MW	737	870	1,011	1,161	1,243
Energy						
Energy demand	GWh	4,514	5,242	6,041	6,835	7,439
Storage energy	GWh	-	143	229	285	301
Energy Generation	GWh	4,514	5,386	6,270	7,120	7,741
Share of indigenous energy	% of total	40%	89%	91%	92%	94%
Share of imports	% of total	60%	11%	9%	8%	6%
Share of RES	% of total	33%	86%	88%	89%	90%
Costs						
NPV of total costs	mN$			56,275		
GHG emissions	thousands t CO_{2e}			1,418		

Source: ECA analysis

Generation capacity

The table below shows the technologies selected as least cost and the amount of capacity commissioned for each technology in each year.

The total new generation capacity installed over the period 2021-2040 is 3,116 MW (839 MW of solar capacity, 1,460 MW of wind, and 650 MW of BESS). This is very similar to the base case. The key difference with the base case relates to the timing of investments: Solar PV and BESS are required sooner to meet the 70% RES generation target in 2026.

Table 39 Selected new capacity added each year – accelerated RES (MW)

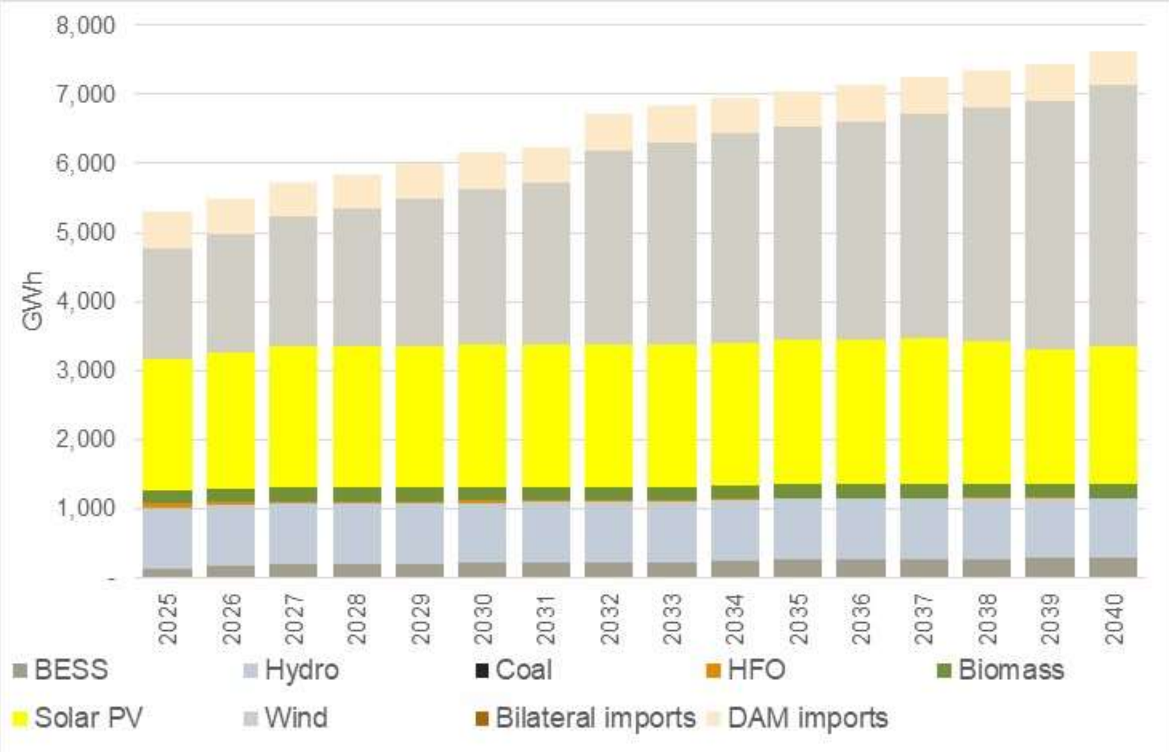
Fuel	BESS	HFO	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
2022 - 2030	550	50	40	936	740
2031 - 2035	100	-	0	330	20
2036 - 2040	-	-	-	280	70
Total	650	50	40	1,460	830

Source: ECA Analysis

Generation (GWh) by year

Figure 32 shows the generation mix by year. In 2021. As with the base case, the mix is dominated by solar and wind as of 2026. The remaining gap is filled by Ruacana hydro and bilateral imports. Wind takes an increasing role in meeting the RES targets with the largest annual additions after 2030. Wind generation partly replaces current bilateral imports in 2026 as these are not prolonged. Domestic thermal power plants are only running marginally until 2024. Anixas I and II only run for a few hours per year as of 2026, and the utilisation slowly decreases until 2040 (their combined capacity factor decreases from approximately 6% in 2026 to 1% in 2040).

Figure 32 Generation by year – accelerated RES



Source: ECA analysis

7.8 Large power plants scenario

This scenario looks at the implications for Namibia if:

- the Kudu gas plant is ready for production in 2026 and 250 MW of the output will be available to Namibia at prices competitive with imports, and
- the 300 MW Baynes hydropower plant is ready for dispatch 2031.

The timing of Kudu is based on its earliest commissioning date and the timing of Baynes is determined to satisfy the power system's reserve requirement (and system reliability).

Table 40 Summary of results – large power plants

Item	Unit	2021	2025	2030	2035	2040
Capacity						
Peak demand	MW	737	870	1,011	1,161	1,243
Energy						
Energy demand	GWh	4,514	5,242	6,041	6,835	7,439
Storage energy	GWh	-	122	214	228	230
Energy Generation	GWh	-	5,364	6,254	7,063	7,670
Share of indigenous energy	% of total	40%	89%	91%	92%	93%
Share of imports	% of total	60%	11%	9%	8%	7%
Share of RES	% of total	33%	73%	65%	69%	72%
Costs						
NPV of total costs	mN$	57,788				
GHG emissions	thousands t CO_{2e}	10,949				

Source: ECA analysis

Generation capacity

The table below shows the technologies selected as least cost and the amount of capacity commissioned for each technology. Alongside Kudu (250 MW) in 2026 and Baynes (300 MW) in 2031, two OCGTs are required in 2025 to supply the system peak demand in that year. Beyond 2025, the commissioning of Kudu and Baynes leads to a lower reliance on wind (approximately 960 MW less than in the base case) and, to a lesser extent, BESS (approximately 150 MW less) and solar (approximately 130 MW less).

Table 41 Selected new capacity added each year – large power plants scenario (MW)

Fuel	BESS	HFO	Hydro	Natural gas	Natural gas	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Baynes*	*Kudu gas*	*OCGT*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
2022 - 2030	450	50	-	250	84	40	436	570
2031 - 2035	50	-	300	-	-	-	-	30
2036 - 2040	-	-	-	-	-	-	150	230
Total	500	50	300	250	84	40	586	830

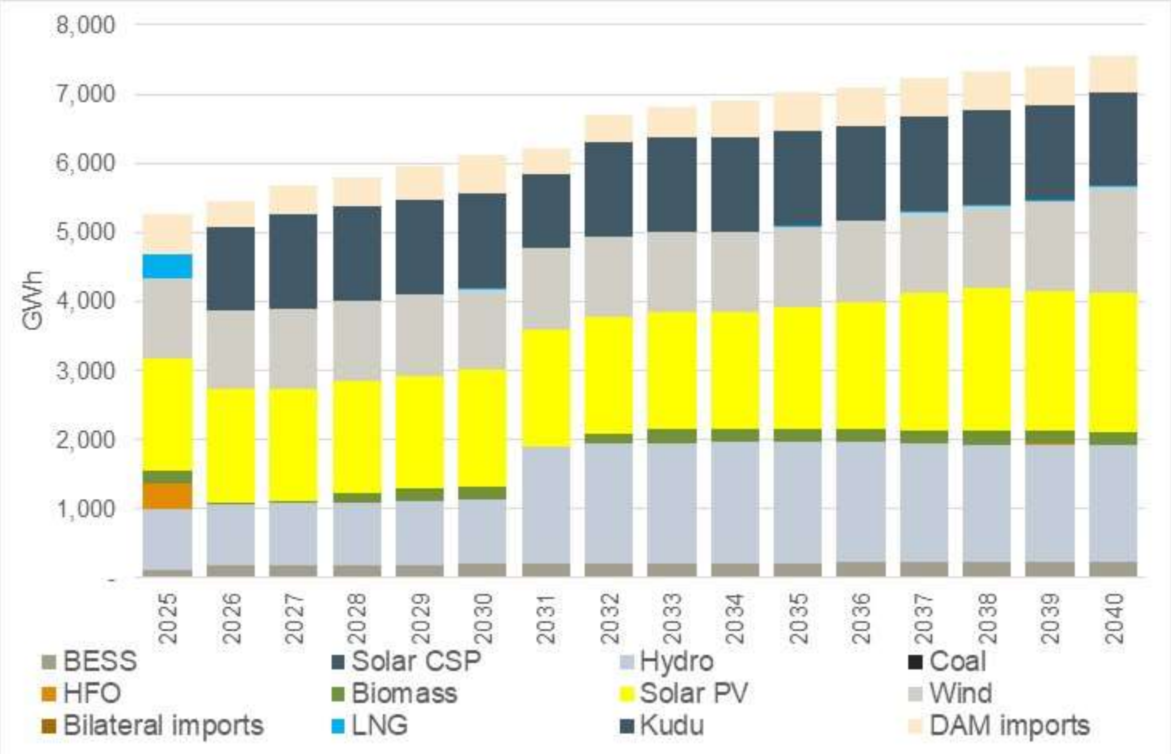
Source: ECA Analysis

Generation (GWh) by year

Figure 33 shows the generation mix by year. The figure shows that:

- Until 2024, bilateral and DAM imports are used to meet base-load supply together with Ruacana hydro.
- 2025 is a transition year in this analysis where bilateral import contracts were originally expected to end[67]. A higher utilisation of Anixas I & II would help to satisfy demand, but these plants are insufficient by themselves and a gap would emerge without investment. The model unrealistically chooses LNG and small peaking OCGT units. While developing LNG import facilities by 2025 is theoretically feasible, given the low volumes of LNG imported to meet the peak and the low capacity factors after 2025[68], it would be more realistic to prolong some of the bilateral import contracts and/or prolong Van Eck for one year. Alternatively, this could potentially be regarded as one of the Kudu units that is run on LFO in 2025 until the Kudu field is developed.
- From 2026, Kudu, Ruacana and Baynes would provide base-load power in this scenario.

Figure 33 Generation by year – large power plants



Source: ECA analysis

67 Subsequently extended to 2027 but this occurred after input assumptions were finalized.
68 See footnote 67. These have been extended 2027.

7.9 Unconstrained scenario

The unrestricted least cost scenario identifies the least cost generation plan without any restrictions on the amount of domestic capacity or imports and without the renewable energy targets (i.e., no policies are implemented and only the least cost options are chosen).

In this scenario, the total additional capacity reaches 3,116 MW by 2040, which is identical to the base case and self-sufficiency scenarios. As with the base case scenario, the model chooses solar PV, wind, and BESS as the least cost options to satisfy demand on top of announced committed power plants.

Table 42 Summary of results – Unconstrained

Item	Unit	2021	2025	2030	2035	2040
Capacity						
Peak demand	MW	737	870	1,011	1,161	1,243
Energy						
Energy demand	GWh	4,514	5,242	6,041	6,835	7,439
Storage energy	GWh	-	143	207	283	301
Energy Generation	GWh	4,514	5,386	6,248	7,118	7,741
Share of indigenous energy	% of total	40%	89%	91%	92%	94%
Share of imports	% of total	60%	11%	9%	8%	6%
Share of RES	% of total	33%	86%	87%	89%	90%
Costs						
NPV of total costs	mN$			54,172		
GHG emissions	thousands t CO_{2e}			1,436		

Source: ECA analysis

Generation capacity

The table below shows the technologies selected as least cost and the amount of capacity commissioned each year.

Table 43 Selected new capacity – unconstrained scenario (MW)

Fuel	BESS	HFO	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
2022 - 2030	500	50	40	936	730
2031 - 2035	150	-	-	330	30
2036 - 2040	-	-	-	280	70

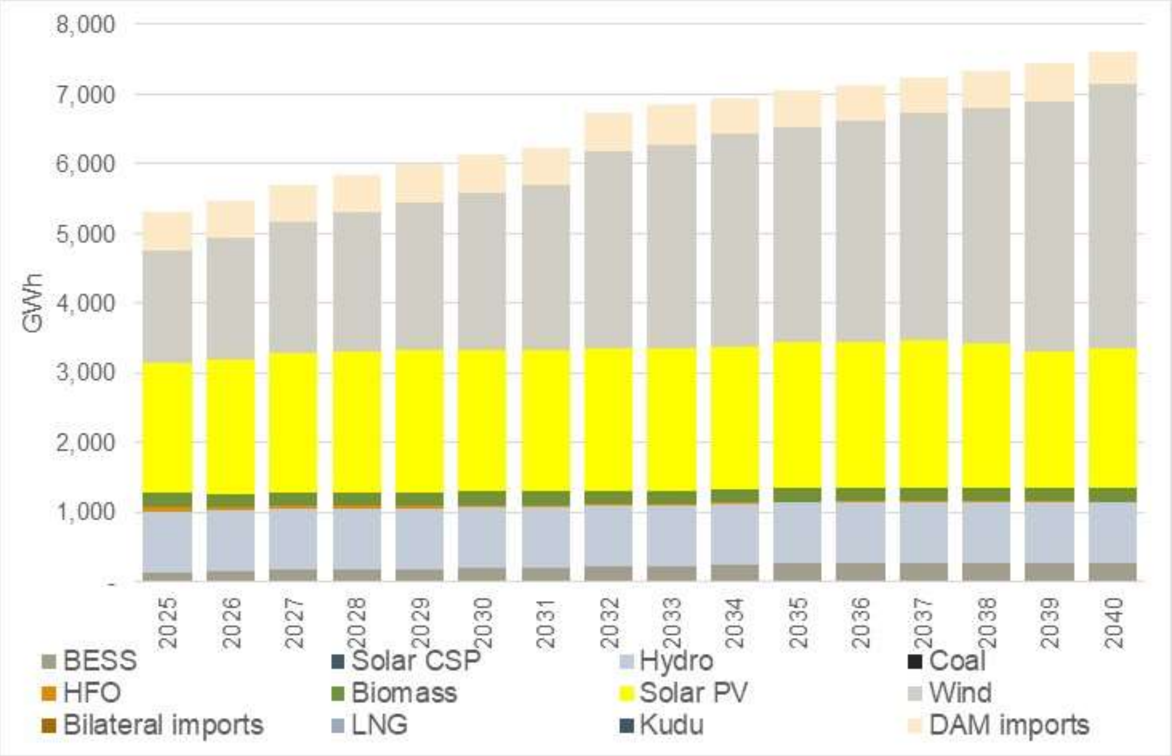
Fuel	BESS	HFO	Biomass	Wind	Solar PV
Plant name(s)	*Omburu & generic plants*	*Anixas II*	*Otjikoto*	*Luderitz & generic plants*	*Khan & generic plants*
Total	650	50	40	1,546	830

Source: ECA Analysis

Generation (GWh) by year

Figure 33 shows the generation mix by year.

Figure 34 Generation by year – Unconstrained



Source: ECA analysis

7.10 Sensitivity analyses

The sensitivity analyses were all conducted relative to the base case scenario. The sensitivity analyses related to demand growth (low), investment costs and national energy security targets. The sensitivity analyses were prepared to assess the implications for investment and policy choices and are described in the table below.

Table 44 Sensitivity analyses

#	Sensitivity	Description
1	Favourable import prices	This scenario considers the possibility that Namibia is able to negotiate bilateral import contracts at more favourable terms than in the base case by 20%.
2	Ceiling on intermittency	This sensitivity investigates the impact of limiting the total installed capacity from intermittent generation sources. The ceiling for intermittency is set at 60%[69] of GWh produced. This corresponds to the limit at which small's power systems are thought to be able to cope with.
3	Low demand growth	This considers the impact of alternative demand projections. In 2040, the low demand forecast scenario is 16.4% lower than the base case.
4	NamPower demand growth	This variation of the base case analyses the impact of NamPower (Transmission)'s base demand forecast. This load forecast is 30% lower than ECA low demand forecast (Sensitivity #3) in 2030.

Source: ECA

The results of these runs are summarised in the table below.

Table 45 Sensitivity analysis

Scenario:	Base case	Lower import prices	Ceiling on Intermittent energy	ECA Low demand growth	NamPower Base demand forecast
Wind & solar (MW) in 2030	1,676	1,666	976	1,456	470
BESS (MW) in 2030	550	500	500	450	300
Base-load plant (type)	None	None	Baynes (2030)	None	None
RES share in 2030 (%)	87%	87%	80% (63% is intermittent)	87%	84%
Indigenous energy share in 2030 (%)	91%	91%	92%	90%	87%

[69] Ireland, as an island system, has identified solutions to integrate higher levels of non-synchronous generation. In doing so, it has set up a System Non-Synchronous Penetration (SNSP) metric which used to identify the amount of non-synchronous generation that can be permitted on the system at any one time while ensuring system stability. Following a successful trial period, the permitted SNSP in Ireland is currently 70% (*Mehigan L., Renewables in the European power system and the impact on system rotational inertia, 2020*). Given the system size in Namibia and the less sophisticated reserve market, we have assumed 60% as an intermittency ceiling for this sensitivity analysis.

Scenario:	Base case	Lower import prices	Ceiling on Intermittent energy	ECA Low demand growth	NamPower Base demand forecast
Present value costs (N$ mn)	**56,189**	**56,143**	**58,429**	**49,509**	**38,295**
CO_2e (tonnes)	1,436	1,436	1,304	1,403	1,477

Source: ECA Analysis

The sensitivity analysis suggests the conclusions are robust to the assumptions:

- A lower demand growth leads to similar conclusions regarding the central position of wind and solar in meeting demand. This is also confirmed with running NamPower base scenario forecast.
- Even if Namibia is able to negotiate lower bilateral import prices, RES continues to be chosen as the least cost solution.
- If early results from increased penetration of intermittent RES reveal problems, and a ceiling of 60% is placed on intermittent RES, the alternative that would achieve the RES target (70% by 2030) and the self-sufficiency target (80% by 2030) is Baynes hydro.

8 Conclusions and next steps

8.1 Conclusions

The capacity additions, present-valued system-wide costs, RES share, energy self-sufficiency share, and CO_2e emissions for the selected scenarios are summarised in the table below.

Table 46 Capacity additions by scenario to 2040 (MW unless otherwise specified)

Scenario	1	1a	2	3	4	*5*	*6*
Power plants	**Base case**	**Base case (+Kudu gas)**	**Forced base-load plant**	**No self suffi-ciency target**	**Acceler-ated RES**	Large power plants	Uncons-trained
Hydro	-	-				300	-
Natural Gas	-	200	-	-	-	250	-
LNG	-	-	-	-	-	84[70]	-
HFO	50	50	50	50	50	50	50
Wind	1,546	1,036	1,486	1,546	1,546	586	1,546
Solar	830	960	710	830	830	830	830
Solar CSP		-	135			-	
Biomass	40	40	40	40	40	40	40
BESS	650	550	550	650	650	500	650
Imports	-	-	-	-	-	-	-
Total (without committed capacity)	2,850	2,570	2,705	2,850	2,850	2,374	2,850
Total (with committed capacity)	3,116	2,836	2,971	3,116	3,116	2,640	3,116
Present value costs (N$ mn.)	**56,189**	**55,639**	**63,575**	**56,233[71]**	**56,275**	**57,788**	**54,172**

[70] 2 x 42 MW open-cycle gas turbines. These units are chosen by the optimization algorithm in order to avoid load shedding in 2025 following the assumed closure of the Van Eck power plant at the end of 2024, and before the commissioning of the Kudu gas-fired power plant in 2026. In practice it is likely that the closure would be postponed or import contracts would be extended or some other solution would be found to bridge the supply gap in 2025.

[71] The present-value costs should be greater than or equal to those in the base case. The difference of less than 0.1% is within the tolerance of the modelling optimization algorithm.

Scenario	1	1a	2	3	4	5	6
Power plants	**Base case**	**Base case (+Kudu gas)**	**Forced base-load plant**	**No self suffi-ciency target**	**Acceler-ated RES**	Large power plants	Uncons-trained
RES share in 2030	87%	72%	89%	87%	88%	65%	87%
Self-sufficiency in 2028	90%	93%	92%	90%	91%	93%	90%
Total CO_2e (tonnes)	1,436	8,259	1,432	1,418	1,418	10,949	1,436

Source: ECA Analysis

The least cost investment sequences for all seven of the scenarios point to the attractiveness of solar PV and wind energy technologies, combined with BESS. As described below, Scenarios 1, 3, 4 and 6 all suggest that the technologies with the lowest economic cost would also satisfy and exceed the policy targets of 70% penetration of RES (whether by 2030 or by 2026) and 80% self-sufficiency (by 2028). In other words, it is not necessary to incur additional costs in order to achieve these policy targets. The solar PV and wind resources could be developed by NamPower, by the private sector to supply the national market, or by the private sector to supply the international market with some allocated to the domestic market (e.g., the mega projects). The NIRP does not differentiate between developers.

None of the scenarios choose power plants using new hydropower unless they are forced in (scenario 5). However, in one of the sensitivity studies in which a ceiling of intermittent RES of 60% of generation is introduced, Baynes would be chosen, primarily to allow the 70% RES target to be satisfied.

Scenario 1a is representative of an export-oriented power plant and shows, unsurprisingly, that if the Kudu gas-fired power plant, or any export-oriented plant, could supply electricity to the Namibian market at prices lower than those available from SAPP, then it would be economically attractive for the Namibian market (NamPower and/or the contestable market) to buy that power (scenario 1a compared with scenario 1). The onus would be on the developers of the export-oriented plant to demonstrate that they can supply some of the power from the export plant at these price levels.

RES energy targets are easily satisfied. The 70% RES energy penetration target is achieved by 2025 without the imposition of policy constraints. Only if the Kudu gas-fired power plant is developed for export and some of that power is diverted to Namibia (scenario 1a) or if the large power plant scenario (scenario 5) is followed, which also includes Kudu gas-fired power plant, would it be necessary for MME to intervene to ensure that the 70% target is achieved[72].

Self-sufficiency targets can also be easily satisfied. Because the most economically attractive options available to Namibia generally involve the development of indigenous

[72] The output of the Kudu gas-fired plant would need to be kept below its capacity in order to satisfy the RES target.

renewable power, the investment plans generally satisfy the 80% self-sufficiency target even without introducing this as a policy constraint.

GHG emissions will be very low. Emissions of greenhouse gases essentially follow the same pattern as RES penetration discussed above. CO_2e emissions from power generation would fall from already low levels[73] to almost insignificant levels by 2025. The introduction of the Kudu gas-fired power plant in 2026 in two of the scenarios would, however, increase emissions of greenhouse gases associated with Namibian electricity supply[74].

8.2 Policy and investment choices and next steps

When making policy decisions relating to energy sustainability, most countries face trade-offs between sustainability, reliability and affordability. Namibia appears fortunate in having energy resources that allow all of these pillars to be aligned, with the least cost energy sources also being environmentally attractive. Because these sources are least cost, they allow electricity to be supplied to users at lower cost than alternatives and are therefore good for Namibia's economy and for end users.

The timing of the investments will depend on how load growth progresses, what demand-side or energy efficiency measures are implemented and what behind-the-meter technologies are adopted by consumers. The NIRP focuses particularly on supply-side measures to serve the national grid, and while behind-the-meter technologies and demand-side programs were not ignored in the load forecast, there will be further opportunities for implementing demand-side measures, such as solar water heating and ripple control on water heaters, that will slow growth in the load and maximum demand. There may also be a gradual switch to electricity in transport, which could increase load growth. Fortunately, the RES technologies identified in the investment plans have relatively short construction periods and this allows the investments to be matched more closely to the growth in load experienced over time, thereby avoiding surpluses and stranded investments that might occur with larger-scale investments that require longer term forecasting.

The analysis supports the base case scenario as the most appropriate investment plan for Namibia, primarily comprising a mix of wind, solar and energy storage solutions. These investments could be delivered by NamPower or the private sector through the MSB market or under contract to NamPower (the NIRP does not make recommendations regarding the developers). The NIRP leaves open the possibility that these investments could be made as part of export-oriented projects or standalone ones.

There do not appear to be difficult investment decisions in Namibia involving trade-offs between sustainability, reliability and affordability. Moreover, uncertainties over large investments that depend on the accuracy of the load forecasts do not arise because wind, solar and storage technologies have relatively short construction periods and can be

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[73] Relative to many other countries, Namibia's emissions of CO_2e from the power sector are already at very low levels.

[74] Note that this does not include greenhouse gas emissions associated with exported power from the Kudu gas-fired power plant. Such emissions would also be attributed to Namibia in conventional UN greenhouse gas accounting practices and would increase the emissions above those shown in estimated in this analysis**Error! Reference source not found.**.

developed more easily to match load growth. Nevertheless, this does not mean that there are no further policy decisions that MME must address or no issues over investments or decisions that must be made by MME, NamPower and ECB. These issues and decisions are discussed below.

8.2.1 Intermittency and a “base-load” plant

The intermittency of the RES power plants is balanced in all of the scenarios, to different degrees, by the development of BESS options which have been identified as being necessary to ensure stability. The optimisation algorithm chooses combinations of battery capacity and intermittent RES in order to exploit Namibia’s low-cost RES resources, ensure system stability and shift energy from the daytime and supply that energy in the peak evening hours. However, the assessment of the need for BESS (or other storage technologies) to ensure stability and shift energy is not yet an exact science and there will always be some uncertainty over whether the technology combinations will satisfy stability and reliability requirements. Namibia is fortunate in being able to use the SAPP grid for stability in emergencies, but Namibia’s SAPP neighbours may be reluctant to provide such support on a regular basis unless they are compensated for providing this service. Scenario 2 explores the cost implications if NamPower develops a “base-load” power plant that would have a secondary role in providing stability/reliability support. The options available in this case are limited to a gas-fired power plant using indigenous gas if that resource is developed (Kudu), or imported LNG, or a CSP plant with storage.

The Kudu gas-fired power plant is modelled in **scenario 1a** and could, potentially, offer lower costs as well as enhanced system stability/reliability, but the cost hinges on the price that it will be able to offer electricity to the Namibian market. This scenario will continue to satisfy the self-sufficiency target, though the output of Kudu would need to be held (operationally) below its optimum economic output to ensure that the RES target is met. A gas-fired power plant using imported LNG initially, with a switch to Kudu gas if and when that indigenous gas is developed, would also offer system stability/reliability and could potentially offer lower costs, again depending on the cost/price of power offered from the Kudu plant (though this has not been modelled). A smaller dedicated 150 MW base-load gas-fired plant using imported LNG throughout its lifetime was shown in the screening analysis to be costly and it would violate all of the policy targets relating to RES, self-sufficiency and GHG emissions.

A CSP plant with thermal storage is not conventionally considered to be a base-load plant but storage offers the characteristics that allow it to be used to satisfy demand at short notice. The use of a CSP plant with storage as a base-load plant is analysed in **scenario 2**. This scenario has costs that are N$ 13.4 billion greater than the base case (scenario 1) in present value terms (or 13.1% greater). This is a substantial difference.

Options relating to the Kudu gas project and the CSP project remain and will remain, but Namibia is again fortunate that the modular nature of RES means that RES investments, and associated energy storage, could go ahead while further work and negotiations continue regarding Kudu and the CSP projects and while the ability of the power system to absorb intermittent power is assessed.

8.2.2 Mega projects involving RES

A number of large-scale solar or wind projects have been proposed by private developers for export of electricity, hydrogen or ammonia, or to provide cloud storage resources for use internationally. While not modelled explicitly, the generic analysis of wind and solar in NIRP 2022 suggests that the use of some of the electricity produced by these projects to supply Namibia's electricity demand should be economically attractive and, likely, financially attractive. Clearly, this would depend on the price at which the electricity is offered to NamPower or to contestable consumers from these plants.

Since investment decisions regarding the mega projects will be taken by private developers, and these are RES projects that align with Namibia's RES, self-sufficiency, NDC (GHG) and economic targets and intentions, and state financial support should not be required, there is less need for intervention by government ministries in these investments. Negotiations will be required between the developers and NamPower or contestable consumers over price and other terms if the developers wish to sell them their surplus output. The projects will need to be licenced by ECB in accordance with the current legislation and regulations. Other normal permits, including environmental and land-use, will also be required.

8.2.3 The competitive market and ancillary service requirements

While analysis shows that BESS should be developed to balance the intermittent RES that has been identified in the NIRP as economically attractive, it does not follow that the market and pricing arrangements for the services provided by BESS will attract sufficient BESS. This suggests that the market framework should be reviewed to ensure that participants in the MSB market properly contribute to the cost of providing ancillary services and that providers of BESS services (whether NamPower or the private sector) are properly remunerated for providing ancillary services. Pricing arrangements for non-contestable customers (the non-contestable market) should also be reviewed to ensure that NamPower and its non-contestable customers are not burdened with the cost of providing these services, thereby distorting the market.

8.2.4 Licensing of RES and geospatial dimensions

While solar PV can often be located in parts of the network that avoid the creation of transmission bottlenecks and increased transmission losses, there will be concerns over the ability of the transmission grid to transport power from those parts of the country with the best wind energy resources to the load centres. The NIRP analysis did not specifically consider the geospatial aspects of new power generation investment, but note that the co-location of BESS with wind generation (or large solar parks) may help resolve constraints on the operation of the networks. Further investigation will certainly be needed to determine the impact on network development costs and transmission losses associated with large wind and solar projects.

A1 How the NIRP might be used by stakeholders

The following illustrates how the NIRP might be used and for what purpose by the various stakeholders.

What issues or decisions?	Entities that may use the NIRP MME	NamPower (NP)	ECB	Private sector investors	Private citizens
	(Role of the entity: how the NIRP will be used for this purpose)				
Decide which investments NP should undertake on balance-sheet and IPP contracting	**Governance role**: MME must review and approve/reject NP's investment plan and will take account of information in the NIRP to do so	**Request approval from Minister for NP investments**: Prepare an investment plan/contracting plan for NP to submit to MME for approval. The plan takes account of findings of NIRP			**Open government:** Allows private citizens to understand investment decisions
------- " ---------		**Request approval for tariffs**: In its tariff submission, NP to use NIRP to justify NP's capital expenditure/asset base and some operating costs (eg., purchases from IPPs)	**Review and approve tariff proposals by NP**: Use NIRP to confirm that capex projects are least-cost		**Open government:** Allows private citizens to understand tariff approval decisions
MSB market design		**MSB market design:** NIRP helps with identifying potential investments that may require MSB design amendments (e.g., for BESS or ancillary services to support intermittent RES)	**MSB market design:** NIRP helps with identifying potential investments that may require MSB design amendments (e.g., for BESS or ancillary services to support intermittent RES)	**Help identify potential future opportunities in the MSB market components (e.g., ancillary services):** The NIRP may highlight opportunities that allow the private sector to position itself for future tenders	
Environmental, economic and security policy assessment and design	**Policy impact assessment**: NIRP indicates possible cost and emission consequences and other trade-offs of policies being considered				**Open government:** Allows private citizens to understand policy tradeoffs
Energy security policy design	**Policy design**: the NIRP may identify concerns over supply robustness (intermittent generation, hydrological uncertainty, primary energy security, etc) that may require policy action				**Open government:** Allows private citizens to understand policy concerns
Which projects should the private sector undertake?	**Policy role**: By determining which projects NP should undertake, MME is implicitly making a policy decision about which opportunities it wishes to leave to the private sector			**Help identify potential future opportunities in the MSB market:** Although the NIRP does not show NP projects, the Ministerial Decisions should flow from it	
------- " ---------				**Help identify potential future IPP opportunities:** Although the NIRP does not shown NP's IPP projects, these should flow from it	
Shaping the IPP contracts		**Capacity/energy or take-or-pay components of tariffs with IPPs**: Use NIRP to assess position in merit order and whether the plant should be contracted to provide base load, mid-merit or peaking	**Reviewing contract terms**: If ECB is responsible for approving prices in contracts signed with NP, the NIRP would help inform that review	**Understanding the potential role of IPP and MSB projects in the market:** The NIRP gives an indication of the position of the various technologies in the market	
Geospatial decisions	**Policy role**: In considering energy security, MME may wish to encourage certain locations or location policies and the NIRP will help understand whether this is necessary	**Network planning and optimisation**: NP will use the NIRP to understand potential problems with network bottlenecks	**Network tariff design**: Consider whether tariffs should be designed to encourage investments in certain locations		

A2 Load forecast report

A2.1 Introduction

The Load Forecast Report was prepared by ECA, supported by MCS, as part of the IRP Update study. The report was prepared during the first few months of 2021 in the middle of the Covid-19 pandemic and approved in May 2021.

The aim of the report is to update the load forecast to reflect new developments since the 2016 NIRP. In particular the economic growth and mining loads that were forecast at the time the 2016 NIRP did not materialise.

Since the 2016 NIRP, the MSB model has been introduced so that some of the market will be supplied directly by IPPs selling power to contestable consumers over the national transmission network. Nevertheless, the NIRP continues to be concerned with the optimal investment needed to satisfy the total market including that part of the market supplied by IPPs. The load forecast that is of interest therefore continues to be the national electricity load irrespective of the source of the generation that supplies that load.

The NIRP concerns generation to supply grid-connected consumers but needs to be aware of and take account of the national electrification plans and the plans to connect off-grid households to the grid over time.

A2.1.1 Structure of the electricity market

Namibia power Corporation (Pty) Ltd (NamPower) is the national power company owned by the Namibian Government and the dominant player in the electricity market, responsible for generation, transmission, partial distribution and trading of electricity. The distribution network is also served by five REDs: CENORED, Central Zone, Erongo, NORED and Southern Zone.

The electricity sector is currently undergoing a major reform associated with the implementation of the MSB framework. The MSB was introduced in 2019 to encourage private investment and competition in the sector. Under phase 1a of the MSB model, IPPs connected or to be connected to the national transmission grid are allowed to contract directly with transmission customers, supplying up to 30% of their energy demand, subject to available grid capacity.

A2.2 Load forecasting – background

A2.2.1 Historical load growth

Historical load figures have been combined using the 2016 IRP study (up to 2016) and NamPower's annual reports (2016-2019). The figures are collected on a fiscal year basis, from July to June each year. Total units sold include NamPower's sales to distribution companies and direct suppliers, such as mines and water pumping schemes. The average annual growth rate of total units sold between 1989 and 2019 was 3.1%.

Table 47 Historical load data

Fiscal year	Units sent out (GWh)[75]	Total units sold (GWh)[76]	Units exported (GWh)	Units to Orange River[77] (GWh)	Units to Skorpion (GWh)	Units sold in Namibia (GWh)	Apparent Transm-ission losses[78]
1989	1,835	1,659	267			1,392	10%
1990	1,790	1,612	166			1,446	10%
1991	1,919	1,719	201			1,518	10%
1992	1,948	1,714	204			1,510	12%
1993	1,746	1,551	49			1,502	11%
1994	1,753	1,553	28			1,525	11%
1995	2,015	1,784	146			1,638	11%
1996	1,951	1,731	30			1,701	11%
1997	1,949	1,700	1			1,699	13%
1998	2,211	1,904	21			1,883	14%
1999	2,085	1,863	56			1,807	11%
2000	2,192	1,978	100			1,878	10%
2001	2,277	2,050	69			1,981	10%
2002	2,371	2,136	54			2,082	10%
2003	2,466	2,246	53		76	2,117	9%
2004	2,945	2,795	23	257	471	2,044	7%
2005	3,363	2,976	31	206	596	2,143	15%
2006	3,554	3,199	36	184	682	2,297	13%
2007	3,621	3,259	40	191	629	2,399	13%
2008	3,719	3,392	47	224	663	2,458	12%
2009	3,692	3,358	68	122	639	2,529	11%
2010	3,767	3,431	77	130	673	2,551	11%
2011	3,910	3,543	76	127	690	2,650	12%
2012	4,162	3,726	91	133	662	2,840	13%
2013	4,238	3,861	89	139	647	2,986	11%

[75] Units sent-out are total units entering the transmission system
[76] Total units sold is calculated as the sum of power sales in Namibia, exports and sales to Orange River and Skorpion
[77] Orange River supply points are directly connected to Eskom's network
[78] Until 2002, transmission losses are calculated according to the formula: 1 – (total units sold/units sent out). The methodology for calculating transmission losses in later years is not clear.

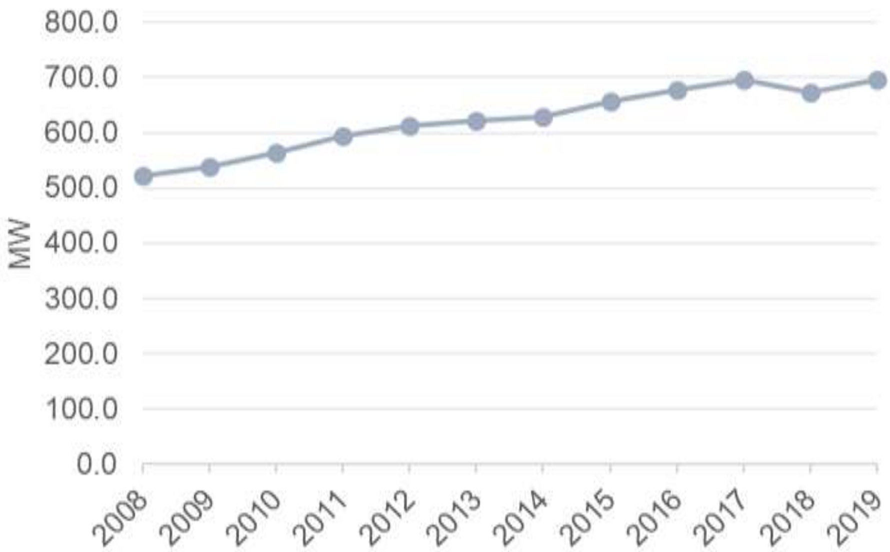
Fiscal year	Units sent out (GWh)[75]	Total units sold (GWh)[76]	Units exported (GWh)	Units to Orange River[77] (GWh)	Units to Skorpion (GWh)	Units sold in Namibia (GWh)	Apparent Transm-ission losses[78]
2014	4,384	3,827	84	145	571	3,027	15%
2015	4,254	3,870	88	139	474	3,169	11%
2016		4,008					
2017		4,157					10%
2018		4,285					14%
2019		4,159					9%
AAG	3.3%	3.1%	-4.2%	-5.4%	16.5%	3.2%	

Source: 2016 IRP; NamPower's 2019 Annual Report

Additionally, NamPower provided ECA with a time series of historical peak demand (Figure 35; calculated on a calendar year basis) and historical energy demand (Figure 36, reported on a financial year basis). The system maximum demand in 2019 was 720 MW (including Skorpion Zinc Mine).

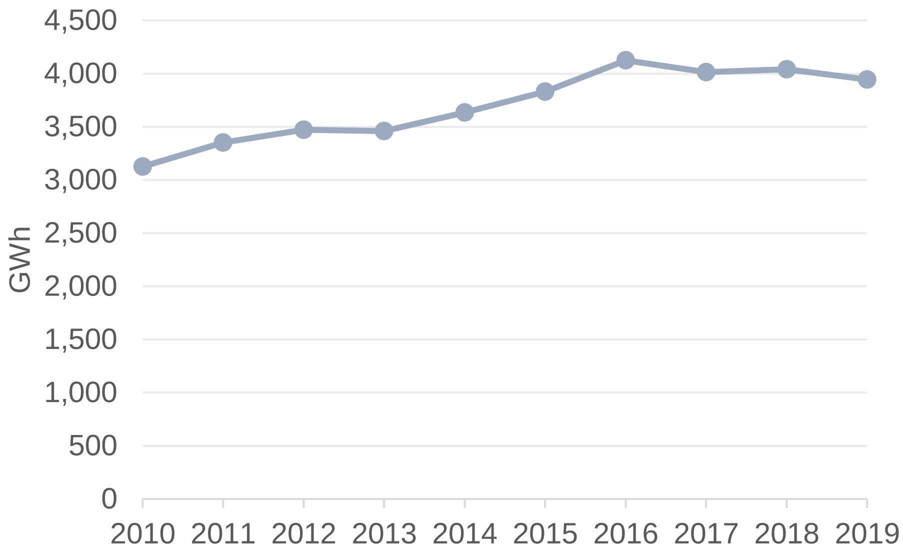
We note inconsistencies in the data in the 2016 NIRP and the NamPower Annual Reports and inconsistencies between the data in Table 47 and the data in Figure 36 and Table 48. that were provided by NamPower. The inconsistencies are noted but they are small and will not materially affect the results of the study. Some of the data discrepancies may be explained if consumed energy was measured at different points of supply chain - the difference between the measurement at the point of supply and the point of delivery should be equal to network losses.

Figure 35 Historical peak demand 2010-2019



Source: NamPower; response to data request dated 06/08/2020

Figure 36 NamPower's historical energy demand (2010-2019)



Source: NamPower; response to data request dated 06/08/2020

A high-level split of energy sales is provided in Table 48. Between 2008 and 2019, energy sales grew by 3.25% on average. Close to 90% of energy was sold to TOU customers.

Table 48 Break down of historical energy sales

Year	TOU sales	Non-TOU sales	Export	Total
2008	2,337	187	47	2,572
2009	2,393	199	68	2,661
2010	2,414	172	37	2,623
2011	2,467	246	38	2,751
2012	2,655	254	50	2,959
2013	2,778	280	52	3,110
2014	2,782	285	46	3,113
2015	2,941	279	70	3,291
2016	3,097	287	62	3,447
2017	3,219	276	84	3,578
2018	3,336	280	92	3,708
2019	3,271	289	99	3,658

Source: NamPower; response to data request dated 06/08/2020

A2.2.2 National electrification rate

The World Bank publishes a time series of the national electrification rate split between rural and urban population (Table 49). Access to electricity in this study is defined as the percentage of population with access to electricity but not necessarily with a grid connection. Data are collected from nationally representative household surveys, national censuses, demographic and health surveys and other industry and international sources[79]. Table 49 presents the data for Namibia where electricity access rate increased by an average of one percentage point per year between 2000 and 2018, leading to a 54% electrification rate in 2018. The increase was mostly driven by new connections in rural areas as the electrification rate in urban areas decreased slightly.

According to the draft geospatial planning report published in May 2020[80], the 2018 Electrification Scoping Study[81] published by MME indicated lower connectivity rates which were estimated at 19% of rural and 71% of urban households and included connections through grid, off-grid or distributed systems. The national connectivity rate estimated in the study was 45%. The same national electrification rate is quoted in the 2018 ECB ESI Bulletin using 2017 data, with 66% of urban and 19% of rural households having electricity access. The difference between the 45% and 54% electrification rate results from different definitions used by the World Bank and MME.

Table 49 National electrification rate in Namibia

Year	Access to electricity (% of population)	Access to electricity, rural (% of rural population)	Access to electricity, urban (% of urban population)
2000	37	19	73
2001	36	19	71
2002	37	20	71
2003	38	21	71
2004	39	21	71
2005	40	22	71
2006	41	23	70
2007	44	22	78
2008	43	24	70
2009	44	21	78
2010	44	26	71
2011	42	22	70
2012	46	27	71
2013	47	27	72
2014	49	29	71
2015	52	31	75

79 https://data.worldbank.org/indicator/EG.ELC.ACCS.ZS
80 Namibia: Geospatial Least Cost Electrification Plan. Interim report prepared by IED for the MME and published in May 2020.
81 Upscaling Namibia's Electrification Efforts: From situational assessment to implementation plan," August 2018

Year	Access to electricity (% of population)	Access to electricity, rural (% of rural population)	Access to electricity, urban (% of urban population)
2016	50	32	69
2017	53	34	72
2018	54	36	72

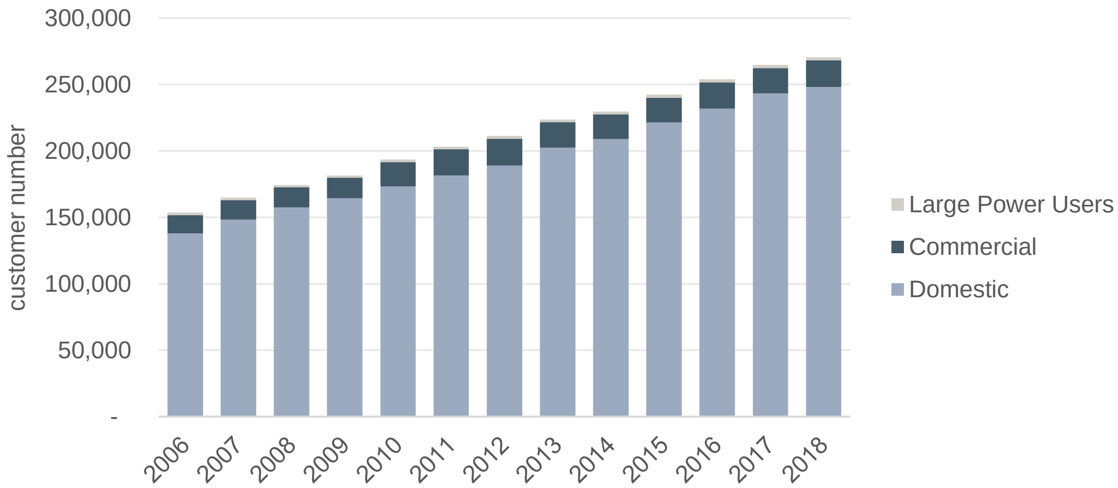
Source: World Bank

According to the geospatial electrification study, 36% of households covered by the 2018 settlement data have access to electricity that would meet the MME definition for connectivity. These figures are lower than the previous estimates as they exclude connections that do not meet the minimum standards of service specified by MME.

A2.2.3 Customer numbers and residential load

According to the ESI Bulletin, the total number of customers across all distribution companies was 270,523 in 2018. Domestic customers accounted for 92% of the total, followed by commercial customers (7%) and large power users (1%).

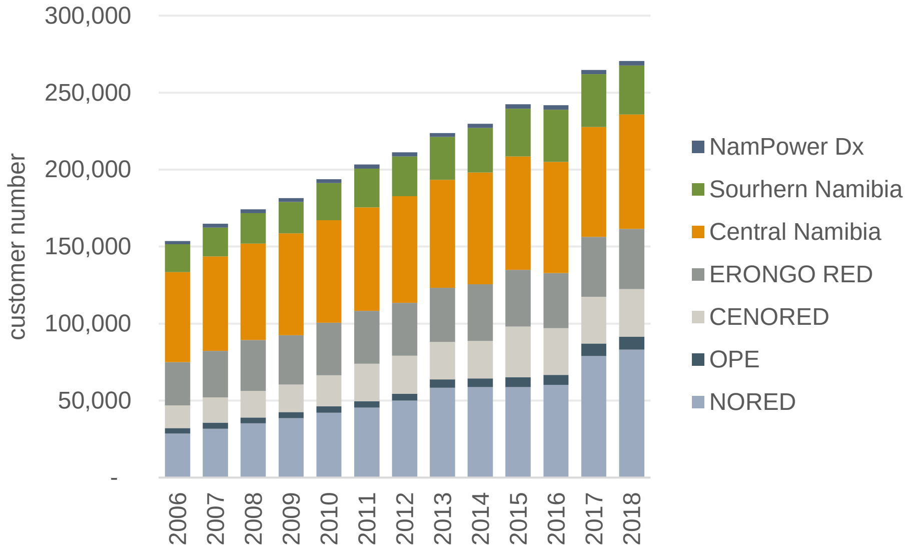
Figure 37 Evolution of customer numbers between 2006 and 2018



Source: 2018 ECB ESI Bulletin

Figure 38 shows a split of customer numbers by licensee. NORED and the Central Namibia electricity distributor together account for over 50% of the total number of customers. NORED has been systematically increasing its market share, which increased from 19% of all customers in 2006 to 31% in 2018. The Central Namibia electricity distributor decreased the share of customers supplied from 38% in 2006 to 27% in 2018. The market share of other regional distribution companies remained more stable.

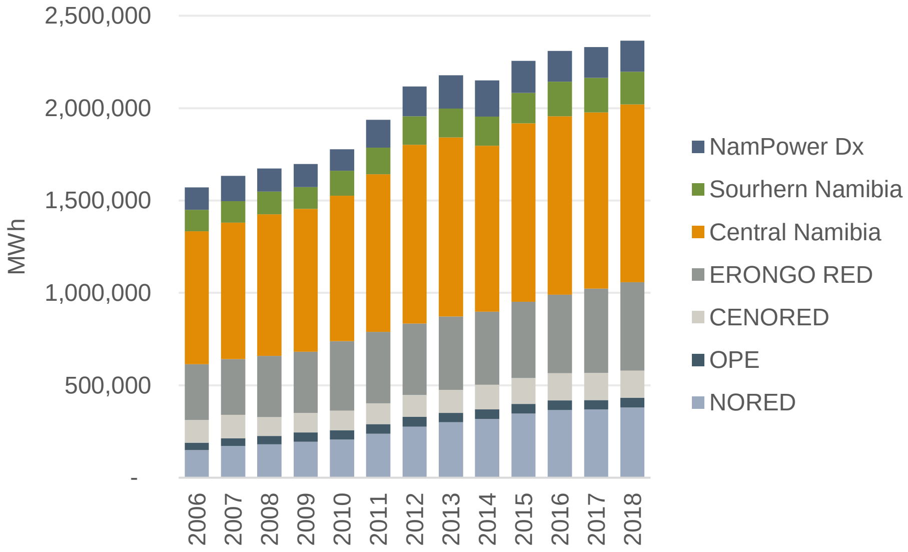
Figure 38 Customer numbers by licensee



Source: 2018 ECB ESI Bulletin

Figure 39 shows a summary of electricity sales split by licensee. Sales in the Central Namibia region is the largest contributor to total sales, although its market share has been decreasing (from 46% of total power sales in 2006 to 41% in 2018). Customers of the Erongo electricity distribution company are the second largest group in terms of power sold, accounting for 19% of the market share on average.

Figure 39 MWh sales by licensee

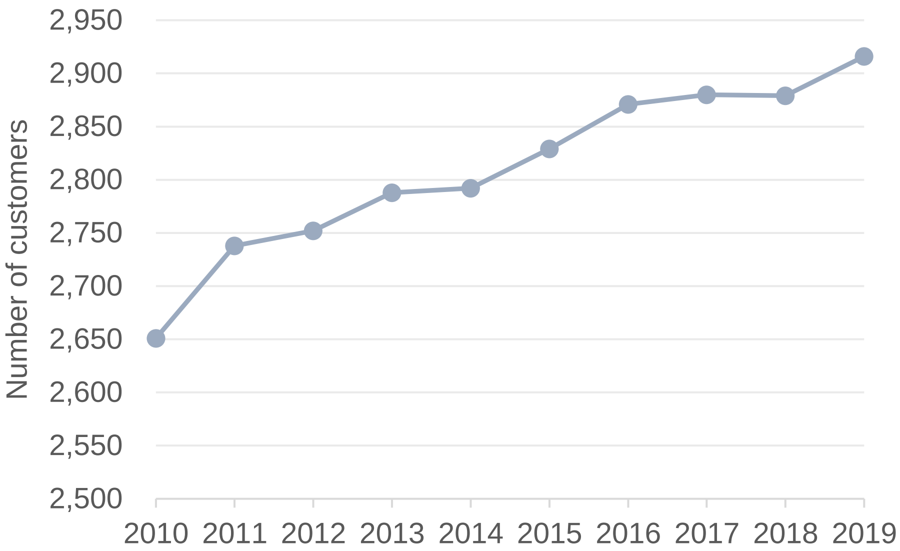


Source: 2018 ECB ESI Bulletin

NamPower is the national generation and transmission utility and the supplier of last resort. In 2019, NamPower had 2,916 electricity customers, up from 2,879 in 2018 as shown in Figure

40 below. The 2019 figure includes 58 individual transmission customers, which comprise mines, import and export arrangements, distribution companies, water pumping schemes, refineries, industrial companies and IPPs.

Figure 40 NamPower's electricity customer numbers



Source: NamPower's 2019 Annual Report

NamPower's annual reports provide a high-level sales split of electricity sector customers in Namibia, as shown in Table 50 below. Namibian customers[82] accounted for the majority of sales in 2019 (84%), followed by the Skorpion Zinc Mine (approximately 10% of units sold in 2019). Exports accounted for roughly 3% of power sold in 2019.

There are inconsistencies between energy sales as reported in NamPower's annual reports in Table 50 compared to data provided by NamPower directly in response to the data request in Table 48, however the differences are small and not material to subsequent analysis.

Table 50 Units sold into the system by customer type (GWh, 2019)

Customer	2015	2016	2017	2018	2019
Customers in Namibia	3,169	3,324	3,454	3,585	3,503
Skorpion Zinc Mine	474	440	471	444	409
Orange River	139	145	132	142	128

[82] Includes NamPower's sales to distribution companies and direct suppliers, such as mines and water pumping schemes.

Customer	2015	2016	2017	2018	2019
Exports	88	99	100	114	119
Total	3,870	4,008	4,157	4,285	4,159

Source: NamPower Annual Report 2019

A2.2.4 Industrial consumers

The industrial sector is dominated by mining activity. Some of the large customers include zinc (Skorpion), uranium (Rössing, Swakop-Husab), copper (Tschudi), Orange River and Whale Rock Cement plant. In the case of Skorpion Zinc Mine, Eskom supplies the power to NamPower's network which then supplies the mine.

Since the acquisition of the Skorpion Zinc Mine by Vedanta Zinc International (VZI), the life of the mine has been extended three times from 2015 to 2020. At the beginning of 2020, the mine went into an extended shutdown for four months to carry out essential maintenance work because of pit failures[83]. In March 2020, VZI indicated that further studies were needed to explore whether the remaining ore can be extracted using safer mining methods.

A2.2.5 Net metering

In 2015, ECB introduced net metering rules for the distribution companies to allow domestic generation from customers with rooftop solar PV installations. The net metering scheme was designed to reduce investment needs of licensees and IPPs and to allow customers to generate power for their own consumption. Additionally, the programme is meant to promote sustainable RES and to contribute towards reduction in the unemployment rate[84]. During the stakeholder consultation phase, ECB indicated that currently 52 MW of capacity is operating under the net metering scheme. This capacity is spread across the NamPower and REDs customer base.

The net metering scheme is subject to generation capacity limits where any net metering installation must not exceed the lower of the main electricity supply circuit breaker current rating (converted to kVA) and 500 kVA. Additional restrictions on the number of aggregate installations can also be placed by distributors. It is understood that these requirements were introduced due to limitations of distributors' grids and their ability to absorb variable RES and maintaining stability standards.

Currently, net metering installations are exempt from the licensing requirement. The compensation rates for excess energy fed into the grid is developed according to the avoided cost methodology which must be submitted to the ECB for approval.

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83 https://www.vedanta-zincinternational.com/news-and-media/announcements/2019/167-vzi-clarifies-status-of-skorpion-zinc-operations-in-namibia

[84] ECB, Net metering rules published in the Government Gazette on 15 November 2016. https://www.ecb.org.na/images/docs/Economic_Regulation/NET_METERING-Final%20Rules.pdf

A2.2.6 Demand-side management

Demand-side management (DSM) comprises measures undertaken on the consumer side to reduce energy consumption. Most common solutions include energy efficiency measures, energy demand shifting and reduction. Demand-side measures help more effectively match demand and supply in the electricity system and overcome network constraints.

ECB completed two DSM studies for Namibia in 2006 and 2016. The first study examined the suitability of different DSM options and provided a shortlist of DSM tools that should be examined in more detail. The 2016 update report provided a review of progress with regard to previous work. NamPower's website[85] indicates that the following DSM tools were either implemented or under consideration:

- Replacement of incandescent bulbs with Light Emitting Diode (LED) light bulbs

  The 1 million LED Campaign was launched by NamPower in August 2016 as part of the Short-Term Critical Supply Programme (STCS). Phase I of the programme was completed in June 2017. The audit process conducted between January 2017 and May 2017 confirmed 181,955 LED bulbs had been installed which translated into a 8 MW reduction in demand at the time[86].

- Installation of 20,000 Solar Water Heaters (SWH)

  Under this programme, NamPower aimed to incentivise the installation or replacement of 20,000 electric water heaters with solar water heaters. The programme has not yet been implemented but was expected to reduce the peak demand by about 10 MW.

- Virtual Power Station (VPS) and Demand Reduction (DR) programme

  The purpose of the programme was to avoid or mitigate uncontrolled load shedding during emergencies, or when Namibia's import suppliers reduce their supplies to Namibia on short notice or unexpected. This programme was aimed at electricity users with own standby generators and large industrial customers that could partially reduce their loads for a short period. Under the scheme, NamPower can request those customers to either support the system with additional generation or reduce the load as part of a load shedding mitigation process. In return, NamPower would offer favourable electricity rates in line with respective contracts to the customers providing additional generation to the system. The customers participating in the DR programme would receive consideration in any load shedding event. The resulting maximum reduction in demand was estimated at around 70 MW. Agreements were signed with some customers, and others were investigated to determine the grid synchronising requirements. As the load shedding crises passed, the programme was not pursued further. The contribution from this programme is only a mitigation measure against load shedding and cannot be considered in a load forecast.

[85] https://www.nampower.com.na/Page.aspx?p=168
[86] NamPower Annual Report 2018

Additionally, the following measures were identified as viable options in the 2016 DSM study:

- Consumer awareness - the 2016 ECB DSM study envisaged a targeted consumer awareness campaign undertaken in parallel with other DSM initiatives. This was also the case with the 2006 DSM study, but the campaign was not implemented due to insufficient resources and organisational hurdles. The new approach suggested in the 2016 study includes identification of a DSM champion, an entity that would lead the overall communication strategy and an action plan. This is not a measure that can be modelled in the NIRP.

- Tariff measures - the existing tariff framework includes TOU charges for customers with appropriate meters. Additional measures suggested in the 2016 DSM study include wider roll out of smart meters capable of remote reduction of the current limit and implementation of lower current limiters. Changes to tariff structure are primarily targeted at domestic customers who are the main contributors to the evening demand peak in Namibia. The introduction of changes to tariff designs has not been specifically modelled in the NIRP.

- Water heater load control - according to the 2016 DSM study, in 2015 there were approximately 40,000 ripple receivers in operation in Windhoek and Walvis Bay. It is not clear more have been installed in the last five years. The objective of ripple control is to reduce the peak evening demand and re-activate water heaters at the start of the off-peak period. Additional ripple control on electric water heaters would be an alternative to solar hot water heating.

- Battery storage - integration of small scale customer generation and energy storage was identified as one of the new DSM measures proposed in the 2016 study. The price of batteries has so far prevented implementation of this initiative, but the financial viability could change in the future as technology prices evolve over time.

A2.2.7 Impact of Covid-19 pandemic on the Namibian economy

Electricity consumption is closely linked with GDP.

In April 2020, the Central Bank of Namibia published a Financial Stability report which estimates that real GDP in Namibia will contract by 6.9% in 2020 due to the Covid-19 pandemic. This is in contrast to the early 2020 forecasts which predicted annual GDP growth of 1.5% and 1.4% in 2020 and 2021 respectively. The severity and duration of the downturn remain uncertain and are difficult to estimate. The Central Bank of Namibia estimates that the economy will partially recover in 2021 with a positive real GDP growth of 1.8%. It is worth noting that at the time of writing this report, countries in SSA have not experienced the impact of the pandemic to the same extent as other countries, such as the US, Brazil, Italy, Spain and the UK. Nevertheless, the spill over of the global economic slowdown are expected to negatively impact the domestic economy through both business activities as well as a decline in the number of tourists visiting SSA. In particular, the risks to the Namibian economy include international and domestic lockdowns, restrictions on movement and business activity as well as low commodity prices. Sudden and unpredictable exchange rate movements add to the uncertainty of future economic outlook. The Rand (to which Namibian dollar is pegged) has been gradually increasing in value following an initial strong depreciation. The current exchange rate is roughly at the same level as pre-pandemic (1 US$ = 14.8 ZAR; in April 2020 the value was 1 US$ = 19 ZAR).

The World Bank forecast estimates a less negative impact of Covid on the Namibian economy. As shown in the table below, real GDP is forecast to contract by 4.8% in 2020 and rebound by 3% in 2021. The South African economy is expected to experience a more severe contraction of 7.1% with a similar recovery rate in the next year.

Table 51 Sub-Saharan Africa country forecasts (real GDP growth)

Country	2019	2020	2021
Namibia	-1.1%	-4.8%	3.0%
South Africa	0.2%	-7.1%	2.9%
Angola	-0.9%	-4.0%	3.1%
Botswana	3.5%	-9.1%	4.2%
Zambia	1.7%	-0.8%	2.4%
Zimbabwe	-8.1%	-10.0%	2.9%

Source: World Bank

To mitigate negative impacts of the coronavirus on the economy, the Government of Namibia announced a stimulus package of N$ 8.1 billion which includes close to N$ 6 billion of direct support to affected businesses and households. Furthermore, to reduce the cost of borrowing, the Central Bank of Namibia reduced the repurchase agreement (repo) rates by 200 basis points since March 2020. Additional recession relief measures, such as mortgage holidays and amendment of borrower limits were also introduced.

The Central Bank of Namibia has published a risk matrix, which aims to provide an assessment framework that helps with the analysis of the impact of Covid-19 pandemic. Extracts of the matrix are provided below.

Table 52 Impact of Covid-19 risk matrix

Risk category	Direction of risk	Probability of risk
Global economic slowdown	Increase	High
Domestic economic slowdown	Increase	High
Namibia sovereign credit rating downgrade	Increase	High
South Africa sovereign credit rating downgrade	Increase	High
N$/ZAR depreciation	Increase	Medium
Increase in household debt	Increase	High
Increase in corporate debt	Increase	High

Source: Financial Stability report published by the Central Bank of Namibia

In addition to the negative impact that Covid-19 has already had on the Namibian economy, the Central Bank's analysis shows a significant increase in the probability of negative economic events occurring in the future. These include the risk of global and domestic recession, national and regional credit rating downgrade resulting in higher borrowing costs and an increase in corporate and household debt.

A2.3 2016 NIRP Demand Forecast

A demand forecast was prepared as part of the 2016 NIRP under three scenarios: reference, low and high and covers the period from 2014 to 2035. The forecast was for the electricity sales and supply for all of Namibia (no differentiation between the power supplied by or through NamPower and electricity in the MSB market which, at that date, had not been implemented).

A2.3.1 Reference case

The forecast for the reference case is shown in the table below. For peak demand, the forecast estimated an increase from 646 MW in 2016 to 1,329 MW in 2035 which in percentage terms translates to an annual growth rate of 3.9%. In terms of energy generated, the forecast predicted an increase from 4,241 GWh in 2016 to 8,490 GWh in 2035 with an average annual growth rate of 3.7%.

Table 53 2016 NIRP demand forecast - reference case

Year	Sales (GWh)	Generated energy (GWh)	Peak demand (MW)
2014	3,184	3,654	554
2015	3,402	3,871	597
2016	3,728	4,241	646
2017	3,998	4,549	693
2018	4,201	4,780	733
2019	4,333	4,930	758
2020	4,483	5,100	786
2021	4,647	5,288	816
2022	4,784	5,443	842
2023	4,927	5,606	869
2024	5,091	5,793	899
2025	5,265	5,991	931
2030	6,281	7,147	1,119
2035	7,461	8,490	1,329
2015-2035	4.0%	4.0%	4.1%

Source: 2016 NIRP

The demand forecast used in the 2016 NIRP study combined the use of regression analysis for organic growth and added step loads for large industrial users. Sales data from NamPower's annual reports were converted into calendar years and regressed on GDP, average electricity price (both expressed in constant terms) and population indicators. Regression analysis showed no statistically significant relationship between energy sales and electricity price data and between energy sales and population indicators. In addition, the relationship between energy sales and electricity price was of the wrong sign, suggesting no sensible economic meaning should be attached to the coefficient. The resulting regression equation was of the form:

$$\text{Sales (GWh)} = 551.77 + 0.0386 * \text{GDP (N\$ millions)}$$

With sales and GDP expressed on a calendar year basis and transformed into logs. The coefficient on the explanatory variable suggests that a 1% increase in GDP leads to a 0.03% increase in power sales which appears unrealistically low. Economic theory suggests that economic activity and power sales should be closely correlated and therefore the elasticity between power sales and GDP close to zero is unlikely.

A2.3.2 Step loads

In order to identify significant new loads, interviews were conducted with NamPower, distribution companies and several large customers. Step loads were categorised with regard to economic activity (mining, water pumping, commercial/industrial) and probability of materialising (high, medium and low).

Table 54 Step loads considered in 2016 NIRP

Scenario	Load name	Prob	Load (MW)	Load factor	Start Year	Last Year
			Mining loads			
All	Husab Mine (Years 2017-2023)	H	44.10	0.75	2017	2023
All	Husab Mine (Years 2024-2031)	H	44.10	0.75	2024	2031
All	Husab Mine (Years 2032-2036)	H	44.10	0.75	2032	2036
All	Namibia Custom Smelter (NCS)	H	25	0.75	2016	2099
All	Navachab	H	8.50	0.75	2016	2099
Ref High	Calueque Dam	M	4.50	0.75	2017	2099
Ref High	Lofdal Mine	M	3.50	0.75	2019	2099
High	B2 Gold	L	14.00	0.75	2019	2099
High	Congo Africa (Kombat Copper)	L	7.20	0.75	2017	2099
High	Gergarub Mine	L	19.00	0.75	2018	2099

Scenario	Load name	Prob	Load (MW)	Load factor	Start Year	Last Year
High	Lodestone Namibia (Dordabis)	L	14.40	0.75	2019	2099
High	Mertens Mining	L	4.50	0.75	2018	2099
High	Okanjande Graphite Mine	L	2.85	0.75	2018	2099
High	Omitiomire	L	3.80	0.75	2018	2099
High	Zhonge Resources	L	9.50	0.75	2020	2099
	Water pumping loads					
All	Erongo Desalination Company (EDC)	H	2.70	0.60	2016	2099
All	Aussenkehr Upgrade	H	3.17	0.60	2016	2099
All	NamWater Swakop South (for Husab)	H	2.85	0.60	2016	2099
	Commercial/Industrial loads					
All	Lady Pohamba Private Hospital	H	1.97	0.60	2016	2099
All	Karasburg upgrade	H	0.90	0.60	2017	2099
All	Brakwater development	H	3.60	0.60	2016	2099
All	Cuito Upgrade	H	5.40	0.60	2018	2099
All	Erongo Red NamPort (Port Extension)	H	13.00	0.60	2017	2099
Ref High	Cuando Cubango	M	5.10	0.60	2018	2099
Ref High	Okombahe Upgrade	M	0.95	0.60	2018	2099
Ref High	Ruby Upgrade	M	3.80	0.60	2016	2099
All	Otavi Rebar	L	31.50	0.60	2018	2099
Ref	Mass Housing Program – Years 2016-2020	M	67.5	0.20	2016	2020
Ref	Mass Housing Program – Years 2021-2025	M	67.5	0.20	2021	2025
Ref	Mass Housing Program – Years 2026-2099	M	67.5	0.20	2026	2099
Low	Mass Housing Program – Years 2016-2020	L	33.8	0.20	2016	2020
Low	Mass Housing Program – Years 2021-2025	L	33.8	0.20	2021	2025
Low	Mass Housing Program – Years 2026-2099	L	33.8	0.20	2026	2099

Scenario	Load name	Prob	Load (MW)	Load factor	Start Year	Last Year
High	Mass Housing Program – Years 2016-2020	L	146.3	0.20	2016	2020
High	Mass Housing Program – Years 2021-2025	L	146.3	0.20	2021	2025
High	Mass Housing Program – Years 2026-2099	L	146.3	0.20	2026	2099

Source: 2016 NIRP

The 2016 NIRP demand forecast also considered demand-side measures and renewable energy programmes. These included LED light bulbs, solar thermal heaters and behind-the-meter installations of solar PV panels (see Section A2.2.6).

The breakdown of energy demand forecast for the reference scenario is available in the table below.

Table 55 Reference forecast energy components (GWh)

Year	Sales (organic)	Sales (step)	DSM reduction	Sales (total)	Transmission losses	Generation (total)
2014	3,184	0	0	3,184	470	3,654
2015	3,402	0	0	3,402	469	3,871
2016	3,552	200	-24	3,728	514	4,241
2017	3,697	352	-51	3,998	551	4,549
2018	3,832	448	-78	4,201	579	4,780
2019	3,973	466	-106	4,333	597	4,930
2020	4,119	496	-133	4,483	618	5,100
2021	4,273	535	-160	4,647	640	5,288
2022	4,433	539	-188	4,784	659	5,443
2023	4,600	543	-215	4,927	679	5,606
2024	4,774	560	-243	5,091	702	5,793
2025	4,956	579	-270	5,265	725	5,991
2030	5,994	605	-318	6,281	865	7,147
2035	7,280	542	-361	7,461	1,028	8,490

Source: 2016 NIRP

A2.3.3 Comparison of the NIRP forecast and actual demand data

Table 56 compares the NIRP forecast with actual data recorded over period 2016-2018 (and 2019 for peak demand). The forecast turned out to predict future outcomes reasonably well, which was unexpected given the economic slowdown that Namibia experienced in recent years and the fact that some of the material loads did not materialise. With regard to energy, the forecast predicted consistently lower figures than actual outcomes. The predictions for peak demand are somewhat puzzling, as in the first two years the forecast predicted lower peak demand than the outturn, but in 2018 that relationship between the forecast and actual figures was reversed with the forecast indicating faster growth of peak demand than the outturn. The table suggests that the system load factor in 2018 is particularly high at 82% suggesting a potential problem with the data (we cannot suggest another explanation).

Table 56 Comparison of the NIRP forecast and actual data

Peak demand (MW)			
Year	**Forecast (load factor in brackets)**	**Actual** (load factor in brackets)	**Difference (forecast – actual)**
2016	646 (74.9%)	677 (76.0%)	-31 (-5%)
2017	693 (74.9%)	695 (75.7%)	-2 (+0%)
2018	733 (74.4%)	672 (82.0%)	61 (+9%)
2019	758	720	38 (+5%)
Energy demand- generated energy (GWh)			
Year	**Forecast**	**Actual**	**Difference (forecast – actual)**
2016	4,241	4,506	-265 (-6%)
2017	4,549	4,610	-61 (-1%)
2018	4,780	4,826	-46 (-1%)
Energy demand- sales (GWh)			
Year	**Forecast**	**Actual**	**Difference (forecast – actual)**
2016	3,728	4,008	-280 (-7%)
2017	3,998	4,157	-159 (-4%)
2018	4,201	4,285	-84 (-2%)

Source: Combined information from tables 2,8 and 13

A2.4 Review of NamPower's 2020 peak demand forecast

The Transmission Maximum Demand Load Forecast (Demand forecast data 2020.xlsx) shared by NamPower is a peak demand forecast of the load that is carried by the transmission network and covers the period between 2020 and 2044. NamPower has also provided ECA with a high-level description of methodology which is available in a word document Demand Forecast Methodology.docx (summarised in Section A2.4.2 below). This was further discussed in a virtual meeting with NamPower.

The peak demand forecast is updated on an annual basis and considers four scenarios: low, medium, high probability and base case high probability which refer to the probability of step loads materialising. The estimated values are inclusive of the Skorpion Zinc Mine and are calculated for the Namibian load only, except for Ondjiva, Ghanzi and Rietfontein which are estimated to contribute 9.6 MW, 5 MW and 1.4 MW to the demand forecast respectively[87]. The peak demand additionally excludes Orange River consumption which refers to supply points connected to Eskom's network.[88] The resulting demand forecast under the four different scenarios is presented in Table 57 and Figure 41.

A2.4.1 Peak demand forecast

For the base case scenario, the AAG equals 1.07% between 2020 and 2044. The largest drop in peak demand is expected in 2020 with a forecast decline of 7% due to modernisation of the Skorpion Zinc Mine. The closure of the Skorpion mine has resulted in a reduction of forecast demand from 78 MW to 2.4 MW in March 2020. According to the information supplied by NamPower, the refinery at the mine might reopen in March 2022. Electricity consumption is not expected to recover for another five years and is only expected to exceed the 2019 values in 2027. No significant impact on peak demand is expected to result from the Covid-19 pandemic[89] or the MSB framework.

Table 57 NamPower forecast of peak load (MW)

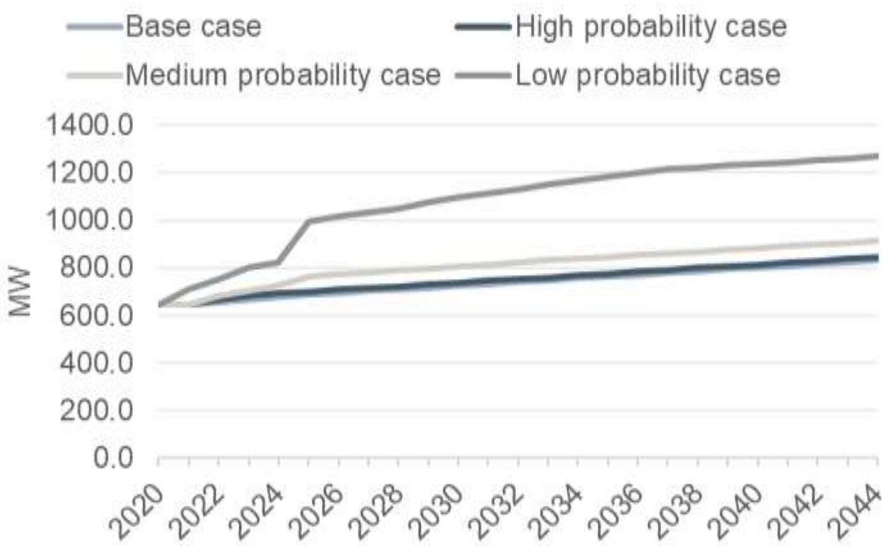
Year	Base-load	Forecast including step loads		
		High probability	Medium probability	Low probability
2020	644	644	644	644
2021	647	647	647	708
2022	657	669	682	752
2023	668	681	704	801
2024	679	692	728	824

[87] As per the clarification email received on the 25th of August 2020
[88] As per the clarification email received on the 10th of December 2020
[89] The impact of the coronavirus was discussed during the virtual meeting with NamPower on the 7th of September.

Year	Base-load	Forecast including step loads		
		High probability	Medium probability	Low probability
2025	687	699	764	998
2026	695	707	772	1016
2027	702	715	781	1034
2028	710	723	789	1051
2029	718	731	798	1074
2030	726	738	806	1097
2031	733	746	815	1114
2032	741	754	823	1132
2033	748	761	831	1149
2034	756	769	839	1166
2035	764	776	846	1182
2036	771	784	854	1199
2037	779	792	861	1215
2038	786	799	868	1223
2039	794	807	876	1230
2040	802	814	883	1238
2041	809	822	891	1245
2042	817	829	898	1252
2043	824	837	905	1260
2044	832	845	913	1267
AAG	1.07%	1.13%	1.46%	2.86%

Source: NamPower

Figure 41 Forecast peak load



Source: NamPower

A2.4.2 NamPower's methodology for the 2020 forecast

The high-level methodology used by NamPower to derive the peak demand forecast is developed for transmission planning purposes and is based on trend analysis of historical meter data (diversified and adjusted for seasonality) and step loads for recent years.

A simple linear trend is then used to forecast the peak demand at a large number of points on the network. Step loads are then added to account for events not associated with organic/trend growth. The loads are then aggregated and diversity factors applied to give loads at higher voltage points on the network and these, in turn, are aggregated to give the maximum demand on the whole power system.

The process for adding step loads is aligned with NamPower's Customer Connection Policy. Applicants are classified as low, medium or high probability in accordance with the following rules:

- Low Probability- Applicants who had not accepted NamPower's connection offer within the past 12 months and applicants who are at the initial stage of connection process (held an informal meeting with NamPower)

- Medium Probability- Applicants who received an offer to connect within the last 12 months and prospective customers who submitted and paid for a formal load application

- High Probability- Applicants who accepted the offer, signed the Power Supply Agreement (PSA) and made the first payment. All steps need to be completed within 12 months of receiving an offer to connect

Customers are removed from prospective step load additions if they have not accepted their connection offer for the past 24 months.

Step load information listed below has been provided by NamPower and is correct as of the 3rd of August 2020. The Namibian mining sector relies on the resources of uranium, Copper, Zinc and Gold. The probability of the mining step loads materialising will therefore depend on global prices of those metals. Water pumps include desalination plants and water pumps related to mine operations. Finally, the commercial and industrial sector is a broad category that includes port expansions, housing programmes and electrification programmes. Table 58 provides summary step load information under various scenarios. A more detailed break down is available in the annex.

The base case high probability scenario includes step load additions from existing and new customers. The highest increase is attributed to growing demand from mines and residential, commercial, and industrial loads, resulting in an additional 11.3 MW of power demanded by 2025. Other scenarios (high, medium and low) include step loads which are less likely to materialise and which would increase peak demand by 13.3, 68.3 and 248.3 MW respectively. The Skorpion mine and the Coastal Central Water Carrier individually are estimated to increase peak demand by 94.1 and 140 MW respectively, although the probability of these projects materialising is low.

Table 58 Summary of step load data under different scenarios (MW)

Scenario	2021	2022	2023	2024	2025
Base case high probability	7.8	10.3	14.3	17.8	18.0
High probability	-	12.6	13.3	13.3	13.3
Medium probability	0.1	14.2	15.0	27.4	56.4
Low probability	65.8	75.6	103.8	103.8	248.3

Source: NamPower response to information request received 06/08/2020

A2.4.3 The electrification access programme and its impact on peak demand forecast

The methodology document provided by NamPower does not state whether an allowance for additional connections, resulting from the electrification access programme, has been made. Based on the results of the interim geospatial least cost plan report[90], it is assumed that new connections will contribute 90 MW in demand by 2030, which is equivalent to a 9 MW demand increase per year. The adjusted peak demand forecast is presented in Table 59.

[90] Namibia: Geospatial Least Cost Electrification Plan. Interim report prepared by IED for the MME and published in May 2020.

Table 59 NamPower forecast of peak load (MW) after accounting for the impact of electrification programme

Year	Base-load	Forecast including step loads		
		High probability	Medium probability	Low probability
2020	644	644	644	644
2021	656	656	656	717
2022	675	687	700	770
2023	695	708	731	828
2024	715	728	764	860
2025	732	744	809	1043
2026	749	761	826	1070
2027	765	778	844	1097
2028	782	795	861	1123
2029	799	812	879	1155
2030	816	828	896	1187
2031	823	836	905	1204
2032	831	844	913	1222
2033	838	851	921	1239
2034	846	859	929	1256
2035	854	866	936	1272
2036	861	874	944	1289
2037	869	882	951	1305
2038	876	889	958	1313
2039	884	897	966	1320
2040	892	904	973	1328
2041	899	912	981	1335
2042	907	919	988	1342
2043	914	927	995	1350
2044	922	935	1003	1357
AAG	1.50%	1.56%	1.86%	3.15%

Source: NamPower, ECA

A2.5 Review of the national 2020 load forecast (GWh)

A2.5.1 Load forecast (GWh)

In response to the data request, NamPower provided ECA with an excel spreadsheet energy forecast 2020.xlsx containing the energy forecast for years 2021-2050. The energy forecast is a forecast of national load excluding behind-the-meter generation (rooftop solar and other self-generation that reduces the amount of electricity taken from the national grid). This is consistent with the peak demand forecast described above. One significant difference between the two forecasts is that the energy demand forecast is expressed on a financial year basis while the peak demand forecast is calculated on calendar year basis.

The time series was updated in 2020 to reflect the impact of the coronavirus pandemic. All values in the excel spreadsheet are hardcoded and have no links to underlying data or assumptions.

The forecast is developed under four scenarios: low, medium, high and base case high probability which is also consistent with the methodology of the peak demand forecast.

The base case scenario for the national load forecast (Table 60) predicts an annual average energy load growth of 1.23%. The figures include losses[91] and are calculated as the total GWh that must be injected into the system to satisfy the load of all Namibia. The forecast predicts slower energy demand growth in 2022 (increase of just 0.5%) which then grows to 2.1% in 2024. From 2025 onwards, the growth rate decreases again to around 1.5%. The base, high and medium probability forecasts provide very similar predictions. The low probability forecast stands out with higher expected energy growth (the average annual growth rate is 2%).

Table 60 Forecast national load forecast (GWh, 2021-2049)

Year	Base case	High probability	Medium probability	Low probability
2021	3,974	3,960	3,960	3,971
2022	3,992	4,026	4,038	4,106
2023	4,045	4,102	4,156	4,376
2024	4,130	4,178	4,274	4,483
2025	4,191	4,239	4,402	4,725
2026	4,242	4,292	4,517	5,286
2027	4,294	4,344	4,571	5,370
2028	4,358	4,409	4,639	5,454
2029	4,398	4,449	4,681	5,558
2030	4,451	4,502	4,737	5,640
2031	4,506	4,557	4,794	5,745

[91] Technical losses estimated at 9.7%. No information was provided on non-technical losses.

Year	Base case	High probability	Medium probability	Low probability
2032	4,574	4,626	4,866	5,832
2033	4,616	4,668	4,910	5,939
2034	4,672	4,723	4,966	6,006
2035	4,728	4,780	5,022	6,091
2036	4,799	4,851	5,093	6,177
2037	4,844	4,896	5,137	6,286
2038	4,904	4,956	5,196	6,339
2039	4,964	5,015	5,255	6,398
2040	5,037	5,089	5,329	6,457
2041	5,083	5,135	5,373	6,538
2042	5,147	5,198	5,436	6,579
2043	5,210	5,261	5,499	6,641
2044	5,289	5,340	5,578	6,705
2045	5,337	5,388	5,625	6,790
2046	5,403	5,454	5,691	6,835
2047	5,469	5,520	5,757	6,900
2048	5,551	5,603	5,840	6,966
2049	5,602	5,653	5,890	7,033
2050	5,671	5,723	5,959	7,103
AAG	1.23%	1.28%	1.42%	2.03%

Source: NamPower; information provided 09/12/2020

A2.5.2 Methodology

The high-level methodology used to develop forecast energy demand is described in a pdf document Energy Forecast_July_2020 to NIRP.pdf provided by NamPower on 14/09/2020.

The forecast relies on economic data and historical trend analysis to account for organic growth and adds step loads to reflect increases in demand from larger customers. Step load categories are as described above, i.e. the forecast distinguishes among the mining load, water pumping and towns, commercial and industrial load. Step load data is sourced from the approved transmission peak demand forecast and categorised according to the likelihood of materialising.

Due to the uncertainty related to the impact of Covid-19, economic growth was measured using last year's data. The energy load growth rates applied to different time categories until 2022 are as per Table 61.

Table 61 Growth rates assumptions until 2022

Period	Description	Assumed growth rate for 2019/2020
Morning peak	Morning peak hours as per SAPP TOU: - 5 am-10 am for low and high demand season	-0.8%
Daylight hours	Defined as: - 10 am – 18 am for low demand season - 10 am – 17 am for high demand season	-0.5%
Evening peak	Defined as: - 7 pm – 10 pm for low demand season - 6 pm – 10 pm for high demand season	0.3%
Night Hours	Defined as: - 11 pm – 5am for low and high demand season	-0.5%

Source: NamPower; information provided in response to data request on 14/09/2020

Between 2023 and 2024, the load forecast is calculated based on historical trend analysis of energy demand. Beyond 2025, future load demand is linked to the GDP growth assumed to be 1.8% between 2025 and 2030. Beyond 2030, historical GDP growth rates were sourced from the Namibia Statistics Agency (NSA) are used.

A2.5.3 The electrification access programme and its impact on the national energy forecast

New customers are assumed to contribute an additional 418 GWh in energy demand by 2030[92]. The resulting forecast, assuming a 41.8 GWh demand increase every year between 2021 and 2030, is presented in Table 62.

Table 62 Forecast national load forecast after accounting for the impact of the electricity access programme (GWh, 2021-2049)

Year	Base case	High probability	Medium probability	Low probability
2021	4,016	4,002	4,002	4,013

[92] The NamPower document describing their methodology used to derive the energy forecast does not explicitly state that the impact of the programme was considered when preparing the forecast and we have assumed that it did not.

Year	Base case	High probability	Medium probability	Low probability
2022	4,076	4,110	4,122	4,190
2023	4,170	4,228	4,281	4,502
2024	4,297	4,345	4,441	4,650
2025	4,400	4,448	4,611	4,934
2026	4,493	4,543	4,767	5,536
2027	4,587	4,637	4,864	5,662
2028	4,693	4,743	4,973	5,788
2029	4,774	4,825	5,057	5,934
2030	4,869	4,920	5,155	6,058
2031	4,924	4,975	5,212	6,163
2032	4,992	5,044	5,284	6,250
2033	5,034	5,086	5,328	6,357
2034	5,090	5,141	5,384	6,424
2035	5,146	5,198	5,440	6,509
2036	5,217	5,269	5,511	6,595
2037	5,262	5,314	5,555	6,704
2038	5,322	5,374	5,614	6,757
2039	5,382	5,433	5,673	6,816
2040	5,455	5,507	5,747	6,875
2041	5,501	5,553	5,791	6,956
2042	5,565	5,616	5,854	6,997
2043	5,628	5,679	5,917	7,059
2044	5,707	5,758	5,996	7,123
2045	5,755	5,806	6,043	7,208
2046	5,821	5,872	6,109	7,253
2047	5,887	5,938	6,175	7,318
2048	5,969	6,021	6,258	7,384
2049	6,020	6,071	6,308	7,451
2050	6,089	6,141	6,377	7,521
AAG	1.45%	1.49%	1.62%	2.19%

Source: NamPower, ECA

A2.6 Benchmarking the load forecast (GWh) results

To check the plausibility of NamPower's energy load forecast, ECA estimated a regression equation of the form:

$$\text{Log(energy sales)} = a + b*\text{Log(GDP)} + d(\text{year 2014 and after})$$

Where energy sales are measured in GWh for all customers in Namibia, including exports, Orange River and Skorpion mine, and GDP is measured in constant 2010 US$. D(year 2014 and after) denotes a dummy variable which takes the value of one for years 2014-2019 and value of zero before 2014. The dummy variable was introduced to account for increased uptake of renewables, which could alter the correlation between energy sales and GDP.

The regression was estimated using an annual sample of 30 data points (1989-2019). The estimated parameters are shown in the table below.

	Coefficients	Standard Error	t Stat	P-value
Intercept	-1.7485	0.4132	-4.2320	0.00022
log.GDP	1.0594	0.0461	22.9866	2.1E-19
D(2014 and after)	-0.0776	0.0418	-2.0945	0.0454

The regression is of a double log form, meaning that the coefficient on the independent variable denotes elasticity. The resulting equation suggests that a 1% increase in GDP is associated with a 1.05% increase in energy sales, indicating that the two variables move very closely together. The probability statistics (standard error, t stat and P-value) indicate that the equation is a very good predictor of electricity sales. This regression equation was then used to forecast energy sales in the future using actual sales in 2020 as the base year for the forecast. Assumptions for GDP growth rates between 2021 and 2026 were sourced from an International Monetary Fund (IMF) dataset updated in April 2021 and are presented in the table below. Beyond 2026, GDP is assumed to grow by 1.8% per year.

Table 63 Forecast real GDP growth rate assumptions

Year	2021	2022	2023	2024	2025	2026
GDP growth rate	2.6%	3.3%	3%	2.5%	2.5%	2.5%

Source: IMF 2021

The forecast is adjusted for the impact of the electrification access programme which predicts to add further 418 GWh of demand by 2030. The load increase is assumed to be spread out evenly between 2021 and 2030, resulting in an annual addition of 41.8 GWh.

The resulting time series predicts higher energy sales than the national load forecast estimated by NamPower. Up to 2024, the NamPower forecast is based on trend analysis with no direct relationship between energy demand and GDP. Between 2024 and 2029, the NamPower forecast is based on the assumption of a GDP growth rate of 1.8% per year. The associated average growth rate of energy load is 1.3% per year, implying an elasticity of 0.7. This is significantly lower than the statistical relationship estimated in the regression above, which indicates an elasticity of 1.06. The divergence in responsiveness of demand to GDP growth translates to a 3.2% difference in energy load over a five-year period which accumulates to nearly 11% over a 15-year period.

Differences in the two forecasts are also associated with different starting points used in estimating the load. The forecast described in this section used actual sales volume of 4,352 GWh in 2020 sourced from the 2020 NamPower Annual Report. The NamPower forecast does not provide the 2020 value, but the demand forecast in 2021 is already significantly lower.

Lastly, differences in the two forecasts may be associated with different GDP assumptions. The only GDP assumptions referenced by NamPower are for the period 2024 to 2029 and it is therefore unclear what GDP growth rates were assumed beyond 2029.

Table 64 compares NamPower's and ECA's energy forecasts. Both forecasts are presented without the addition of step loads and excluding the impact of electrification programme.

Table 64 Check of the national load forecast provided by NamPower (excluding step loads and the impact of electrification programme)

Year	ECA's forecast of energy sales for Namibia (GWh)	NamPower's forecast (GWh)	Difference
2020	4,352		
2021	4,472	3,974	11.1%
2022	4,630	3,992	13.8%
2023	4,777	4,045	15.3%
2024	4,903	4,130	15.8%
2025	5,033	4,191	16.7%
2026	5,166	4,242	17.9%
2027	5,265	4,294	18.4%
2028	5,365	4,358	18.8%
2029	5,468	4,398	19.6%
2030	5,572	4,451	20.1%
2031	5,678	4,506	20.6%
2032	5,786	4,574	20.9%
2033	5,897	4,616	21.7%
2034	6,009	4,672	22.3%
2035	6,124	4,728	22.8%
2036	6,241	4,799	23.1%
2037	6,360	4,844	23.8%
2038	6,481	4,904	24.3%

Year	ECA's forecast of energy sales for Namibia (GWh)	NamPower's forecast (GWh)	Difference
2039	6,604	4,964	24.8%
2040	6,730	5,037	25.2%
AAG (2021-2040)	2.2%	1.3%	

Source: ECA, NamPower

The peak demand forecast was estimated based on the load factor resulting from the NamPower base-load forecast. The load factor was calculated excluding the impact of the electrification programme and excludes step loads.

Table 65 Peak demand forecast (excluding step loads and the electrification programme)

Year	NamPower load factor (base forecast)	ECA peak demand forecast (MW) (using NamPower load factor)	NamPower peak demand forecast (MW)	Difference
2020	70%	710	644	9.2%
2021	70%	728	647	11.1%
2022	69%	762	657	13.8%
2023	69%	789	668	15.3%
2024	69%	806	679	15.8%
2025	70%	825	687	16.7%
2026	70%	846	695	17.9%
2027	70%	861	702	18.4%
2028	70%	874	710	18.8%
2029	70%	892	718	19.6%
2030	70%	908	726	20.1%
2031	70%	924	733	20.6%
2032	70%	937	741	20.9%
2033	70%	956	748	21.7%
2034	71%	972	756	22.3%
2035	71%	989	764	22.8%
2036	71%	1,003	771	23.1%
2037	71%	1,022	779	23.8%
2038	71%	1,039	786	24.3%
2039	71%	1,056	794	24.8%
2040	72%	1,071	802	25.2%

Year	NamPower load factor (base forecast)	ECA peak demand forecast (MW) (using NamPower load factor)	NamPower peak demand forecast (MW)	Difference
AAG (2021-2040)		2.1%	1.1%	

Source: ECA, NamPower

A2.7 Loads not considered in any forecast

Some potential loads have not been reflected in the forecast due to the low probability of materialising and lack of sufficient information. These are summarised in this section and should be reviewed in the next NIRP update.

The renewable resource in Namibia is far larger than the potential domestic electricity market, so reaching a full utilisation of Namibia's renewable energy resources means either exporting electricity to other countries or turning power to "X" (PtX), to export products/commodities/services based on cheap (green) energy.

A number of these projects are in concept phase in Namibia but have not progressed to feasibility study and cannot yet be considered as sufficiently advanced to be considered as in the current NIRP. For completeness, they are noted below.

A2.7.1 Green hydro-chemicals

- There are a number of projects that have been proposed or are under discussion. One example, whose details are confidential but can be described in broad terms, is to produce green hydrogen and its derivatives, such as ammonia, that can be used in transport, industry and agriculture:

- The project would use wind and solar PV in excess of 5 GW, feeding a production facility to generate hydrogen and ammonia, predominantly for export, but also for local supply, if required.

- The proposed project could be self-sufficient, providing for and consuming its own power generation with excess power potentially fed to the Namibia (and interconnected SAPP) grids, to supply MSB customers or NamPower and/or ancillary services.

- The project could also provide power to add-on industrial developments expected as a result of the products and by-products produced (fresh water, concentrated oxygen, hydrogen, ammonia, and power).

A2.7.2 Desalination and water pumping

To provide potable water, renewable energy could be used for desalination.

The location of desalination plants along the coast will require booster pumps to a feed the water backbone for urban and industrial areas inland.

These loads are not included in the load forecast provided by NamPower and include, amongst others, the Central Coast Desalination plant and water carriage system to Windhoek. A feasibility study undertaken by engineering consultants on bringing desalinated water to the coastal and central areas commenced in FY2019 and is scheduled to be completed in FY2020.93 The Environmental Scoping Report for the project indicated that that development will require significant and continuous power during the day and night. Some of the power supply options include the construction of a new solar PV plant or similar for feeding energy into the national grid for the project during the daytime, and supply from the national grid at night-time.[94]

A2.7.3 High performance computing

Another possible load, with matching supply, would be electricity for cryptocurrency mining and blockchain technology processes. Renewable energy power plants dedicated to on-site high-density computing and energy systems provide the possibility of self-contained, distributed, scalable, and flexible projects.

While no projects are approved, at the time of this report, the Consultant is aware of at least one such project in concept phase, with the aim to use a hybrid of wind and solar power with storage. These projects are scalable, with loads/supply of 200 MW to 1 GW and upwards.

A2.7.4 Power exports to SAPP

Namibia’s connectivity and position in the interconnected SAPP provides for the establishing of power exchange options with large consumers or utilities in other countries, whereby the natural resources of Namibia can be utilised to supply electricity loads outside the borders of Namibia. The implementation of the MSB in Namibia and similar liberating regulatory changes in the region will enhance such opportunities. However, the NIRP is concerned with the investment requirements to satisfy Namibia’s electricity load and is not intended to analyse export options.

Electricity supply options located outside of Namibia can also be used to satisfy load in Namibia and is considered as part of the NIRP.

[93] Namwater Integrated Annual report 2018/2019
[94] Environmental Scoping Report: Central Coast desalination and water carriage system, SLR Consulting, 2019

A2.8 Impact of the electrification access programme

A2.8.1 Electrification access programme

The draft Geospatial Planning Interim Report[95] estimates that in order to reach universal connectivity by 2030, an additional 430,000 new household connections will need to be added by 2030. This will include customers that will be connected to the grid (through grid densification, intensification or extension) as well as those that will use off-grid solutions, such as isolated mini-grids and standalone solutions. The report assumes a 1.7% population growth between 2018 and 2030 and an average household size of 3.9.

The analysis conducted in the Geospatial Least Cost Electrification Plan indicates that approximately 95% of total required connections (414,600) lie within a reasonable distance from the main grid. These comprise:

- 77% of required connections which are located in an area that is already electrified or within 2 km of an electrified settlement. These customers could be added to the existing network and would only require a dropline or limited Low Voltage (LV) network expansion (grid densification);

- 10% of required connections which are located from 2 km to 5 km away from an existing Medium Voltage (MV) grid. These connections would require additional capital investments;

- 9% of required connections which are located from 5 km to 20 km away from an existing MV grid. These connections would require higher capital investments.

The remaining 5% (18,100) of connections required to reach universal connectivity by 2030 are located in remote areas which are unlikely to be connected to the national grid. It is envisaged that other solutions, such as mini-grids or standalone systems will be used to provide electricity to those settlements.

A2.8.2 Implied load that will be added to the grid

The total number of grid connections (414,600) was then used to conduct subsequent analysis under two scenarios, but the more realistic scenario predicts that due to the challenging timeline needed to achieve universal connectivity, only settlements which have at least 250 inhabitants and are located within 20 km of the main grid will be connected to the national grid by 2030. This results in 290,496 new connections and an estimated population of 1.1 million to be connected. The report indicates that a population of 1,000 will have a total annual consumption of 380,000 kWh, so with a population of 1.1 million this sums up to approximately 418 GWh per year (equivalent to 120 kWh per connection per month). The annual consumption figure includes assumed distribution losses of 10%.

[95] Namibia: Geospatial Least Cost Electrification Plan. Interim report prepared by IED for the MME and published in May 2020.

A2.8.3 The impact of electrification access programme on NamPower's national demand forecast

It is unclear whether the universal access electrification programme have already been reflected in the national load forecast provided by NamPower. The forecasts provided to NamPower by the REDs should have made an allowance for these loads, but no information was available on the assumptions underlying the RED forecasts or how NamPower used the RED's forecasts when forecasting their GWh load. The load of 418 GWh per year represents approximately 11% of NamPower's forecast for 2021 (and 9% in 2030). Assuming equal contributions between 2021 and 2030, this is equivalent to 41.8 GWh per year.

A2.9 Conclusion

The regression analysis presented in Section A2.6 indicates that historically electricity demand and GDP moved very closely together. The coefficient associated with the GDP variable suggests that whenever GDP increases by 1%, demand for electricity will increase by 1.06%. This relationship was used to develop a forecast of energy demand until 2040. An additional adjustment was made for the impact of the electrification access programme which is expected to contribute an additional 418 GWh by 2030. Step loads were added on top of regression analysis to account for large new demand additions. On average, energy demand is expected to grow by 2.7% per year which is slightly above the expected average annual growth rate of GDP (2.1%).

The peak demand forecast was then developed based on the energy load forecast and the load factor resulting from the NamPower demand forecast. Peak demand is forecast to increase from 710 MW in 2020 to 1,243 MW in 2040 which translates into a 2.8% annual growth rate.

The resulting energy and peak demand forecast are presented in the table below.

Table 66 Namibia's central national load forecast[96]

Year	ECA base energy forecast (GWh)	Step loads (GWh)	Electrification access programme (GWh)	Total energy forecast (GWh)	Maximum demand (MW)
2020	4,352	-	0	4,352	710
2021	4,472	-	42	4,514	737
2022	4,630	-	84	4,714	780
2023	4,777	-	125	4,902	816
2024	4,903	-	167	5,070	842
2025	5,033	-	209	5,242	870

[96] Step loads are estimated based on the methodology described in Section 5.2 and subjective assessment

Year	ECA base energy forecast (GWh)	Step loads (GWh)	Electrification access programme (GWh)	Total energy forecast (GWh)	Maximum demand (MW)
2026	5,166	-	251	5,417	900
2027	5,265	50	293	5,608	937
2028	5,365	50	334	5,749	959
2029	5,468	51	376	5,895	986
2030	5,572	51	418	6,041	1,011
2031	5,678	51	418	6,147	1,027
2032	5,786	292	418	6,496	1,109
2033	5,897	293	418	6,608	1,129
2034	6,009	294	418	6,721	1,145
2035	6,124	293	418	6,835	1,161
2036	6,241	294	418	6,953	1,175
2037	6,360	292	418	7,070	1,195
2038	6,481	292	418	7,191	1,211
2039	6,604	291	418	7,313	1,228
2040	6,730	291	418	7,439	1,243

Source: NamPower, ECA calculation

Annex: Peak demand forecast- step loads under different scenarios

Table 67 Step loads under the base case high probability scenario (MW)

Customer	2021	2022	2023	2024	2025
Existing customers total	**7.8**	**10.3**	**10.9**	**11.1**	**11.3**
Mining Loads total	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**
Elizabeth Bay	4.7	4.7	4.7	4.7	4.7
Navachab	1.2	1.2	1.2	1.2	1.2
Water Pumping Loads total	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Wlotzka	0.3	0.3	0.3	0.3	0.3
Residential, Commercial, Industrial Loads total	**1.5**	**4.0**	**4.7**	**4.9**	**5.1**
Aris Upgrade	-	0.6	1.0	1.0	1.0
Aussenkehr Upgrade (phase 2, 3 and 3)	-	1.8	1.8	1.8	1.8
Karasburg Upgrade	-	-	0.1	0.2	0.3
Ruby Upgrade	1.5	1.6	1.7	1.8	1.9
New customers total	**-**	**-**	**3.4**	**6.7**	**6.7**
Residential, Commercial, Industrial Loads total	**-**	**-**	**3.4**	**6.7**	**6.7**
Brakwater development	**-**	**-**	**3.4**	**6.7**	**6.7**

Source: NamPower response to information request received 06/08/2020

Table 68 Step loads under high, medium and low probability scenarios (MW)

Customer	2021	2022	2023	2024	2025
Total for high probability	**-**	**12.6**	**13.3**	**13.3**	**13.3**

Customer	2021	2022	2023	2024	2025
Mining loads	**-**	**12.6**	**12.6**	**12.6**	**12.6**
B2 Gold	-	12.6	12.6	12.6	12.6
Residential, commercial and industrial loads	**-**	**-**	**0.7**	**0.7**	**0.7**
Airport Upgrade	-	-	0.7	0.7	0.7
Total for medium probability	**0.1**	**14.2**	**15.0**	**27.4**	**56.4**
Mining loads	**-**	**14.0**	**15.0**	**27.4**	**56.4**
Lodestone Namibia (Dordabis)	-	-	-	2.3	14.4
Navachab	-	-	-	-	9.8
Rosh Pinah	-	-	0.9	2.1	7.5
Rubicon Lepidico Temp Supply	-	4.1	4.1	4.1	-
Rubicon Lepidico	-	-	-	-	5.7
Swakop Uranium Trolley Assist		10.0	10.0	10.0	10.0
Uis Tin Mine	-	-	-	9.0	9.0
Water pumping loads	**-**	**-**	**4.8**	**4.8**	**4.8**
RNT (Cafuma pump station)	-	-	4.8	4.8	4.8
Residential, commercial, industrial loads	**0.1**	**0.2**	**5.1**	**6.1**	**7.1**
North Port	-	-	-	1.0	2.0
Oranjemund Town Supply	-	-	4.8	4.8	4.8
Hochfeld	0.1	0.2	0.3	0.3	0.3
Total for low probability	**65.8**	**75.6**	**103.8**	**103.8**	**248.3**
Mining loads	**65.8**	**71.6**	**99.8**	**99.8**	**99.8**

Customer	2021	2022	2023	2024	2025
Langer Heinrich	-	5.7	5.7	5.7	5.7
Skorpion	65.8	65.8	94.1	94.1	94.1
Water pumping loads	**-**	**-**	**-**	**-**	**144.5**
Neckartal Dam Agricultural project	-	-	-	-	4.5
Coastal Central Water Carrier	-	-	-	-	140.0
Residential, commercial, industrial etc. Loads	**-**	**4.1**	**4.1**	**4.1**	**4.1**
Aussenkehr (phase 5)	-	-	-	-	-
Hangala Chicken	-	4.1	4.1	4.1	4.1
Tsumeb University and Hospital	-	-	-	-	-

Source: NamPower response to information request received 06/08/2020

A3 Wairoa: model description

About Wairoa

Wairoa[97] simulates electricity market outcomes under different conditions, using both enumerative and linear programming algorithms. The model is designed to maximise run speeds and user-friendliness, reflected in its primarily Excel-based nature, which avoids the need for model-specific formats. Simulations can mostly be run quickly, even with large datasets, which allows testing of the sensitivity of results to multiple input scenarios.

Wairoa has two different dispatch modules:

- The merit order module is best suited to systems that do not have significant network constraints and have significant intermittent generation.
- The Linear Program (LP) module is best suited to systems where network constraints have a significant impact on dispatch.

There is the option of feeding the results of the LP module back into the merit order module (e.g., by constraining some generator availability) in an iterative manner to get results that best represent reality.

A description of the two modules and their functionality is summarised in the table below.

Table 69 Comparison of Wairoa dispatch modules

	Merit Order Dispatch	Linear Program Dispatch
Type of calculation	Solves as an enumerative spreadsheet calculation	Includes network constraints and therefore needs to be solved as a LP and Mixed Integer Programming for unit commitment problems.
Speed of solve	Fast to run. It takes only a few seconds to solve a whole month (744 hours). It takes about 10 minutes to cycle through 20 years (240 months / 178,560 hours)	Slower to run and setup. It takes approximately 20 seconds to solve 24 hours. So, it is slow to run it across large timeframes. Representative days are typically used to model large time frames (e.g. a representative day for each month over 20 years, which is 240 model runs).
Approach to optimising hydro and battery storage	Optimises stored energy by smoothly ramping hydro dispatch down along the load duration curve[98]	Optimises stored energy within the LP formulation, so takes account of network constraints.

[97] 'Wairoa' means waterfall in Maori. It reflects ECA's strong links to New Zealand and the dispatch model's particular ability to optimise hydro and other storage-based power (such as batteries).
[98] Some other dispatch models simply 'turn on' stored energy generators at full capacity during the peak hours, until the stored energy (i.e. water) runs out, which is sub-optimal

	Merit Order Dispatch	Linear Program Dispatch
Key advantage	Solving every hour allows full modelling of the effect of intermittent renewables (for example by inputting historical hourly output profiles of solar and wind generators)	Can be used for a multi-regional dispatch, where network constraints exist and are likely to be binding. Can distinguish between up to ten regions, including accounting for interconnector losses and charges.

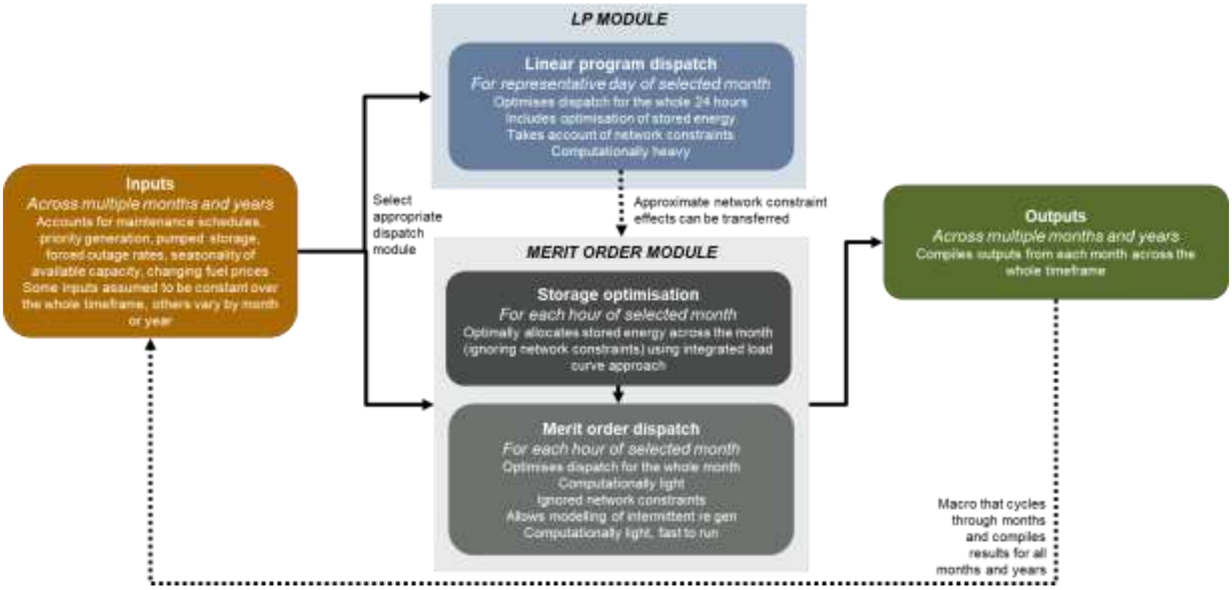
Source: ECA

Wairoa incorporates the following functionality:

- Definition of priority dispatch generators
- Modelling the intermittency/seasonality of renewables
- Optimisation of battery storage (for supplying energy)
- Least cost expansion decisions
- Accounting for forced outage rates
- Optimisation of hydro storage
- Accounting for hydro seasonality
- Treatment of pumped storage
- Accounting for maintenance schedules (if available)

Wairoa's model structure is summarised in the figure below.

Figure 42 Wairoa model structure



Source: ECA

Utilisation in the NIRP context

In the context of the NIRP, WAIROA is used as a long-term expansion and dispatch model. The objective is to simulate Namibia electricity market outcomes under different conditions, using both:

- Enumerative calculations to calculate costs.
- Excel Open Solver linear programming algorithm in order to capture annual hourly dispatch constraints and long-term capacity expansion

The Wairoa's objective function is to choose among the cheapest available facilities (while not exceeding their maximum capacity) in order to minimise the total system cost and meeting the total system demand. The methodology to solve the dispatch problem is called the 'merit order dispatch'. This problem is solved by:

- Ordering all available power plants by merit order (from the cheapest to the most expensive variable costs – O&M and fuel costs)
- Deploy the power plants to match the demand and additional reserve requirements above peak demand for any given hour. Thermal plant efficiencies and their fuel prices are fixed within a year, but we assume a varying hourly price to reflect TOU import tariffs.