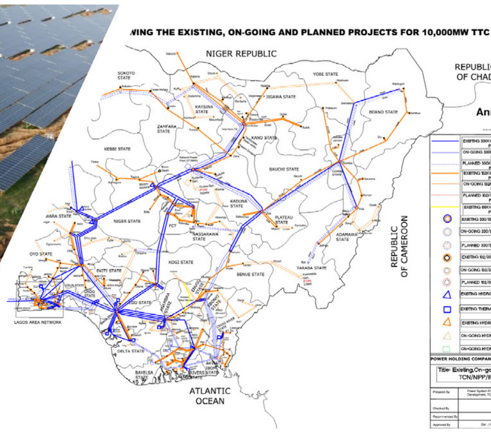
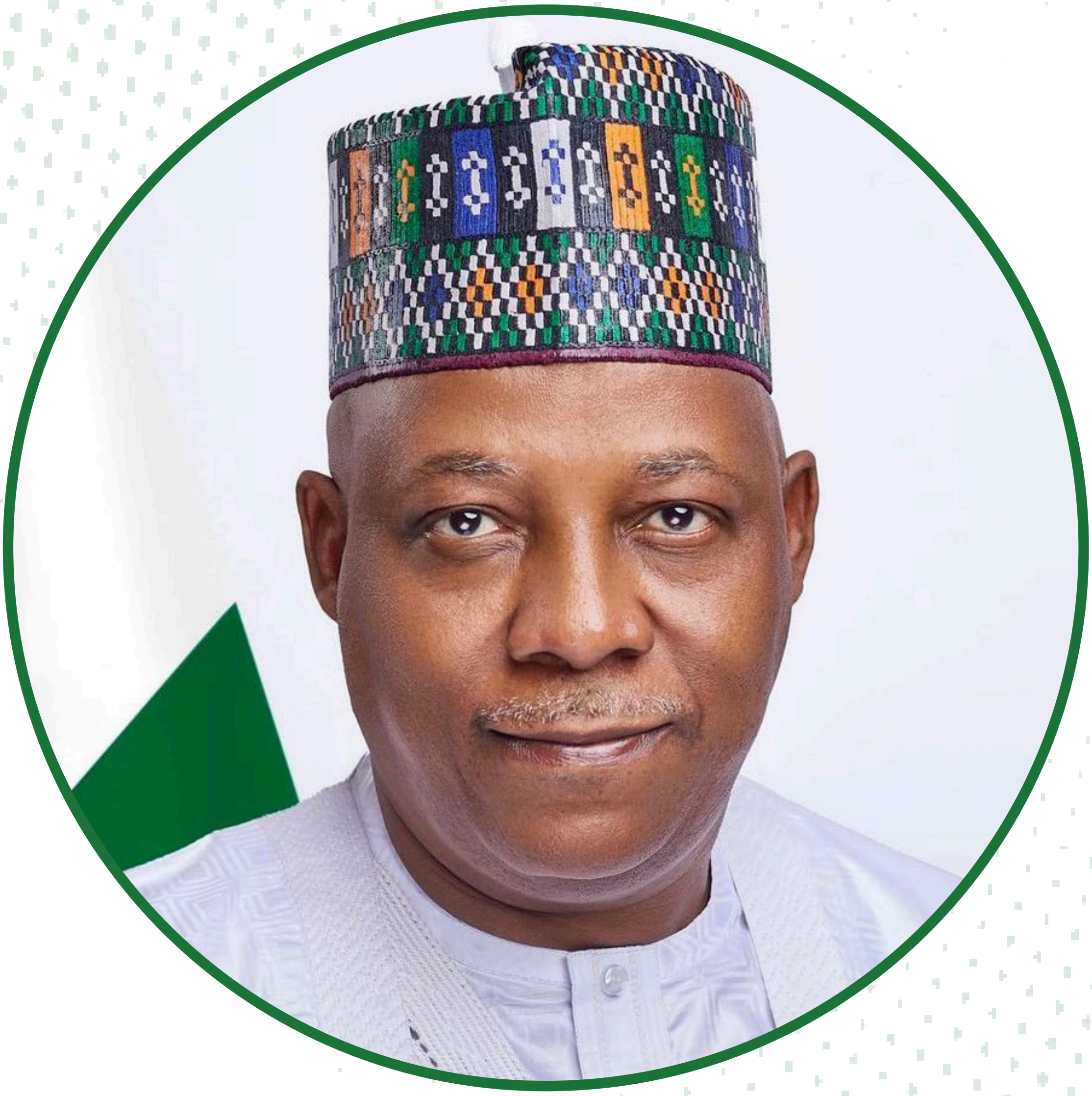


Nigeria Integrated Resource Plan 2024 (NIRP 2024)

Federal Ministry of Power

Bola Ahmed Tinubu GCFR

President of the
Federal Republic of Nigeria



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Honourable Minister of Power,
Federal Republic of Nigeria

Contents

List of Figures and Tables

Page

List of Acronyms

AEMO	Australian Energy Market Operator
BECCS	Bioenergy with carbon capture and storage
BESS	Battery energy storage systems
CCGT	Combined cycle gas turbine
CCUS	Carbon capture usage and storage
DESG	Delayed electrification and self-generation phase-out
DisCo	Electricity Distribution Company
DRE	Delayed emissions and RES targets scenario
DSM	Demand side management
ECA	Economic Consulting Associates
EE	Energy efficient
ETP	Energy Transition Plan
FGN	Federal Government of Nigeria
FMoP	Federal Ministry of Power
GB	Great Britain
GEAPP	Global Energy Alliance for People and Planet
GenCO	Generation Company
GW	Gigawatt
IPP	Independent power producers
NIRP	Nigeria's Integrated Resource Plan
ISO	Independent System Operator
LCOE	Levelised cost of energy
NERC	Nigerian Electricity Regulatory Commission
NIEP	National Integrated Electricity Policy
NIRP	Nigerian Integrated Resource Plan
NPSP	Nigeria Power Sector Programme
NPV	Net present value
PMO	Programme Management Office
PPA	Power Purchase Agreement
PPMC	Power Planning Monitoring Committee
PV	Photo-voltaic
RE	Renewable Energy
RES	Renewable energy supply

SAPP	Southern Africa Power Pool
SC	Single circuit
SDG	Sustainable Development Goals
SIP	Strategic Implementation Plan
TCN	Transmission Company of Nigeria
ToR	Terms of Reference
UKNIAF	The United Kingdom Nigeria Infrastructure Advisory Facility
VRE	Variable renewable energy
WAPP	West African Power Pool

Acknowledgements

The development of the Nigerian Integrated Resource Plan (NIRP) 2024 would not have been possible without the collective efforts and contributions of numerous stakeholders. Primarily, we acknowledge the critical role played by the Federal Ministry of Power (FMoP) and the Nigerian Electricity Regulatory Commission (NERC) in providing strategic direction and oversight. As such, we extend our deepest appreciation to the Chairman, Nigerian Electricity Regulatory Commission, Engr. Sanusi Garba, whose leadership and guidance have been instrumental to the successful execution of the NIRP development process.

Special thanks go to the members of the Steering Committee, for providing leadership and strategic direction, the NIRP Working Group whose dedication and expertise ensured that stakeholder input and guidance informed the choices of pathways followed towards the successful completion of this initiative, and the Transmission Company of Nigeria, for the helpful collaboration through this process. All of these contributions have laid the foundation for a sustainable and actionable NIRP.

We are equally grateful to our Development Partners, including the World Bank, the Global Energy Alliance for People and Planet (GEAPP), and the Nigeria Power Sector Program (NPSP) of USAID, amongst others, for their collaboration and unwavering support.

Our appreciation also extends to the United Kingdom Nigeria Infrastructure Advisory Facility (UKNIAF) for providing the technical assistance of the Economic Consulting Associates (ECA), whose expertise and diligence have been pivotal in the successful delivery of this premier edition of Nigeria's Integrated Resource Plan, the NIRP-2024.

Finally, none of all these would have been possible without the foresight and financial commitment of the UK Foreign Commonwealth and Development Office (FCDO) and UK Partnering for Accelerated Climate Transitions (UK PACT). For these, we remain very grateful.

NIRP-2024 will play a vital role in shaping Nigeria's energy future and achieving its commitments to the Nationally Determined Contributions (NDCs) and the Energy Transition Plan (ETP).

Chief Adebayo Adelabu OFR, FCA, FCIB

Honourable Minister of Power

Executive Summary

Integrated resource planning

An Integrated Resource Plan (IRP) is a comprehensive approach to National power system planning that includes on the supply side a holistic assessment of National energy resources and on the demand side opportunities for energy efficiency to derive a least cost combination of supply and demand measures that further National objectives such as energy security and access, social equity, decarbonisation and environmental sustainability.

The development of Nigeria's first NIRP is an imperative to address the crisis in the National power system which reinforces existing socioeconomic disparities and stifles national development. To take its place as the leading economy in Sub-Saharan Africa, Nigeria needs a national grid of commensurate size that provides reliable electricity at least cost and this is what is planned for in this NIRP.

This NIRP has been developed by a Technical Committee working with an expert IRP consultancy team, financed by the United Kingdom Nigeria Infrastructure Advisory Facility (UKNIAF). The process featured several consultations with different stakeholders including representatives from GenCos, DisCos, Government Agencies consumer groups, women-focused groups and a wide range of sector experts from across the electricity delivery value chain. The main steps in the process are the development of the demand forecast, resource assessment and identification of candidate generation projects, definition of policy scenarios and use of IRP software to derive the least cost results. Each of these steps is described in detail in separate reports, which are cross-referenced in an annex.

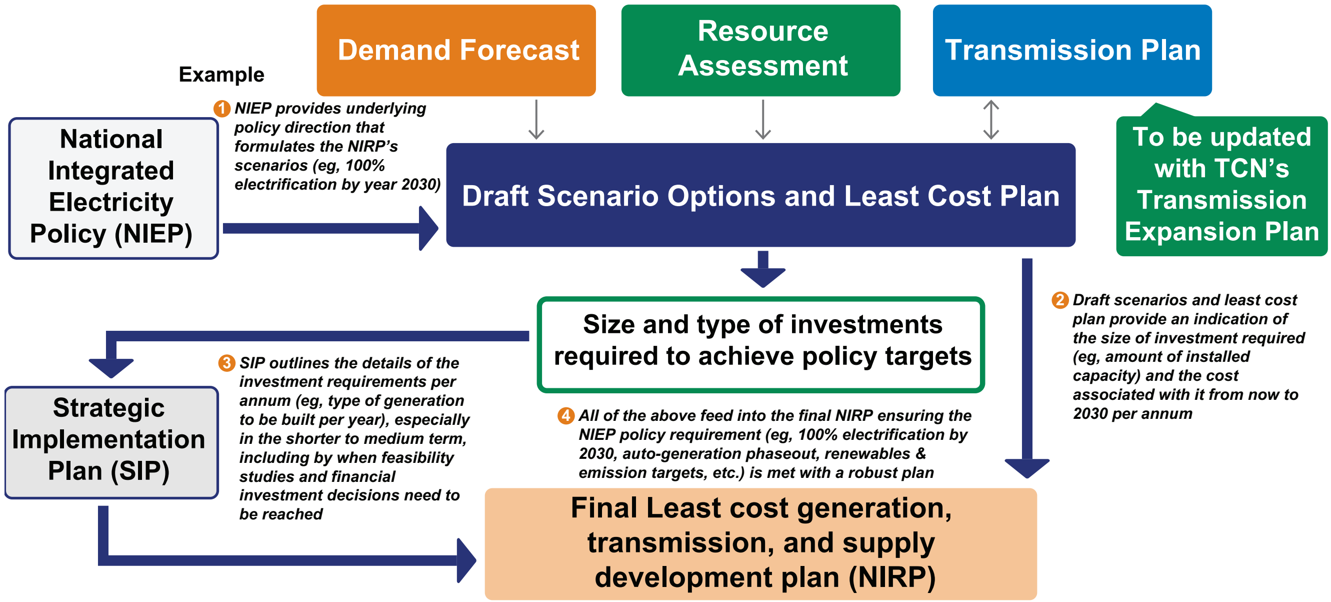
Integrated resource planning is a process rather than an event. It is important, therefore, that institutional structures be put in place for the implementation, monitoring and updating of the NIRP document and the report provides details on this. The first revision of the NIRP that is planned is the incorporation of the results of TCN's Transmission Master Plan, which is to be elaborated in 2025.

Planning under the Electricity Act 2023

As specified in the Electricity Act, 2023, the policy targets to be incorporated in the NIRP are those laid out in the National Integrated Electricity Policy (NIEP), one example being the policy to achieve universal access to electricity, with a 2030 target date. Using this policy as an example, the diagram below shows how the NIEP feeds into the NIRP scenario definition and least cost plan, with the outputs in terms of the size and type of investments feeding into the Strategic Implementation Plan (SIP). The SIP is envisaged in the Electricity Act to be a robust and practical implementation plan, the details of which will be included in the NIRP.

It is to be emphasised that the main driver of the NIRP is demand. The generation and transmission investments are made first and foremost to bring all current demand onto the National grid and to meet future growth in demand. The simultaneous meeting of policy targets, particularly environmental targets, is secondary to the main function of meeting demand.

Relationship between NIEP, SIP and the NIRP



State IRPs

In a country with a federal system of government like Nigeria, electricity planning should take place at both the State and the National level. Having an active role in the generation, transmission, distribution and regulation of electricity are functions recently restored to the States through the 2023 amendments to the Constitution of the Federal Republic of Nigeria, as well as the Electricity Act 2023. To play an effective role in the power sector, a few States have developed or are in the process of developing State-level IRPs. This is a welcome development, but it is necessary to establish a framework that will ensure compatibility between the National and State IRPs. The intention in this regard is to have a common data platform using compatible, shared software developed by Energy Exemplar.

Reinforcing the National grid for secure, least cost electricity

Notwithstanding the potential to enhance electricity supply through State-level involvement, it is important that the States do not adopt an autarchic approach in the power sector. There is a widespread belief that security of supply is best achieved through developing local sources of electricity, this is because of generations of Nigerians growing up in a country without adequate electricity from the National grid. In other countries where the National grid operates satisfactorily, local generation is seen as vulnerable and responsibility for security of electricity supply is assigned to the National grid.

The National level IRP is set to provide a National grid in Nigeria that will deliver security of supply within the planning parameters that have been set. In the case of the NIRP, these parameters are Loss of Load Expectation starting at 100 hours/year in 2024 and decreasing to a final value of 24 hours/year in 2035, plus a requirement that spinning reserves be set at the value of 900 MW.

Formulation of the NIRP scenarios

The choice of scenarios for the NIRP has been stakeholder-driven with the first formal discussion being in the Working Group workshop held in Abuja in September 2023. The phasing out of self-generation is a national imperative, but the consensus from earlier discussions is that the 2030 target is unattainable and it would be prudent to plan for the transition to have taken place by 2035. Similar concerns are raised about the target date for the achievement of universal access, 2035 being considered still challenging but more realistic than 2030.

The above informed the decision for the Delayed Electrification and Self-Generation phase-out (DESG) scenario being the basis for the NIRP. This scenario adopts the base demand projection and produces least cost results which meet the Renewable Energy Supply (RES) penetration and Energy Transition Plan (ETP) emissions targets. In anticipation of DESG being the preferred scenario, the four sensitivities conducted at the generation-only stage of the modelling were relative to the DESG scenario rather than the Base Scenario, and the battery energy storage systems (BESS) with negative emissions sensitivity reduced the DESG costs. Hence for the NIRP scenario a modification of the DESG scenario was adopted that has bioenergy with carbon capture and storage (BECCS) with negative emissions as a candidate option.

Criticality of the Network

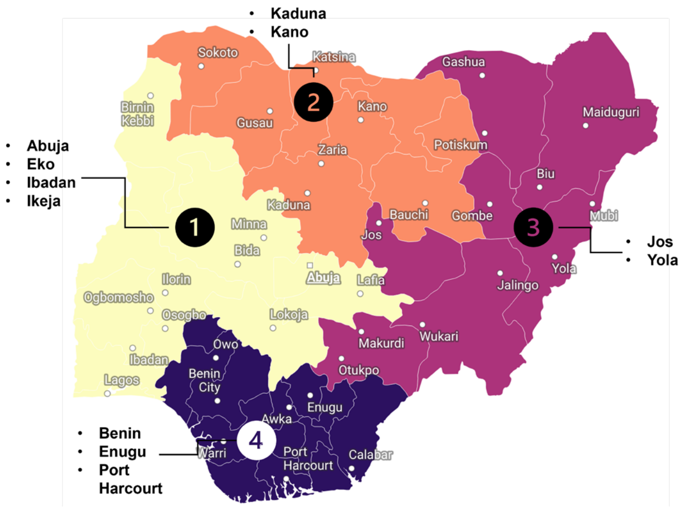
Future iterations of the NIRP, when aligned with TCN's Transmission Master Plan, will be able to capture the real extent of network development requirements at a transmission level beyond the four zones of this NIRP but also within them. Network development needs to happen in tandem with generation development to achieve least cost development. If network development, which requires only a portion of the financial resources that generation requires, is delayed the result is underutilised or curtailed (in the case of RES) generation assets, as can be seen in Nigeria and other countries. Furthermore, distribution network development will also play a significant role in enabling the successful electrification of Nigeria and will have to be planned at a distribution level in conjunction with the National transmission and generation expansion plans.

The NIRP is a high-level planning instrument: the detailed individual investment projects are to be fleshed out through feasibility studies and at a regional level through the interaction of the NIRP with the SIP, as described in Section 2.1. In addition, the build-out of transmission lines is not enough because a network development plan must ensure that the grid can operate within operational limits. This will include the importance of wider investments in the grid such as reactive compensation and protection schemes, mentioned by TCN during the 7 November 2024 workshop. These will be captured in TCN's Transmission Master Plan and in the future through the more holistic role the Independent System Operator (ISO) will adopt.

NIRP modelling

Only limited transmission planning data is currently available. This has been used to provide a simplified four zone representation of the Nigerian power system, as shown in the map below. It must be emphasised that the current NIRP is based on a simplified generation-transmission zonal model developed to provide indicative results that show what the consequences are of considering the location of demand centres and generation sources. It will be enriched and finalised when detailed transmission data becomes available from TCN's Transmission Master Plan.

Transmission model zonal split



Source: NIRP Technical team using Datawrapper

Model results for the NIRP scenario with transmission

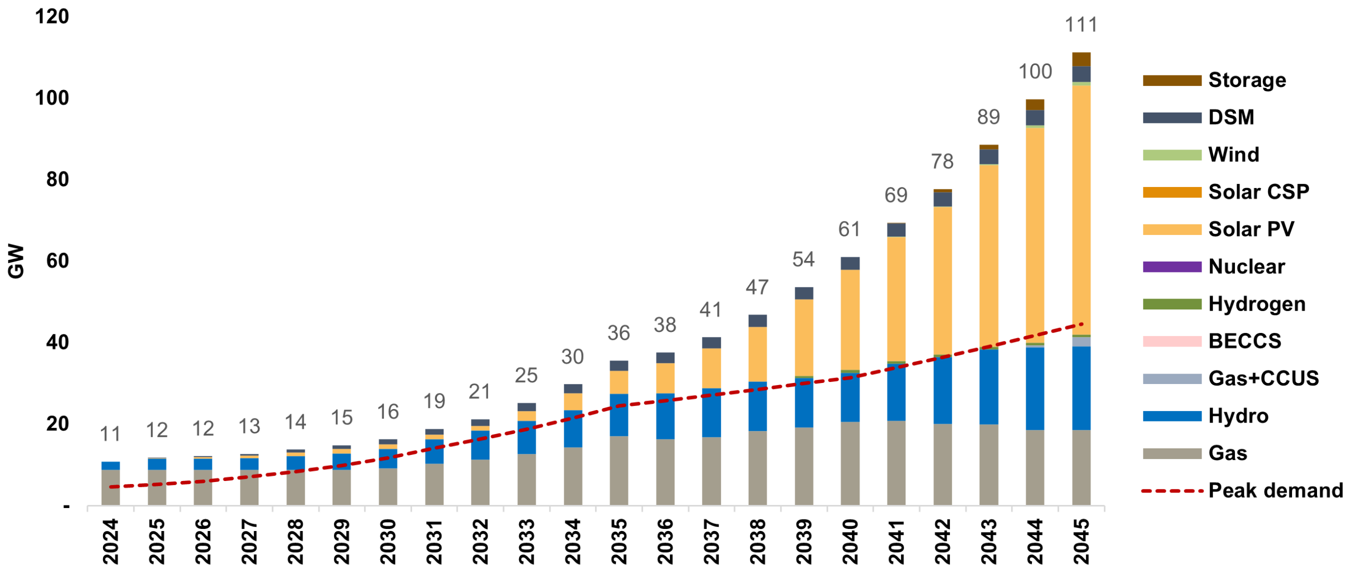
The National level results of the NIRP scenario are given in the table and figures below. With the RES capacity share at 37% in 2030, the National renewable energy target of 30% by 2030 is easily exceeded. This shows that more renewable generation is least cost.

Summary of results – NIRP scenario

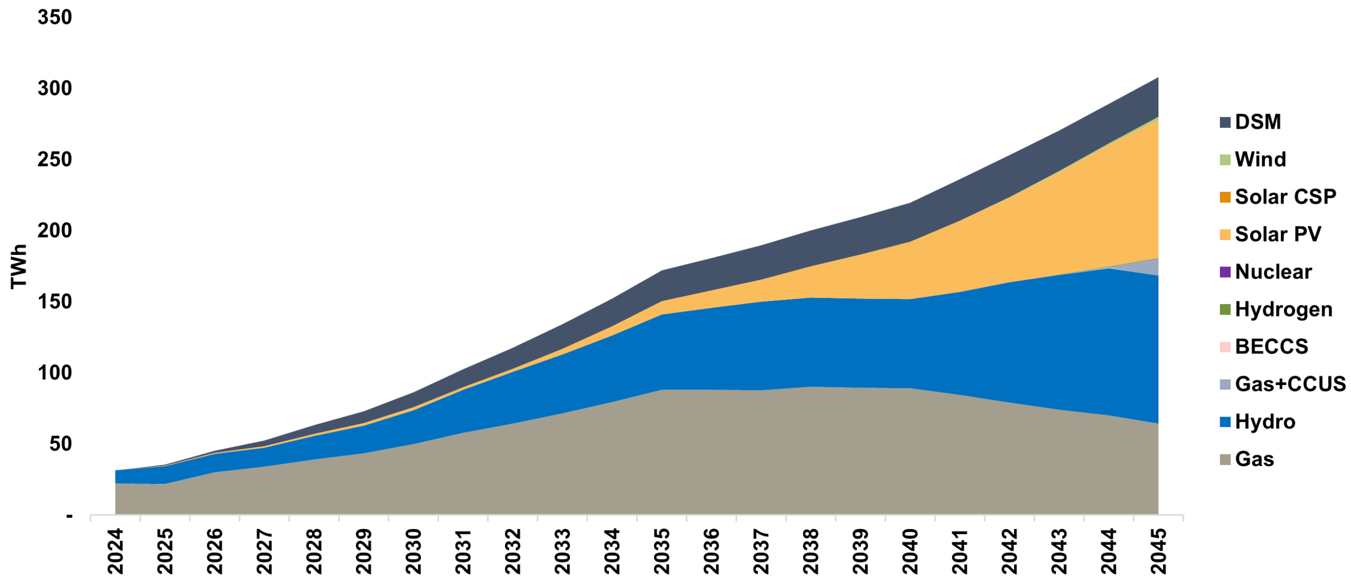
	Unit	2024	2030	2040	2045
Peak demand	*GW*	5	12	31	45
Installed capacity (incl. storage)	*GW*	11	16	61	111
RES capacity	*GW*	2	6	37	83
Storage capacity (incl. solar CSP storage)	*GW*	-	-	-	3
Storage energy capacity (incl. solar CSP storage)	*GWh*	-	-	-	11
Average storage duration	*hrs*	-	-	-	3
RES capacity	*% of total*	18%	37%	61%	75%
Energy demand	*TWh*	30	78	209	301
Storage demand	*TWh*	-	-	-	4
Generation	*TWh*	31	86	220	308
Share of RES	*%*	29%	34%	54%	73%
Short run marginal costs	*$/MWh*	27.8	23.4	15.4	36.1
		2024-45	**Cost %**		
NPV of total costs	*bn$*	63	100%		
NPV of capex	*bn$*	40	63%		
NPV of transmission costs	*bn$*	0.3	0%		
NPV of fuel costs	*bn$*	9	14%		
NPV of variable O&M	*bn$*	7	11%		
NPV of fixed O&M	*bn$*	8	12%		
LCOE	*$/MWh*	49.3			
LCOE	*c$/kWh*	4.93			
Total emissions	*mtCO2eq*	644			

Note: $ are USD in 2022 prices

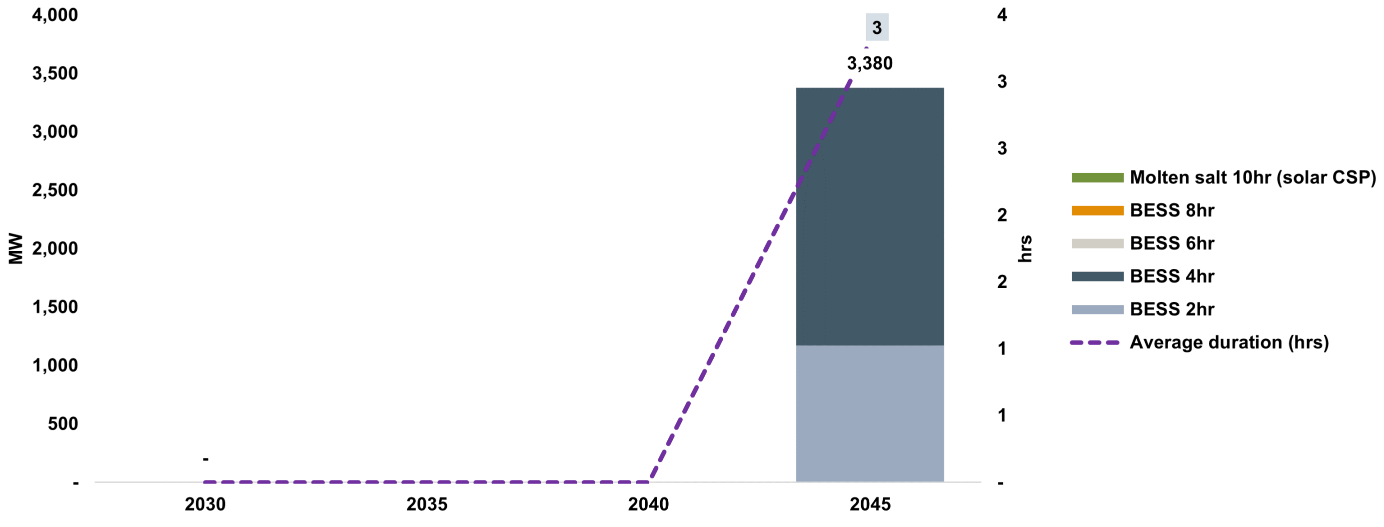
Installed capacity 2024-45 – NIRP scenario



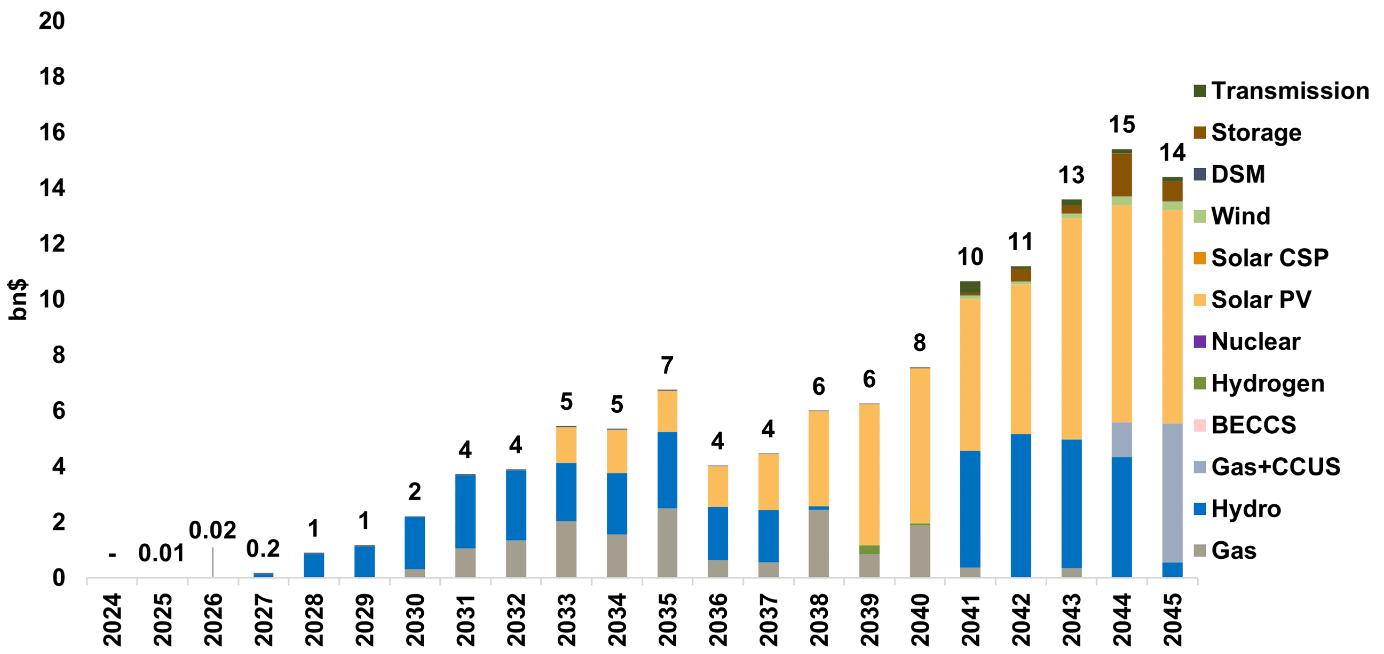
Generation 2024-45 – NIRP scenario



Storage capacity and duration



Investment costs 2024-45 – NIRP scenario



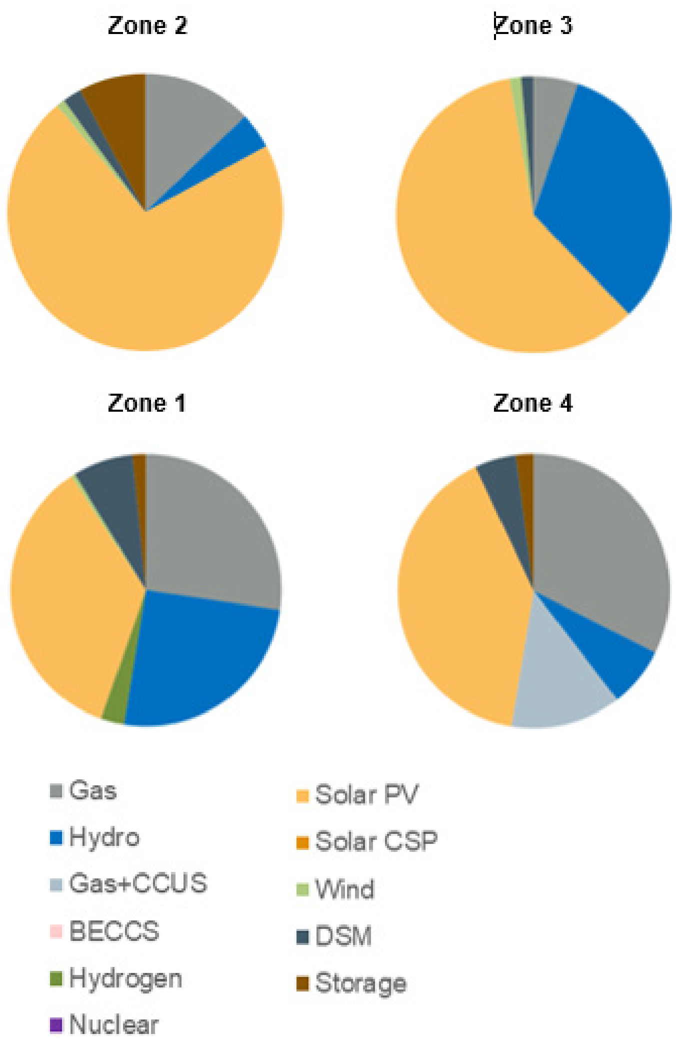
The transmission network investment costs included in the model are minimal (~$1 bn), but this does not reflect the critical role of transmission which shapes the least cost generation investments in the different zones. The low levels of investment expenditure in the early years that is illustrated in the graph above is because there is excess generation capacity at the start of the planning period and because the extent of transmission network development required within each zone is not captured. The excess generation cannot meet demand because of a lack of transmission capacity. There will be substantial expenditures in those years on TCN's ongoing investment projects which are set to significantly increase transmission capacity on the National grid, and in addition distribution network investments. The NIRP model assumes that the transmission capacity increase will come on stream, but the expenditures on TCN's ongoing projects are not reflected in the graph above.

To put the costs of ongoing transmission line projects into context, some indicative costs using data inputs from TCN and the Working Group have been calculated. The indicative costs of the 16 inter-zonal transmission lines total to $192 million. When compared to the generation investment costs, transmission costs are small so do not make a difference to the NPV of total costs.

Zonal results of the Draft NIRP (M11) scenario

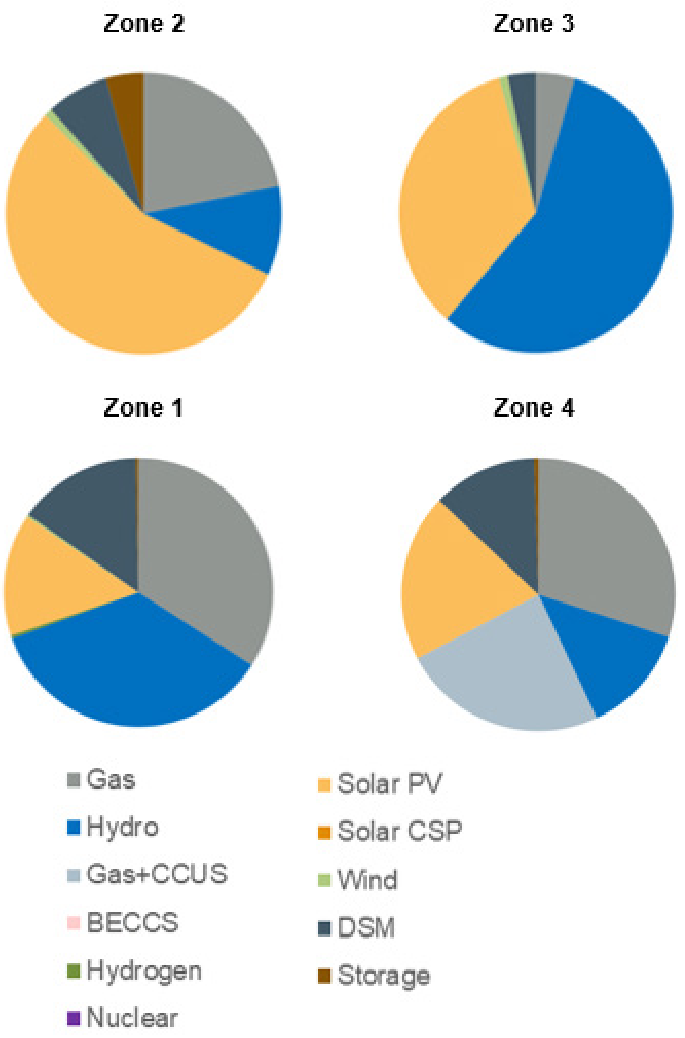
The least cost solution in 2045 includes some gas capacity in each region, but particularly zone 1 and zone 4, where a significant portion of the thermal capacity is Gas+CCUS. By contrast, installed capacity in zone 2 and 3 is solar PV with associated storage. Hydro capacity is predominantly in zone 1 and zone 3, where more hydro sites are identified.

Installed capacity (GW) by technology and zone in 2045



Energy generation by technology and zone in 2045 is illustrated in the second set of pie charts given below. These graphs accentuate the picture of northern solar PV vs southern gas. The solar in zone 3 is complemented by hydropower, while in zone 2 the solar PV is matched by gas and energy from storage, plus a range of other technologies. The other two zones have some energy from solar PV but rely more heavily on gas and hydro (zone 1) and Gas+CCUS (zone 4).

Energy generation (TWh) by technology and zone in 2045



To make best use of the different types of generation in the different zones, optimal operation of the National power system requires strong north-south transmission interconnectors. This stands in contrast to the emphasis in the current transmission investments which are more focussed on east-west inter-zonal connectors. Looking at the data we have received on existing transmission lines, there are currently ten transmission lines connecting the northern and southern zones[1] while 20 connect the eastern and western zones.

Sensitivities

Four sensitivities on the DESG scenario were conducted at the generation-only modelling stage. These were not being repeated because the impact on the NIRP results can readily be deduced from the previous work:

- ***downside sensitivity:*** higher fuel prices were not found to have a large impact on the overall results because of the limited role of gas, with this declining significantly towards the net zero year (2060). In the context of the NIRP zonal model, higher gas prices have differential impacts with zones 1 and 4 being much more severely affected than the solar-dominated zones 2 and 3.
- ***upside sensitivity:*** reductions in the capital costs of RES and BESS technologies were found to have a significant beneficial impact, giving scope for higher levels of renewables investments and reduced expenditure on fuel. In the zonal model, the impact is again differential, with zones 2 and 3 which have the best solar resources benefitting more than zones 1 and 4.

The additional sensitivities that have been carried out for the NIRP report are:

- ***low demand:*** replacing the base case demand forecast, which had an energy growth rate of 7.7% per year up to 2045 (328.6 TWh), with the low demand projection (annual average growth rate of 5.9%, reaching 221.8 TWh in 2045).
- ***reduced water availability for hydro:*** the impact of possible future reductions in the availability of water for hydropower generation, due to climate change or other factors, was tested by restricting capacity factors at hydro plants to half of their base values.

The main driver of the investment sequence in an IRP is demand, so it is not surprising that the results are highly sensitive to the rate of growth of demand. While peak demand is one-third less than the base peak demand in 2045, installed capacity is 55% lower with total costs and LCOE lower by 41% and 23% respectively.

The assumption of reduced water availability for hydro-generation has the effect of requiring additional capacity to be installed (23% higher by 2045) with total costs and LCOE higher by 30% and 28%, respectively. As Nigerian hydropower rivers are less prone to climate changed-induced drought than is the case in other countries in Sub-Saharan Africa, the results of the sensitivity test may alternatively be interpreted as illustrating how important hydropower is in the NIRP least cost solution.

Modelling conclusions and recommendations

As emphasised in Section 4.1, the Draft NIRP (M11) NIRP scenario results are to be treated as indicative. It

[1] Zone 1 to 2, 1 to 3 and 3 to 4

will only be possible to produce a comprehensive NIRP when the generation and transmission planning can be iteratively coordinated to converge on the overall least cost solution. It is nonetheless the case that the M9 Final scenario options and least cost plan and Draft NIRP (M11) modelling results have provided some important insights for IRP planning in Nigeria. The following summary points can be highlighted:

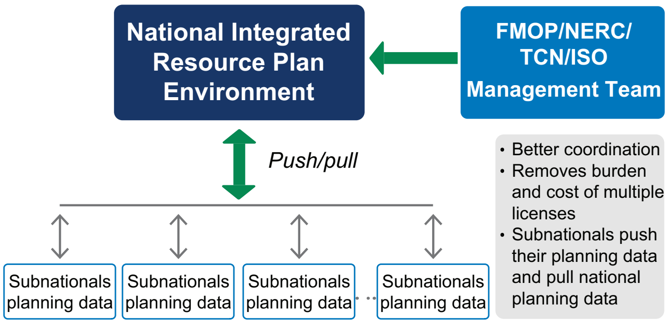
- **Demand:** growth in demand is the fundamental driver of the generation and transmission investment sequence. The results are highly sensitive to the demand forecast. The out-turn should be monitored, and the forecast continually updated so that appropriate adjustments can be made to the NIRP during implementation.
- **Electrification and Self-generation Policy Targets:** as discussed in this report, the 2030 target for the achievement of universal electrification and the phasing out of self-generation are widely considered not to be feasible and hence the target year for these two objectives has been shifted in the final Draft NIRP (M11) analysis to 2035. Even this year will be very challenging and a concerted effort across a number of fronts will be needed if they are to be attained. As estimated for the M9 Final scenario options and least cost plan Report in a parallel model, a 5-year delay to 2035 will result in $29 bn of additional costs and an additional 90 mtCO2eq of emissions. Replacing self-generation with access to reliable grid electricity will be a major boost to investment, economic growth and enhanced standards of living.
- **Renewable Energy and Emissions Policy Targets:** National renewable energy and emissions reduction targets for 2030 and 2050 are readily absorbed into the NIRP but become very challenging close to the net zero target year of 2060. Planning ahead for net zero in 2060 has implications for least cost investments in earlier years such as 2045.
- **North and south:** the final Draft NIRP (M11) modelling has confirmed that the northern part of Nigeria is set to become the country's solar energy powerhouse. Storage to firm the solar will become increasingly important, with a mix of battery storage and CSP molten salt storage being chosen as part of the least cost investment sequence. To 2045 the southern region will continue to rely on gas generation, though this will increasingly be combined with CCUS. Hydropower is an important component of the generation mix and all opportunities for developing hydropower (run-of-the-river as well as storage schemes) should be taken up.
- **Hydropower** is an important component of the generation mix, covering 33% of the total energy generation in 2045, and all opportunities for developing hydropower (run-of-the-river as well as storage schemes) should be taken up. The sensitivity test on reduced hydrological flows emphasises the importance of hydropower in the least cost solution for the NIRP: curtailment of hydropower would necessarily require investments in more expensive technologies.
- **Transmission:** To make best use of the different types of generation in the different zones, optimal operation of the National power system requires strong north-south transmission interconnectors. This stands in contrast to the emphasis in the current transmission investments which are more focussed on east-west inter-zonal connectors. The importance of network development is critical and future iterations of the NIRP should capture a more complete view of network development requirements and their interrelation with generation expansion, in the first instance when TCN's Transmission Master Plan is complete.
- **Flexibility:** in addition to the analysis underpinning an IRP relying on a multiplicity of data, there is a wide range of uncertainties that impinge on the implementation of an IRP. It is advantageous therefore to emphasise flexibility. The outcome of the NIRP can be improved by periodically updating the analysis on the basis of improved data and taking action when real world uncertainties are resolved (whether this be adversely, such as capital or fuel costs being higher than expected, or advantageously, such as more water than expected being available for hydro-generation). Good monitoring of the NIRP is needed – proposals on this are given in Section 6 below.

Implementation of the NIRP

The nature of integrated resource planning is that it is a process, rather than an event marked by the publication of the NIRP document. To be effective, an IRP needs to be consistently implemented, carefully monitored and periodically updated. In Nigeria's case, there is the additional challenge that the National IRP needs also to be coordinated with the State IRPs which will always be at different stages of development and implementation.

The proposal is that the NIRP process will initially be the responsibility of a joint **Federal Ministry of Power (FMoP), Nigerian Electricity Regulatory Commission (NERC) and Transmission Company of Nigeria/ Independent System Operator (TCN/ISO)** Management Team. As noted above, subsequently the responsibility will be assumed by the **Independent System Operator (ISO)** which is currently being established as an independent entity from TCN, in conformity with the provisions of the 2023 Electricity Act. When the ISO is established, a regulatory instrument will be implemented by NERC to ensure the NIRP remains a dynamic and live process that gets updated periodically. The relationship between National and Sub-National planning is illustrated in the diagram below.

Institutional structure for integrated resource planning in Nigeria



Effective monitoring of an IRP is important to ensure that the flexibility and adaptability that has been built into the plan at the design stage is realised. It is recommended that the SIP and the NIRP be monitored by a focussed **Power Planning Monitoring Committee (PPMC)** of mid-level officials drawn from FMoP, NERC, TCN, ISO, ECN and representatives of the States. When the ISO assumes responsibility for the NIRP, the PPMC will be chaired by the ISO.

When the ISO is established and assumes responsibility of the NIRP, it is proposed that a regulatory instrument will be issued by NERC, transferring the NIRP PMO to ISO and mandating the ISO to ensure the NIRP remains a dynamic and live process that gets updated periodically. This will be monitored by NERC as a requirement by the ISO. The details of this regulatory instrument are to be finalised in due course

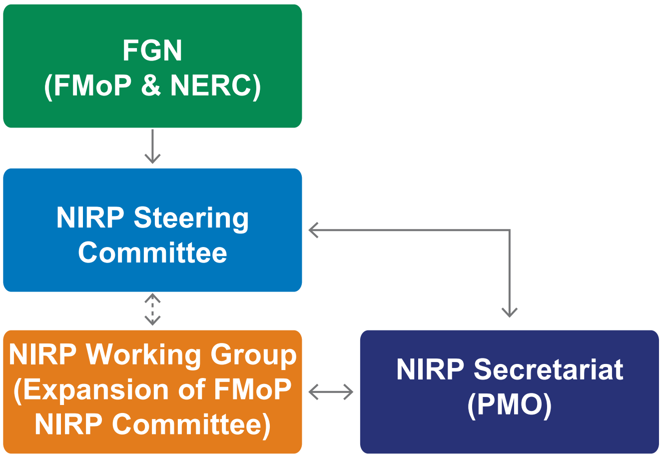
The PPMC will report to the NIRP Management Team and subsequently, when the ISO assumes responsibility for the NIRP, to the ISO. At points in the future where the NIRP is to be updated, the PPMC, working with the broader coalition of stakeholders represented on the current NIRP Working Group, would take the lead on this.

This model for monitoring an IRP has been successfully deployed in other African countries. The experience has been that the members of the PPMC do not just turn their attention to planning when the annual retreat is due, but instead become involved in continuous monitoring and exchanges with other committee members throughout the year. This helps to enhance job fulfilment and break down the barriers which exist in all countries between different agencies in the electricity sector.

The NIRP Programme Management Office

Executing the day-to-day undertakings of the NIRP along with the technical teams who engaged to support its preparation, implementation, and adaptation will be the task of the NIRP Project management Office (PMO), established as an entity within the FMoP/NERC/TCN-ISO Management Team (subsequently, ISO Management Team). The governance structure and working relationships of the PMO are illustrated in the diagram below.

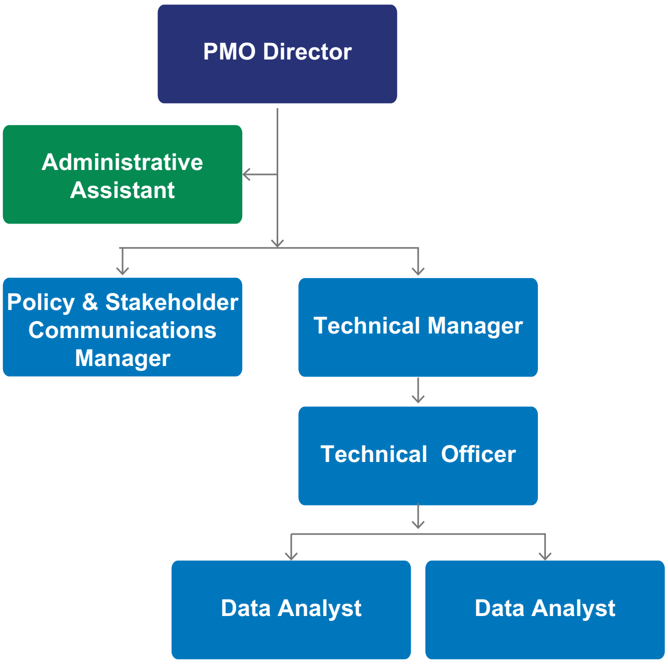
NIRP Governance Structure and Working Relationships



Note: The governance structure relates to the 'FMoP/NERC/TCN-ISO Management Team' in the previous diagram.

The structure and staffing of the PMO needs to ensure that the team receives overall strategic leadership and relevant technical expertise while also allowing for the efficient management of the NIRP process. The organisational chart is shown in the diagram below.

PMO organisation chart



Modelling and PLEXOS software adoption

The most important aspect of the NIRP modelling is the NIRP PLEXOS model itself. The current NIRP model will provide the basis for the more detailed NIRP model which will be developed in tandem with TCN's Transmission Master Plan during 2025. The current model will be transferred to and owned by FMoP, NERC and TCN/ISO at the first instance and the ISO thereafter. Provision has been made for training of dedicated personnel.

Discussions have been held with NERC and TCN with a view to ensuring a smooth transition and adoption of the PLEXOS software and its use for the purposes of the IRP at a National and at a state level. Discussions on the hand over, licence procurement and setup, and the training of the PMO staff are ongoing and will follow the handover of the NIRP to NERC initially and the ISO when established.

1 Introduction

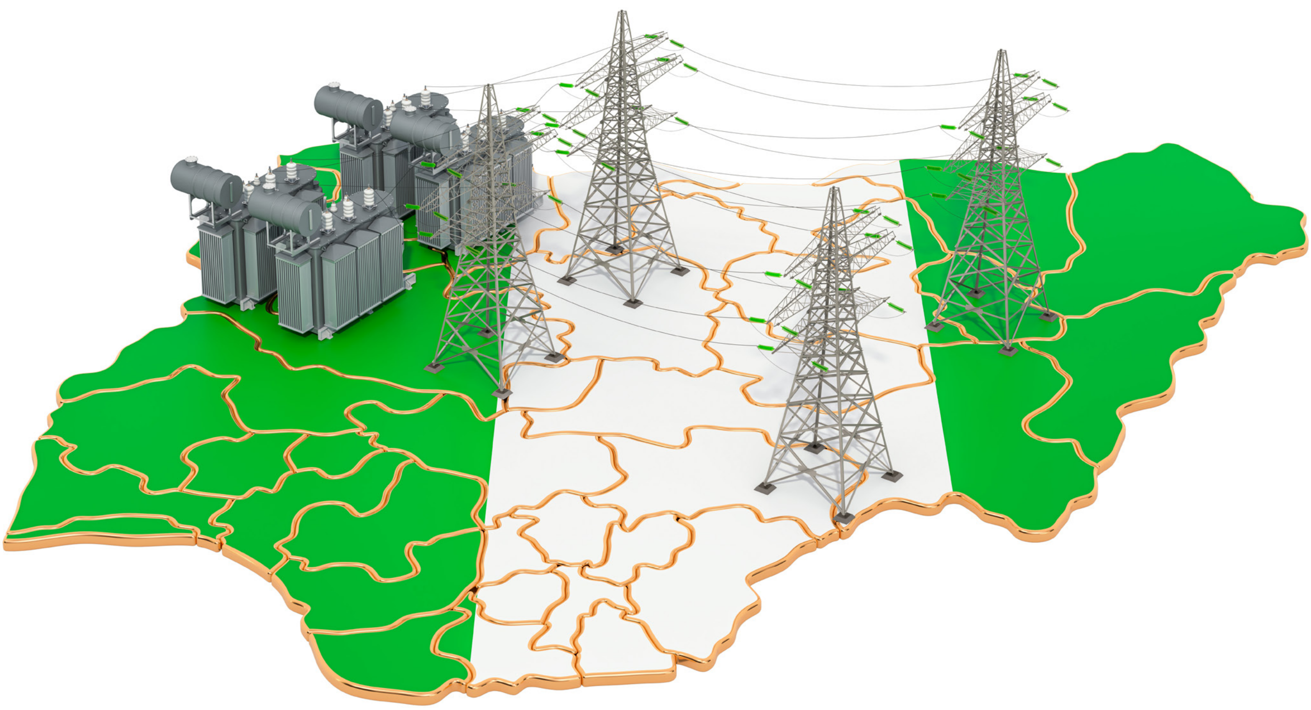
1

Introduction

An integrated resource plan (IRP) is a comprehensive approach to National power system planning that includes on the supply side a holistic assessment of National energy resources and on the demand side opportunities for energy efficiency to derive a least cost combination of supply and demand measures that further National objectives such as energy security and access, social equity, decarbonisation and environmental sustainability.

The development of Nigeria's first NIRP is an imperative to address the crisis in the National power system which is constraining the country's socio-economic development. At present only 50% of the population has access to electricity via the National grid[2], and those with access are subjected to frequent outages and load shedding. Many consumers have resorted to providing their own electricity, with self-generation currently being of the same order of magnitude as grid supplies. Most of the self-supply is via diesel or petrol generators, which is very costly for consumers, the National economy and the global environment. There is an urgent need to expand grid supplies rapidly to eliminate self-generation, maximise utilisation of Nigeria's resources (especially RES in the form of hydro and solar), as well as to provide electricity for new productive sector investments and new household consumers.

To take its place as the leading economy in Sub-Saharan Africa, Nigeria needs a national grid of commensurate size that provides reliable electricity at least cost.
The starting point is on-grid capacity of only 10.8 GW consisting mainly of gas and hydropower generators. The transmission system cannot move all the power that can be generated to consumers, so only 5.2 GW (48%) of the installed capacity is utilised, and this is part of why there is reliance on self-generation. The NIRP that is laid out below envisages self-generation being eliminated by 2035 and on-grid generation capacity plus storage growing to 111 GW by 2045, with a generation mix by that stage that includes significant solar photo-voltaic (PV) generation supported by battery storage. Although requiring much smaller financial commitments, the parallel development of the National transmission system will be of critical importance, a theme that is elaborated below in Section 3.



[2] Energy Transition, Samuel Ajala, 2024 How local renewable grids are providing access to affordable electricity in Nigeria

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This NIRP has been developed by a Technical Committee working with an expert IRP consultancy team, financed by The United Kingdom Nigeria Infrastructure Advisory Facility (UK-NIAF). The main steps in the process are the development of the demand forecast, resource assessment and identification of candidate generation projects, definition of policy scenarios and use of IRP software to derive the least cost results. Each of these steps is described in detail in separate reports, and readers wanting more detail can find cross-references in Annex A.

This first NIRP document is a step along the way, rather than an endpoint. This is because IRP is best considered as a dynamic process rather than an event. A plan is not useful unless it is implemented, so the primary aspect of NIRP as a process is the arrangements for the implementation of the plan, together with provisions for monitoring and fine-tuning, as described below in Section 6. When the ISO is established and assumes responsibility for the NIRP, a regulatory instrument will be implemented by NERC to ensure the NIRP remains a dynamic and live process that gets updated periodically. This will be monitored by NERC as a requirement by the ISO.

In this case an early revision of the plan presented here is called for because the simultaneous development of the generation and transmission aspects of the NIRP was constrained by different timetables for the NIRP and TCN’s Transmission Master Plan, which is to be delivered in 2025. As discussed in Section 4.1, this first version will be enhanced and finalised when the transmission planning results are available and can be fully incorporated into the second version of the NIRP during 2025.

2

Planning under the Electricity Act 2023

2

2.1 National-level IRP

Traditional power system planning selects generation and transmission projects to minimise the cost of meeting forecast demand for electricity (both peak demand measured in GW and energy demand measured in TWh). This approach is still at the core of an IRP, but in an IRP close attention is paid to:

- National primary energy resources that can be used for energy generation, including renewable resources.
- the demand forecast, including considering how DSM and more efficient use of energy could reduce the growth of demand that has to be met through costly investments.

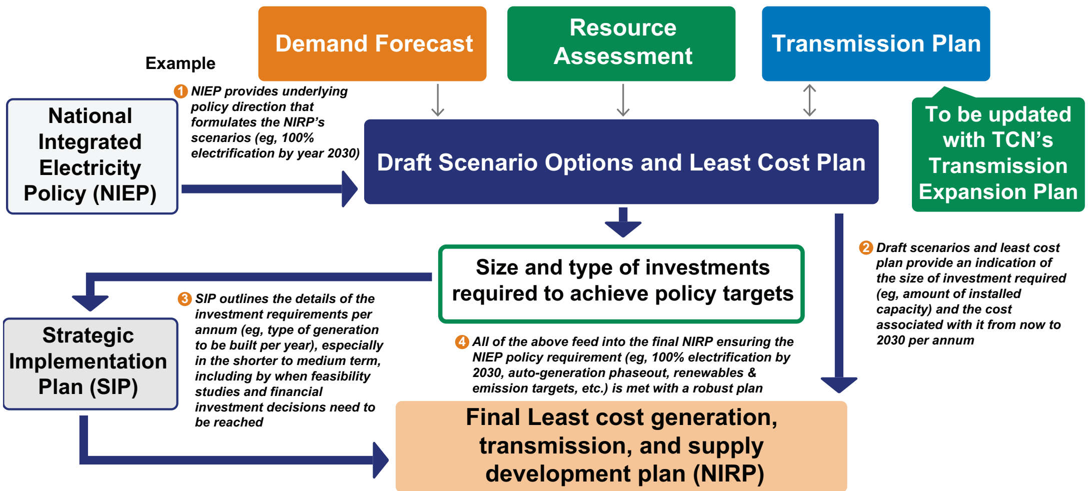
The complexity of IRP planning makes it essential to use one of the sophisticated planning tools that is available. These combine a data base for the systematic collation and storage of the multifaceted data that is required for IRP planning with optimisation algorithms to make use of the data to produce results for different scenarios.

The tool chosen for the NIRP is called PLEXOS, developed by a company called Energy Exemplar. At its core, PLEXOS provides the minimum of total costs (capital, O&M and fuel costs) to meet demand subject to implementation practicalities. The output measure that is used for ranking scenarios is the net present value (NPV) of the costs or the closely related LCOE, while the output itself is the sequence of generation and transmission investment projects that delivers the least cost solution for the chosen scenario.

As specified in the 2023 Electricity Act, the policy targets to be incorporated in the NIRP are those laid out in the National Integrated Electricity Policy (NIEP), one example being the policy to achieve universal access to electricity, with a 2030 target date. Using this policy as an example, the diagram below shows how the NIEP feeds into the IRP scenario definition and least cost plan, with the outputs in terms of the size and type of investments feeding into the Strategic Implementation Plan (SIP). The SIP is envisaged in the Electricity Act to be a robust and practical implementation plan, the details of which will be included in the NIRP, as discussed in Section 6.

It is to be emphasised that the main driver of the IRP is demand. The generation and transmission investments are made first and foremost to bring all current demand onto the National grid and to meet future growth in demand. The simultaneous meeting of policy targets, particularly environmental targets, is secondary to the main function of meeting demand.

Figure 1: Relationship between NIEP, SIP and the NIRP



Source: NIRP Technical team

2

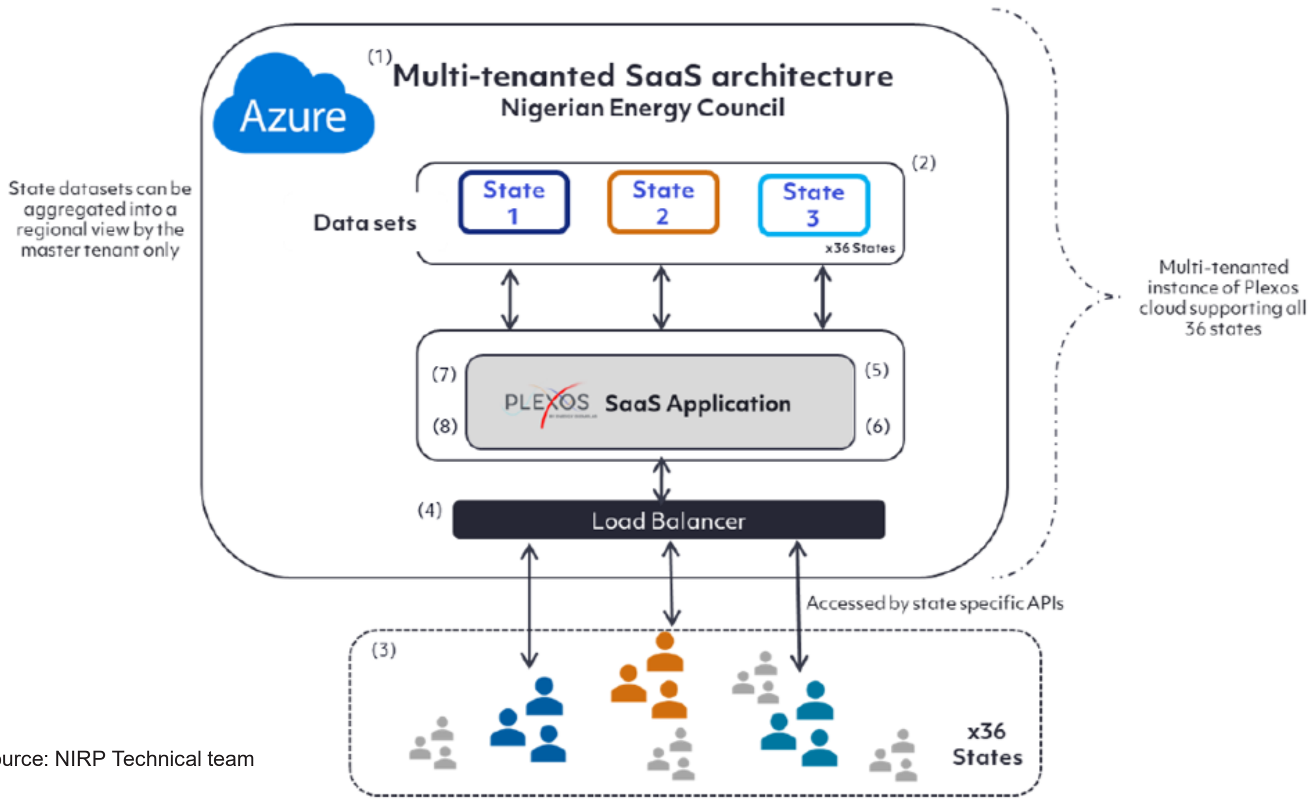
2.2. State IRPs

In a federal country like Nigeria, electricity planning should take place at both the State and the National level. Having an active role in the generation, transmission, distribution and regulation of electricity are functions recently restored to the States through the 2023 Constitution amendment as well as the enactment of the Electricity Act 2023. To play an effective role in the power sector, a few States have developed or are in the process of developing State-level IRPs. This is a welcome development, but it is necessary to establish a framework which will ensure compatibility between the National and State IRPs. The intention in this regard is to have a common data platform using compatible, shared software developed by Energy Exemplar. The relationship is illustrated in the diagram below.

Figure 2: Software integration of State-level and National integrated resource planning

Opening the electricity sector to the States has several significant advantages. As discussed at the UK-NIAF Roundtable in October 2023[3], these include:

- **Investment flows:** attracting local and foreign investment through new state market structures enabling investment in local generation (solar farms, small hydros, non-associated gas from inland basins) and in distribution.
- **Transmission:** state governments collaborating with transmission companies to extend and improve network resilience, including local strengthening of the National transmission grid, for example through resilient ring circuits.
- **Accelerated electrification:** including working with the Rural Electrification Agency to accelerate the deployment of and interconnection of mini grids.
- **Enhancing market competition:** further decentralisation and unbundling of the power sector and enabling market competition at the distribution sub-sector with the licensing of new entrant electricity distribution utilities.



Source: NIRP Technical team

[3] Presentation available from Nigeria Governors' Forum

2.3. Reinforcing the National grid for secure, least cost electricity

Notwithstanding the potential to enhance electricity supply through State-level involvement, it is important that the States do not adopt an autarchic approach in the power sector. As a result of generations of Nigerians growing up in a country without adequate electricity from the National grid, there is a widespread belief that security of supply is best achieved through developing local sources of electricity. In other countries where the National grid operates satisfactorily, local generation is seen as vulnerable and responsibility for security of electricity supply is assigned to the National grid.

The National level IRP is set to provide a National grid in Nigeria that will deliver security of supply within the planning parameters that have been set. In the case of the NIRP, these parameters are Loss of Load Expectation starting at 100 hours/year in 2024 and decreasing to a final value of 24 hours/year in 2035, plus a requirement that spinning reserves be set at the value of 900 MW.

Besides security of supply, a properly functioning National grid will provide lower cost electricity than can be produced locally, even after factoring in losses on the transmission system. This is primarily because of the significant economies of scale which exist in the power sector. The unit cost of generation from a large power plant will generally be much lower than the cost from a small plant. A National grid makes it possible to develop large, National-scale power plants that would not make sense if developed purely for the local market where the plant is located.

State vs National power in Nigeria is analogous to National vs regional approaches in the power pools around the Africa continent, the most developed one being the Southern Africa Power Pool (SAPP). The countries of southern Africa all have their own IRPs but there is also a higher-level plan, referred to as the SAPP Pool Plan. The current plan covering 2016-2040 offers savings of $39 billion when compared with the countries pursuing autarchic approaches. The savings arise largely from the countries being able to import low-cost energy from large, regional-scale hydropower plants on the Congo, Zambezi and Rufiji Rivers[4]. Since 2001, SAPP has offered regional markets which allow trading of electricity over different time horizons, this being analogous to the market development envisaged for Nigeria in the 2023 Electricity Act.

By accessing the regional interconnected grid, the member countries of SAPP can derive several advantages:

Within the electricity sector

- Technical benefits – frequency stability, security of supply through shared reserves.
- Planning benefits – greater flexibility in developing generation projects, ability to develop larger plants to take advantage of economies of scale (very significant in the electricity sector).
- Reduced investment and operational costs of meeting demand.
- Improved utility viability.
- Accelerated attainment of electrification targets including the universal access targets in Goal 7 of the Sustainable Development Goals (SDG).
- Better and higher utilisation of variable RES sources – spread across a larger area RES are able to be utilised more effectively as the sum of their generation at any given time is less volatile, a larger pool of reserves on the system can compensate for low generation periods, and variable renewable energy (VRE) is developed in areas the resource is most abundant.
- Climate change benefits: CO_2 reductions and enhanced climate resilience with attendant co-benefits for the most vulnerable Nigerians.

Within the wider economy

- Resources freed up for investment in the productive sectors.
- More competitive industries and improved access for previously left - behind' Nigerians due to lower tariffs.

[4] The Pool Plan savings accrue despite the application of the so-called 'Security criterion' which requires the minimum level of generation capacity for each member to be equal to or greater than 100% of National maximum demand. To access the Pool Plan benefits countries must be willing to import lower cost energy even though this may mean domestic power plants operating at low-capacity factors. A big lesson from the Pool Plan is that relatively small transmission investments in regional interconnectors unlock significant savings in generation investment costs

- Electrification (especially on-grid) gives multi-fold benefits at the household level, including productive energy uses which also feed into the macro-economy.
- Higher employment and National income.

Once the National TCN grid has adequate capacity to transfer power across the country and is operating satisfactorily, all the above advantages are available to the States in Nigeria when they commit to the National grid. The prior challenge for TCN is to rapidly expand transmission capacity and improve the operation of the transmission network so that Nigeria soon has a reliable National grid.

2.4 Formulation of the NIRP scenario

An IRP 'scenario' is a set of assumptions that is used for a run of the IRP least cost model. The bedrock of the scenario is the demand forecast, with additional assumptions and constraints covering exogenous parameters such as future fuel prices, as well as endogenous, policy-driven variables, such as the pace of electrification. 'Sensitivity' analyses are conducted to examine the effect of specific variables of interest on a given scenario. For example, a scenario may identify a high penetration of RES as being the most cost-effective (least cost) solution by a certain date, but the sensitivity analysis may reveal that this conclusion is heavily dependent on assumptions on falling costs of RES technologies.

The choice of scenarios for the Nigeria IRP has been stakeholder-driven with the first formal discussion being in the Working Group workshop held in Abuja in September 2023. The key policy variables were identified at that workshop and carried forward to the preliminary elaboration of scenario options and subsequent detailed analysis of three main scenarios and four sensitivities.

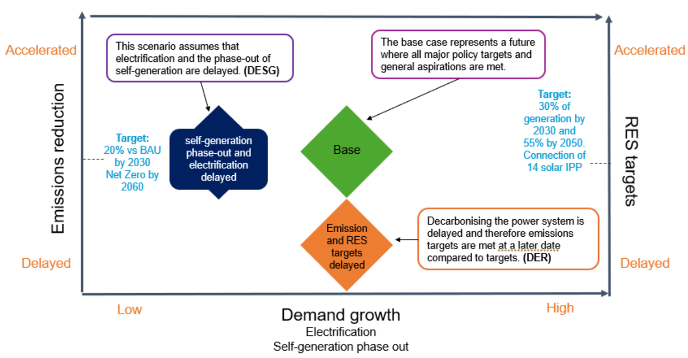
The next step was to select a scenario for the final Nigeria IRP and to carry out stress tests to ensure that the NIRP is robust and adaptable in the face of future risks and uncertainties. The criteria for choosing the NIRP scenario were:

- Demand forecast that is considered most reasonable for planning purposes (low, base and high demand forecasts were available from previous work).
- Incorporation of National policies on electrification, self-generation phase-out, renewables penetration and emissions reductions.
- Setting of targets for the policy variables that are challenging but attainable.

The scenarios that were examined in detail are mapped in the diagram below. The scenario bedrock, the demand forecast, is along the horizontal axis, while the vertical axis on the left has emissions reductions (the ETP targets being 20% reduction from business as usual by 2030 and net zero by 2060) and renewable energy targets on the right (targets of 30% renewables in the energy mix by 2030, 55% by 2050 and connection of the 14 pending solar independent power producers (IPP) projects). The additional policy variables are the achievement of universal electrification and the phasing out of self-generation in areas which should be served by the National grid. Both are targeted for 2030, with a delay to 2035 being examined in one of the scenarios.

In the **Base scenario**, which uses the base demand forecast, all the policy targets are met. There are two scenarios where the policy targets are delayed. In the **Delayed emissions and RES targets scenario (DRE)** the demand forecast is the same as the Base Scenario, while in the **Delayed electrification and self-generation phase-out scenario (DESG)** these policy targets are achieved in 2035 rather than 2030. From a modelling viewpoint, these delays mean that demand to be met by the grid is lower and hence this scenario is positioned to the left of the other scenarios.

Figure 3: Positioning of scenarios in the spectrum of demand and policy variables



Source: IRP Technical team

Self-generation currently accounts for roughly half of the supply to consumers who should be provided with grid electricity. The cost of self-generation is roughly three times higher than the grid and emissions are five times higher. As a result, delaying the phase-out from 2030 to 2035 would result in $29 bn of additional costs and an additional 90 mtCO2eq of emissions[5]. Replacing self-generation with access to reliable grid electricity will be a major boost to investment, economic growth and enhanced standards of living.

The phasing out of self-generation is thus a national imperative, but the consensus from the discussions is that the 2030 target is unattainable and it would be prudent to plan for the transition to have taken place by 2035. Similar concerns are raised about the target date for the achievement of universal access, 2035 being considered still challenging but much more likely to be attained than 2030.

The DESG scenario thus became the basis for the NIRP. This scenario adopts the base demand projection and produces least cost results which meet the RES penetration and ETP emissions targets. In anticipation of DESG being the preferred scenario, the four sensitivities conducted previously were relative to the DESG scenario rather than the Base Scenario, and the BESS with negative emissions sensitivity reduced the DESG costs.

Hence for the NIRP scenario a modification of the DESG scenario that has BECCS with negative emissions as a candidate option was adopted. The next two sections provide a systematic presentation and elaboration of the NIRP scenario, including drawing insights from the earlier analysis and reporting on the results of two further sensitivities (replacing base demand with the low demand projection and assuming curtailment of hydrological flows affecting hydropower potential).

[5] See Final Scenario Option and Least Cost Plan Report (M9), Section 6.2.

3

Criticality of Network Development

3

3.1 Situation of the Nigerian Electricity Supply Market

The importance of network development in Nigeria cannot be overstated and was one of the main points of discussion during the Draft NIRP review workshop held on 7 November 2024. From a power sector perspective, it is the first and most critical investment that needs to be addressed. As described in Section 1, currently, only about half of existing grid generation capacity is utilised due to transmission network limitations, meaning that supply is often interrupted and substituted by more expensive and polluting self-generation. Concurrently, a large proportion of the population remains without, or with limited access to electricity. A healthy and robust grid will provide the backbone to allow for Nigerians to benefit from an uninterrupted supply of electricity and maximise the utilisation of its abundant resources for generation, especially the renewable hydro and solar sources.

Examples in many regions around the world with a high rate of growth in generation and especially RES generation are relying increasingly on network expansion and interconnection with neighbouring regions as the most cost-effective way of meeting increasing demand. As was discussed in the Draft NIRP (M11) workshop by TCN and other Working Group members, having a national grid that is larger makes it more resilient as there is increased ability to share resources.

This is not a conclusion drawn only in Nigeria, but one that is experienced globally. The SAPP example mentioned in Section 2.3 shows the significant savings achieved through wider interconnection as opposed to relying on regional generation only. In Europe, European Network of Transmission System Operators for Electricity (ENTSO-e) has set an interconnection target of at least 15% by 2030 to encourage EU countries to interconnect their installed electricity production capacity. This is seen as fundamental to achieving Europe's climate and energy goals and to advance its security of electricity supply and to integrate more renewables.[6]

In Great Britain (GB), the need for network reinforcement to accommodate larger shares of renewables and growing demand was acted upon by Office of Gas and Electricity Markets (Ofgem) the regulator, which expedited transmission network investment under the Accelerated Strategic Transmission Incentive in December 2022, which involved ringfencing and fast tracking 26 strategic network investment projects totalling £20 bn (US$25 bn). More recently National Grid's Beyond 2030 report was released, with a £58 bn (US$73 bn) plan to upgrade the GB network to facilitate clean assets and renewable energy sources.

In the case of Nigeria, the focus in the short term will be to ensure that the ongoing transmission projects are completed successfully in a timely manner (see Section 4.3 for NIRP transmission assumptions), making possible

[6] European Commission, ENTSOe Electricity interconnection targets

the phase-out of self-generation as customers move to more efficient and cheaper grid supplied electricity. This will also allow the successful integration of RES projects, for example the Solar IPP projects (with PPAs) that have so far not been progressed due to grid operability limitations.[7]

This first publication of the NIRP makes an initial attempt at capturing some of the regional differences in resources and the network development that will be required between them by modelling the four zones described in Section 4.2. At the same time, the ongoing transmission projects are assumed to be finalised at the early stages of the modelling horizon and are not shown as an additional cost. As a first step, and until the NIRP can be aligned with the Transmission Master Plan currently being developed by TCN, it provides useful insights on the cross-regional developments that are least cost. However, this only partially captures and therefore underestimates the full requirements for network development.

Future iterations of the NIRP, when aligned with TCN's Transmission Master Plan[8], will be able to capture the real extent of network development requirements at a transmission level beyond the four zones of this NIRP but also within them. Network development needs to happen in tandem with generation development to achieve least cost development. If network development, which requires only a portion of the financial resources that generation requires, is delayed the result is underutilised or curtailed (in the case of RES) generation assets, as can be seen in Nigeria and the GB example mentioned earlier. Furthermore, distribution network development will also play a significant role in enabling the successful electrification of Nigeria and will have to be planned at a distribution level in conjunction with the National transmission and generation expansion plans.

The NIRP is a high-level planning instrument: the detailed individual investment projects are to be fleshed out through feasibility studies and at a regional level through the interaction of the NIRP with the SIP, as described in Section 2.1. In addition, the build-out of transmission lines is not enough because a network development plan must ensure that the grid can operate within operational limits. This will include the importance of wider investments in the grid such as reactive compensation and protection schemes, mentioned by TCN during the 7 November 2024 workshop. These will be captured in TCN's Transmission Master Plan and in the future through the more holistic role the Independent System Operator (ISO) will adopt.

[7] In 2016, Nigeria signed PPAs with 14 IPPs to build 1,125 MW of solar capacity for the National grid

[8] Due in 2025

4

Model results for the NIRP scenario with transmission

4

4.1 Introduction to NIRP modelling

As mentioned in Section 1, the original intention that transmission planning would take place in parallel with generation planning did not prove possible due to a delay in the start of work on TCN's Transmission Master Plan. The first least costs analysis that was done did not consider transmission at all. This work nonetheless provides useful insights on the direction in which the Nigeria power sector needs to move to meet projected growth in demand while at the same time meeting renewable energy and emissions targets. However, the absence of transmission was a major constraint, and the current version of the NIRP seeks to partially bridge the gap between generation-only planning results and a fully articulated NIRP which (during 2025) will be the result of an iterative process of generation and transmission planning that converges on the overall least cost solution.

Only limited transmission planning data was available for this version of the NIRP, and it must be emphasised that the model described here is a simplified generation-transmission model that has been developed to provide indicative results that indicate what the consequences are of considering the location of demand centres and generation sources. It is a simplified four zone representation of the Nigerian power system.

With the introduction of transmission, the computational complexity increases exponentially and even with only four zones to achieve the feasible running time for the model the level of granularity and flexibility in finding the least cost solution has had to be altered. The earlier generation-only results clearly showed that the 2060 net zero target has consequences in the least cost investment sequence for the choice of investments in earlier decades and hence it is important to run the model to 2060. However, with the simplifications just mentioned, the results at the end of the planning period may have some inconsistencies, and this NIRP presents results to 2045.

4.2 Key NIRP model assumptions

Regional split

To incorporate transmission considerations into the NIRP, a regional model with four nodes was developed by splitting Nigeria's power system into four zones. Using the franchise areas of the 11 existing Distribution Companies (Disco) in Nigeria as a starting point, four zones have been formed by the grouping of adjacent Discos. The zonal split is elaborated in Table 1 and the map in Figure 4 below.

Dividing Nigeria into four zones is an appropriate level of regional representation to assess transmission line build-out between generation and demand centres. This requires compact regions consisting of grouped demand centres and generation centres, especially where significant resources have specific locations. For example, there is greater solar potential in zone 2 due to the higher levels of radiations the area receives and greater hydro

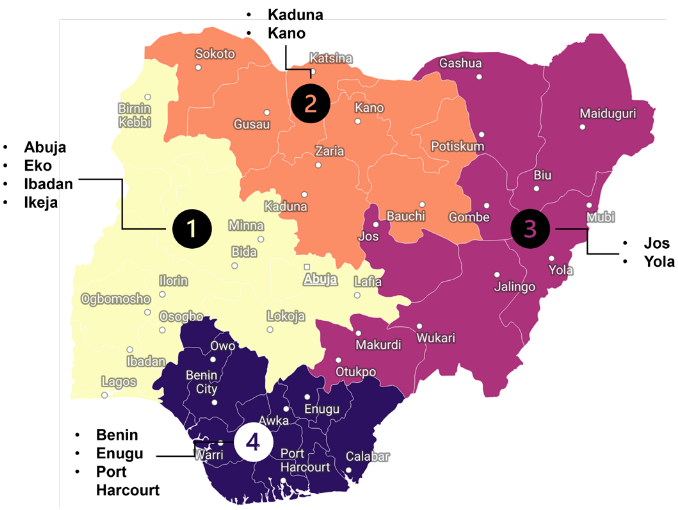
potential in zone 3, where many the identified potential hydro sites are located. The four-region model allows for a high-level assessment of least cost transmission requirements between regions, and more importantly, shows where bottlenecks on the networks are likely to be.

Table 1: Transmission model zonal split

Zone	Number of Discos covered
Zone 1	4 (Abuja, Eko, Ibadan, Ikeja)
Zone 2	2 (Kaduna, Kano)
Zone 3	2 (Jos, Yola)
Zone 4	3 (Benin, Enugu, Port Harcourt)
Total	**11**

Source: NIRP Technical team

Figure 4: Transmission model zonal split



Source: NIRP Technical team using Datawrapper

Demand profiles

Zone specific demand profiles were developed for each zone in the modelling setup. The earlier Demand Forecast Report provided the total on-grid demand at a national level. After excluding the element that is currently met by self-generation, the remainder was divided amongst the 11 Discos. The zonal demand is the sum of the demand of all Discos that belong to a certain zone. To exclude self-generation, it was assumed that self-generation makes up 49% of total on-grid demand in 2024, with this percentage decreasing linearly to reach 0% in 2035.

This is consistent with the adoption of the DESG scenario as the basis for the NIRP scenario, with National level on-grid demand being calculated under the assumption that universal access to electricity and self-generation phase-out will be achieved by 2035. To derive the Disco-level DESG demand from National level DESG demand up to 2035, the current electrification rate of each Disco as of 2024 was taken as the basis with linear growth being calculated to reach 100% by 2035. Using the growth factors implied by the increase in electrification rate, annual demand for each Disco between 2024 to 2035 was projected using their current demand as a starting point, as well as their percentage shares of the total National on-grid demand.

Given electrification is assumed to be 100% from 2035 onwards, the demand share of each Disco will also remain constant between 2035 and 2045. The percentage share of each Disco is then multiplied by the total National level on-grid demand for the entire modelling horizon of 2024-2045, giving the Disco demand which can be summed up by zones. Due to the lack of Disco specific data on electrification growth and self-generation share, variations across the four zones could not be considered. Both the rates of electrification and self-generation phase-out will differ across Discos and future NIRP work should start with separate demand forecasts for each region. Table 2 below summarises the zonal energy demand allocations.

Table 2: Zonal demand allocation

	2025	2030	2035	2040	2045
Total on-grid demand (GWh) (including self-generation)	**62,000**	**100,000**	**160,000**	**210,000**	**300,000**
Total on-grid demand (GWh) (excluding self-generation)	**35,000**	**78,000**	**160,000**	**210,000**	**300,000**
Demand share					
Zone 1	50%	45%	42%	42%	42%
Zone 2	15%	19%	22%	22%	22%
Zone 3	10%	13%	16%	16%	16%
Zone 4	25%	22%	20%	20%	20%

Source: NIRP Technical team

Existing transmission lines

Using data from the Working Group regarding existing transmission lines between adjacent Discos, the transmission lines between the four zones have been mapped. See data in Table 3 below.

Table 3: Exisiting transmission lines

Adjacent zones	Number of existing lines	Operational capacity per line (MW)	Total operational capacity (MW)
Zone 1 ↔ Zone 2	4	330	1,321
Zone 1 ↔ Zone 3	4		1,321
Zone 1 ↔ Zone 4	17		5,616
Zone 2 ↔ Zone 3	3		991
Zone 3 ↔ Zone 4	2		660
Total	**28**		**9,910**

Source: NIRP Technical team based on information received from the Working Group

The per line operational capacity for all existing lines identified is indicated to be 330 MW[9]. This value has been adopted as the maximum capacity of existing transmission between zones.

Candidate transmission lines

With regards to candidate transmission networks between zones, it is assumed that all adjacent zones will be interconnected by 330 kV single circuit (SC) networks. For zones with existing network connections, this means additional networks may be constructed to allow for future expansions in capacity, and for zones 3 to zone 4, which do not have any existing network connection, transmission networks will be added.

To calculate the build cost of candidate transmission networks, data on the distance between Discos and per kilometre unit costs are required. Using network unit cost data received from TCN, which includes a range of benchmarks data[10], the average of the different unit costs reported for 330 kV SC line were assumed for modelling purposes. In the absence of any distance data received and to avoid the introduction of artificial priorities, an approximate distance of 200 km between adjacent zones has been assumed. Moreover, between each pair of adjacent zones, a maximum network capacity of 5,000 MW is allowed to be built. The assumptions made regarding the build costs candidate transmission lines are given in Table 4 below.

[9] Operational transfer capacity limited to 50% as per current operational practices - provided by TCN in MW for 330kV lines

[10] TCN has provided unit costs data from recent procurements Fichtner mast plan 2018 estimation, JICA masterplan 2019 estimation, interNational benchmark from Tanzania case stud and interNational benchmark from Bangladesh case study.

Table 4: Candidate transmission lines

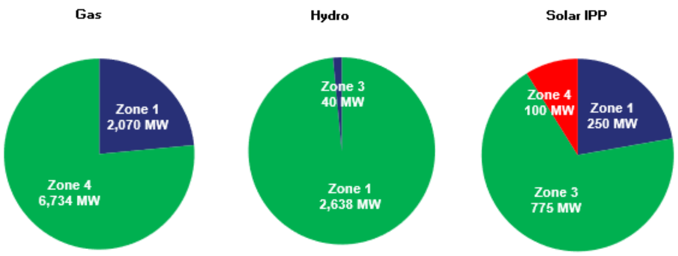
Adjacent zones	Unit Distance (km)	Unit cost ('000 USD/km)	Total network build cost (million USD)	Unit capacity (MW)	Maximum capacity allowed (MW)
Zone 1 ↔ Zone 2	200a	323	323 [b]	330	5,616
Zone 1 ↔ Zone 3					
Zone 1 ↔ Zone 4					
Zone 2 ↔ Zone 3					
Zone 3 ↔ Zone 4					

Source: NIRP Technical team based on information received from TCN
a. Unit distance refers to the distance between each pair of adjacent zones
b. Total network build cost is calculated using total distance multiplied by unit cost:
(200 ×5 (adjacent pairs)×USD 323,172 =USD 323,172,000)

Existing, committed and candidate generation options

Existing and committed generation options include 21 gas plants, five hydro plants and 14 solar IPPs, which have been tagged to the zones they are located in. A summary of the distribution of existing and committed resources across the four zones is shown in the Figure 5 below.

Figure 5: Existing and committed generation options



Source: NIRP Technical team

With respect to candidate generation options, the resources and technologies taken forward for the generation least cost analysis are summarised in Table 5 below, which also gives the approach and assumptions adopted to allocate candidate resources into the different zones. The full table containing the maximum capacity allowed per zone per technology is provided in Annex E.

Table 5: Candidate generation options

Technology	Allocation principle
Gas	Based on the gas pipeline projects identified, as detailed in Final Scenario Options and Least Cost Plan (M9) Report, Annex B, Table 26, and the zones they serve.
Gas + CCS	Limited to zone 4 where oil fields are located.
Hydropower	Site specific candidate hydro plants are allocated to the zones they are located in. For generic hydro plants, a Nigeria total allowed maximum capacity of 15 GW is allocated to each zone using percentage share factors. The percentage share factors are derived using a list from JICA (2019) containing 24 identified potential hydro sites, where the share of sites in each zone is used as a proxy for the share of hydro potential.
Solar PV	A Nigeria total allowed maximum capacity of 250 GW is allocated to each zone based on solar radiation distribution (kWh/kWp) data by Global Solar Atlas.
Solar CSP	A Nigeria total allowed maximum capacity of 89 GW is allocated to each zone based on solar radiation distribution (kWh/kWp) data by Global Solar Atlas.
Wind	A Nigeria total allowed maximum capacity of 3.2 GW is allocated to each zone based on wind intensity distribution (kWh/kWp) data by Global Wind Atlas.
Nuclear	Limited to zone 1 (Abuja and Ibadan regions), which cover the most economically developed regions.
Nuclear SMR	Due to limited data and information, the generic assumption of allowing for the same generation capacity across four zones has been made.
Biomass	Due to limited data and information, the generic assumption of allowing for the same generation capacity for zone, 2, 3 and 4 has been made. Zone 1 has been allocated a slightly lower capacity due to the small area of some of the Discos it contains.
BECCS	Due to limited data and information, the generic assumption of allowing for the same generation capacity for zone, 2, 3 and 4 has been made. Zone 1 has been allocated a slightly lower capacity due to the small area of some of the Discos it contains.
Hydrogen	Limited to zone 4 which has high levels of organic crops production activities in Nigeria and where oil fields are located.
	Due to limited data and information, the generic assumption of allowing for the same generation capacity across four zones has been made.

Sources: Inputs received from the Working Group, with research and assumptions made by the NIRP technical team

4.3 The NIRP Scenario

National-level results of the NIRP scenario

The National level results of the NIRP scenario are given in the table below. With the RES capacity share at 37% in 2030, the National renewable energy target of 30% by 2030 is easily exceeded. This shows that more renewable generation is least cost.

Table 6: Summary of results – NIRP scenario

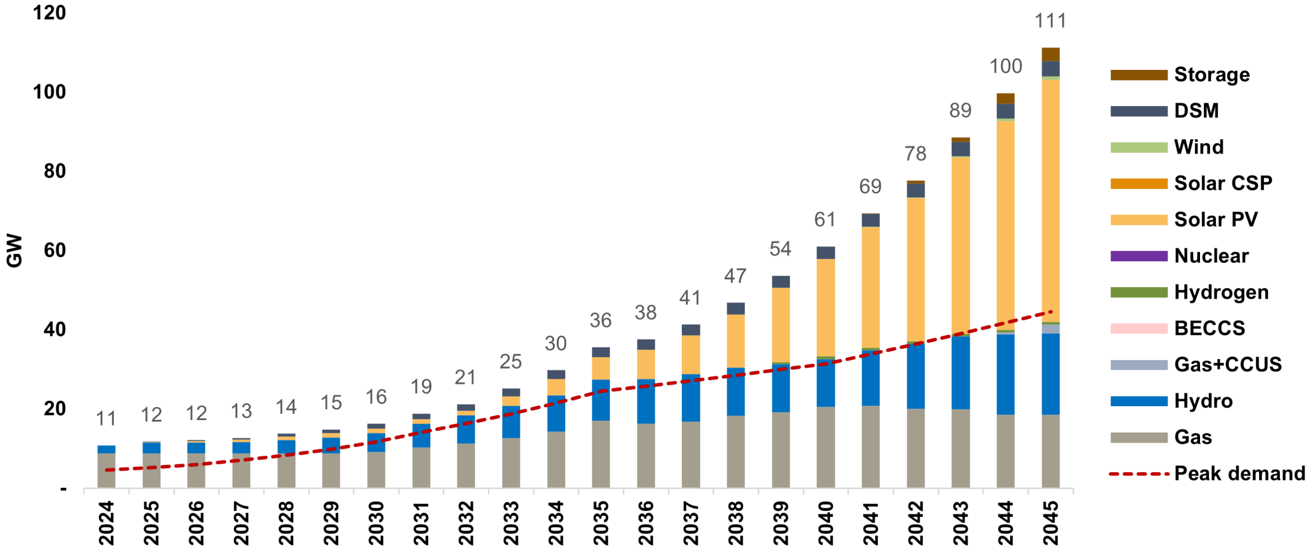
	Unit	2024	2030	2040	2045
Peak demand	*GW*	5	12	31	45
Installed capacity (incl. storage)	*GW*	11	16	61	111
RES capacity	*GW*	2	6	37	83
Storage capacity (incl. solar CSP storage)	*GW*	-	-	-	3
Storage energy capacity (incl. solar CSP storage)	*GWh*	-	-	-	11
Average storage duration	*hrs*	-	-	-	3
RES capacity	*% of total*	18%	37%	61%	75%
Energy demand	*TWh*	30	78	209	301
Storage demand	*TWh*	-	-	-	4
Generation	*TWh*	31	86	220	308
Share of RES	*%*	29%	34%	54%	73%
Short run marginal costs	*$/MWh*	27.8	23.4	15.4	36.1
		2024-45	**Cost %**		
NPV of total costs	*bn$*	63	100%		
NPV of capex	*bn$*	40	63%		
NPV of transmission costs	*bn$*	0.3	0%		
NPV of fuel costs	*bn$*	9	14%		
NPV of variable O&M	*bn$*	7	11%		
NPV of fixed O&M	*bn$*	8	12%		
LCOE	*$/MWh*	49.3			
LCOE	*c$/kWh*	4.93			

Note: $ are USD in 2022 prices

Figure 6 and Figure 7 illustrate the installed capacity, peak demand and generation of energy up to 2045 per technology for the NIRP scenario. Up to 2030 installed capacity is primarily met by gas and hydro. From then onwards solar PV and BESS increase substantially by 2045 making up most of the installed capacity.

By 2045, 61 GW of solar PV and 3 GW of storage are on the system. Some Gas+CCUS is also built from 2044 onwards, reaching a total of 2.3 GW by 2045. Solar PV has low-capacity factors and hence to meet peak demand of 45 GW a total of 111 GW of capacity is on the system by 2045.

Figure 6: Installed capacity 2024-45 – NIRP scenario



Old gas plants are being retired towards the end of the period, but retiring firm capacity is replaced by Gas+CCUS so that gas overall still covers 27% of energy generation by 2045. The remaining demand is primarily met by solar PV, Hydro and DSM.

Figure 7: Generation 2024-45 – NIRP scenario

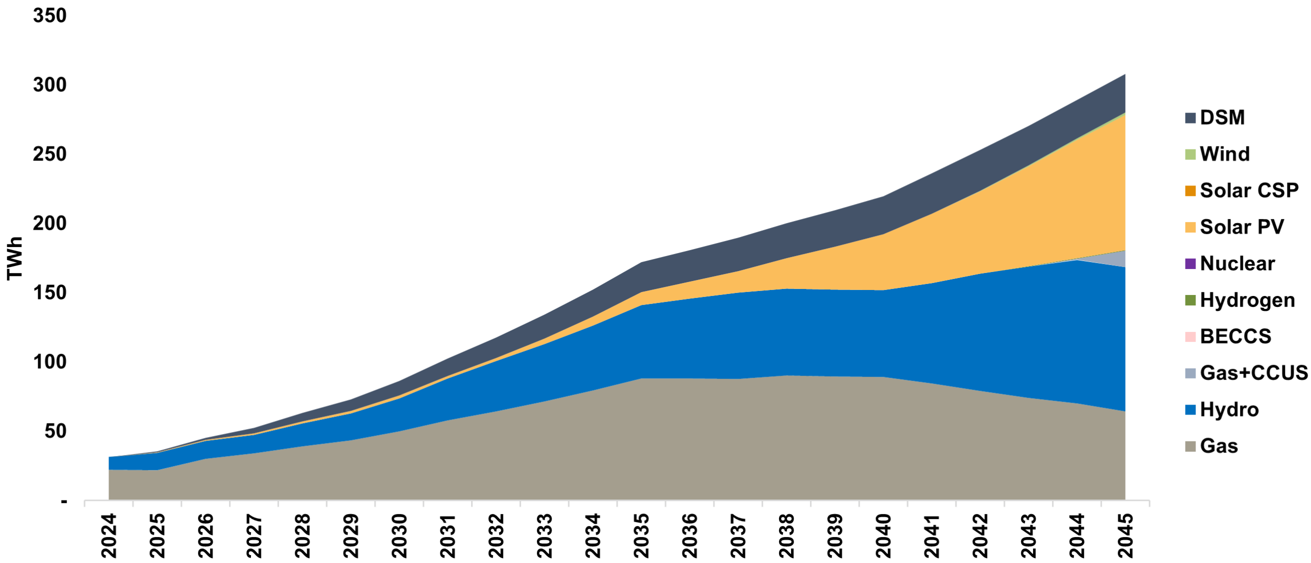


Figure 8 shows the growing need for storage on the system. Up to 2040 limited storage is required as there is a substantial level of firm capacity available. From then onwards storage requirements grow significantly to 3.4 GW in 2045. The duration of storage also increases with time as higher shares of intermittent renewables require larger storage duration capability with the average storage duration growing to 3 hours in 2045. In 2045, the first CSP plants are being installed – these offer 10-hour molten salt storage which is an effective way of extending the average duration when combined with battery storage systems. Detailed year by year results are provided in Annex F.

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Figure 8: Storage capacity and duration

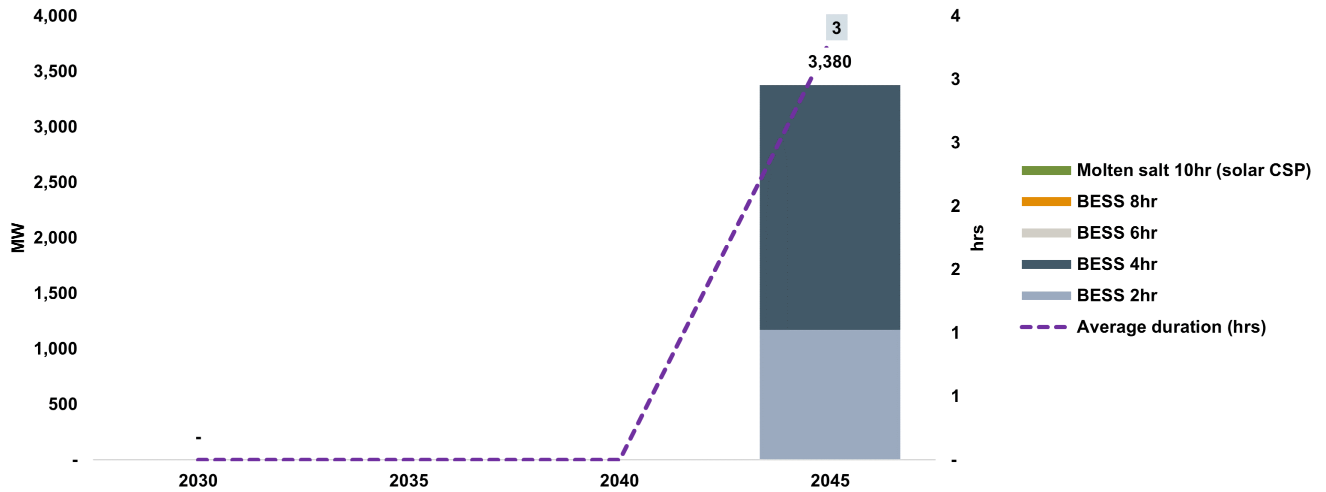


Table 7 and Table 8 provide **capacity additions and capacity factors**[11] in five-year intervals while year by year results for these parameters are provided in Annex F.

In 2030, demand is met mainly by gas and hydro which operate at 57%-62% capacity factors, with the remaining being met by solar PV. There are large increases in hydro and solar PV capacity from 2035 onwards. Gas has negative additions (retirement of old plant) in 2045 while emerging technologies such as Gas+CCUS, BECCS, hydrogen and nuclear remain at small or zero levels. In 2045, Gas+CCUS and Hydro have the highest levels of utilisation (capacity factors of 58%-60%).

Table 7: Capacity additions (GW) by technology – five-year intervals

(GW)	2025	2030	2035	2040	2045
Gas	-	0.3	8	3	-2
Hydro	1	2	6	2	8
Gas+CCUS	-	-	-	-	2
BECCS	-	-	-	-	-
Hydrogen	-	-	-	1	-
Nuclear	-	-	-	-	-
Solar PV	0.2	1	5	19	37
Solar CSP	-	-	-	-	-
Wind	-	-	-	-	1
DSM	0.1	1	1	1	1
Storage	-	-	-	-	3
Total	**1**	**5**	**19**	**25**	**50**

[11] Capacity factor is a measure of utilisation and derived by dividing actual generation by maximum generation possible (if operated at maximum capacity continuously).

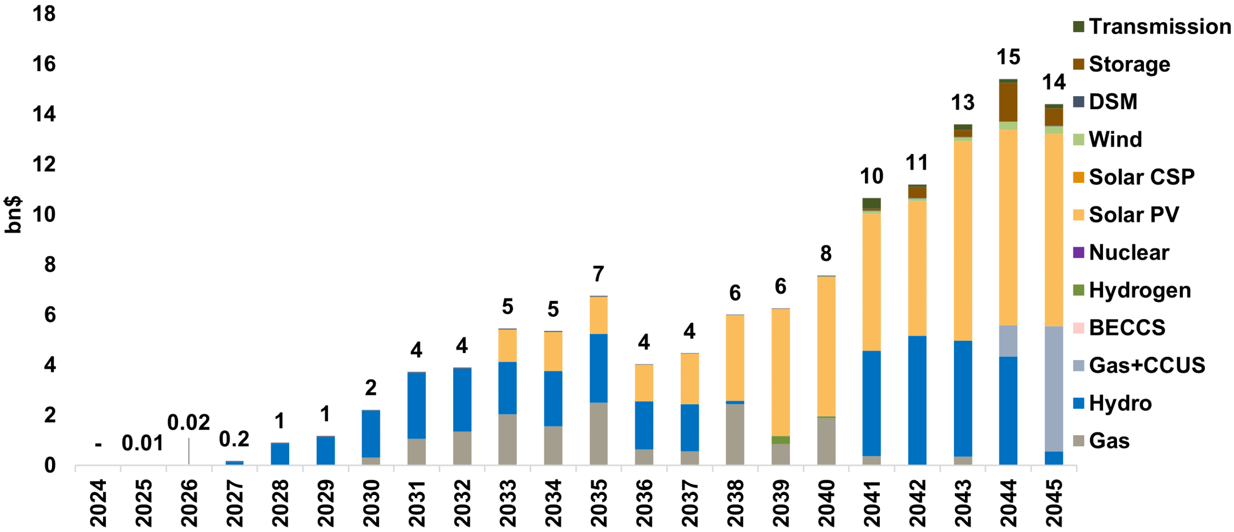
Table 8: Capacity factors by technology – five-year intervals

(%)	2025	2030	2035	2040	2045
Gas	29%	62%	59%	50%	40%
Hydro	39%	57%	59%	59%	58%
Gas+CCUS	-	-	-	-	60%
BECCS	-	-	-	-	-
Hydrogen	-	-	-	0.1%	6%
Nuclear	-	-	-	-	-
Solar PV	-	19%	19%	19%	18%
Solar CSP	-	-	-	-	-
Wind	-	-	-	-	24%

Figure 9 presents **annual investment costs**[12] required for the NIRP scenario to 2045. Investments pick up in the early years rising to $2 bn by 2030. From then onwards they stay within a range of $4 bn to $8 bn per year until 2040. Most of the investment is required in the later years, increasing to $14 bn-$15 bn in 2044 and 2045.

By 2045 a **total of $122 bn** will be required, of which the largest expenditure will be on solar PV at $56 bn, hydro at $39 bn, gas at $16 bn, Gas+CCUS at $6 bn, and storage at $3 bn. Detailed year by year results are provided in Annex F.

Figure 9: Investment costs 2024-45 – Draft NIRP (M11) scenario



[12] The investment costs refer to consist of build cost (capex), which are assumed to be incurred in the year in which the project is commissioned. In practice, investment costs for large projects are spread over several years. The details of financing arrangements are to be incorporated in the SIP.

The **transmission network investment costs** included in the model are minimal (~$1 bn), but this does not reflect the critical role of transmission which shapes the least cost generation investments in the different zones. The low levels of investment expenditure in the early years that is illustrated in the graph above is because there is excess generation capacity at the start of the planning period and because the extent of transmission network development required within each zone is not captured (see Section 3 for further information on the criticality of network development)[13]. The excess generation cannot meet demand because of a lack of transmission capacity. There will be substantial expenditures in those years on TCN's ongoing investment projects which are set to significantly increase transmission capacity on the National grid, and in addition distribution network investments. The NIRP model assumes that the transmission capacity increase will come on stream, but the expenditures on TCN's ongoing projects are not reflected in the graph above.

To put the costs of ongoing transmission line projects into context, indicative costs using data inputs from TCN and the Working Group have been made. Identifying 16 inter-zonal transmission lines that are labelled as 'under construction' and using approximate distances and unit cost data provided by TCN, indicative costs of these ongoing projects are summarised in the table below.

It has been assumed that these network costs, which total to $192 million, will be incurred over a five-year period between 2024 to 2028, which is when the projects will reach completion. Figure 10 below shows how these network costs compare with the candidate transmission network projects that will be built between 2040 to 2045 and costing a total of $1.1 billion. When compared to the generation investment costs as shown in Figure 9 above, both sets of transmission network costs are small so do not make a difference to the NPV of total costs. However, to repeat the point made above, **the small expenditures on transmission networks do not reflect the true scale and critical role that these investments have in shaping the overall least cost plan for the Nigerian power sector** and will be captured in more detail in the next iteration of the NIRP when TCN's Transmission Master Plan is developed.

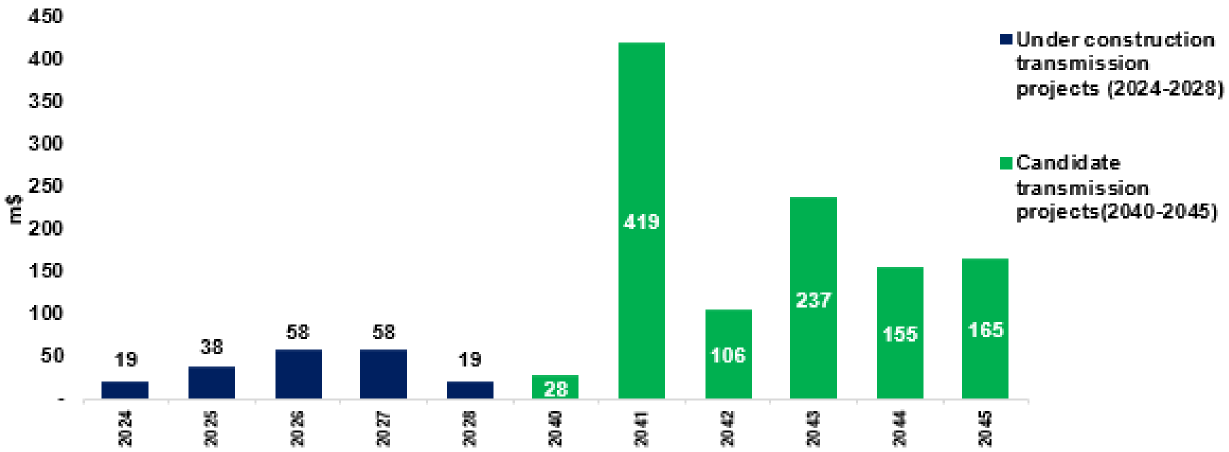
Table 9: Transmission Model Zonal Split

Zone	No. of lines under construction	Unit build cost (000' USD)	Indicative distance (km)	Total indicative costs (mil USD)
1 ↔ 2	2		160	52
1 ↔ 4	12	323	260	84
2 ↔ 3	2		175	57
Total	**16**			**192**

Source: NIRP Technical team

[13] A more holistic assessment of network development needs will be captured in the next iteration of the NIRP in conjunction with TCN's Transmission Master Plan currently under development and due in 2025.

Figure 10: Transmission costs



Zonal results of the Draft NIRP (M11) scenario

The installed capacity in 2045 of the different technologies in each zone is shown in Figure 11 below. The least cost solution includes some gas capacity in each region, but particularly in zone 1 and zone 4, where a significant portion of the thermal capacity by then is Gas+CCUS. By contrast, installed capacity in zones 2 and 3 is solar PV with associated storage. Hydro capacity is predominantly in zone 1 and zone 3.

Figure 11: Installed capacity (GW) by technology and zone in 2045

Energy generation by technology and zone in 2045 is illustrated in the bottom set of graphs. Reference source not found.. These graphs accentuate the picture of northern solar PV vs southern gas. The solar in zone 3 is complemented by hydropower, while in zone 2 the solar PV is matched by gas and energy from storage, plus a range of other technologies. The other two zones have some energy from solar PV but rely more heavily on gas and hydro (zone 1) and Gas+CCUS (zone 4).

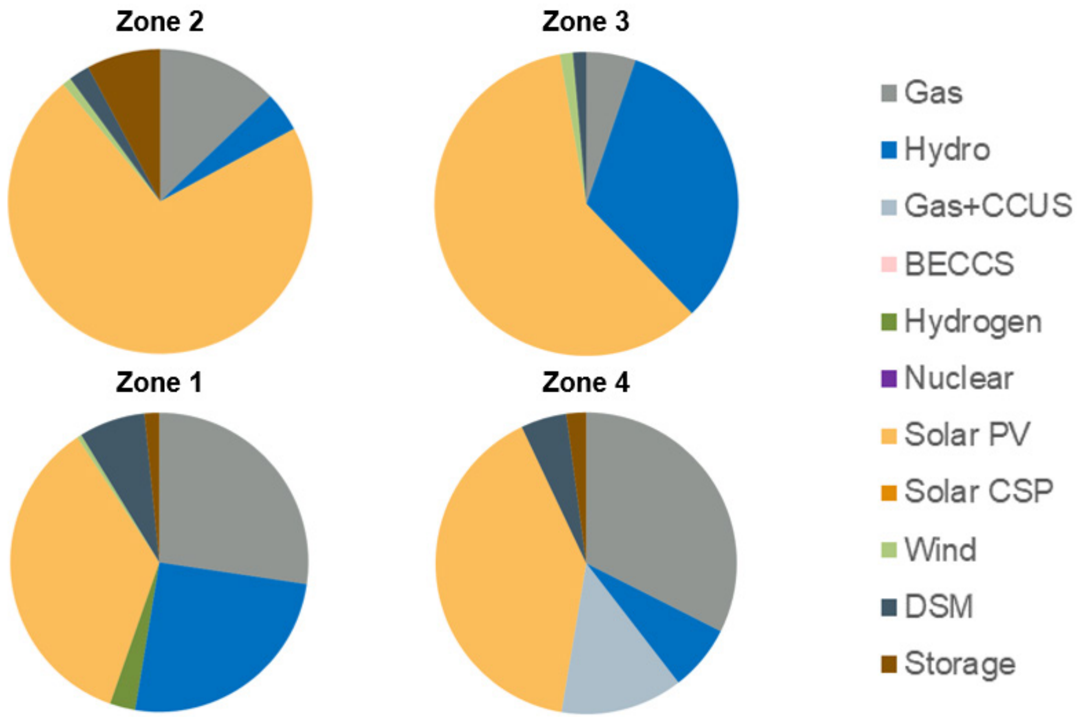
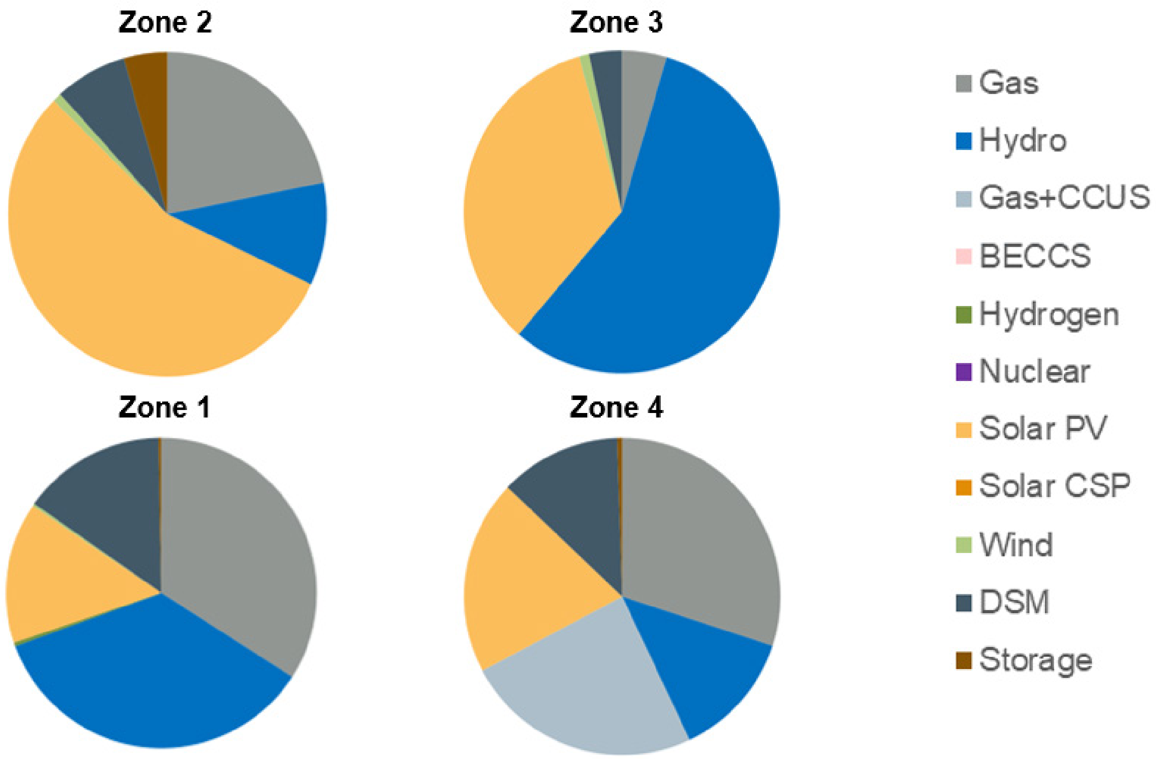


Figure 12: Energy generation (TWh) by technology and zone in 2045



To make best use of the different types of generation in the different zones, optimal operation of the National power system requires strong north-south transmission interconnectors. This stands in contrast to the emphasis in the current transmission investments which are more focussed on east-west inter-zonal connectors. The data on existing transmission lines indicates that currently there are ten transmission lines connecting the northern and southern zones[14] while 20 connect the eastern and western zones.

As shown in the figure below, in the earlier years leading to 2030, both installed capacity and energy generation[15] are concentrated in zone 1 and zone 4, which have significant shares of hydro and gas respectively. By 2045, however, zone 3 takes the lead in terms of capacity installed and energy generated and when combined with zone 2, the northern regions' capacity and generation exceed those of the southern regions, making transmission infrastructure and capacity crucial for achieving least cost operations.

Figure 13: Installed capacity (GW) by zone in 2030 and 2045

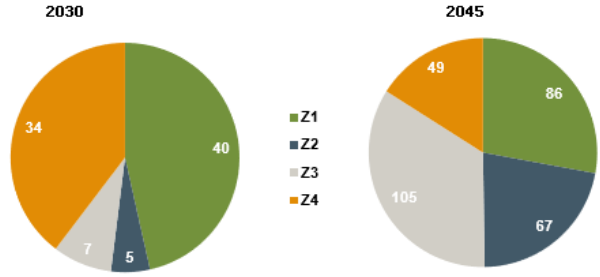
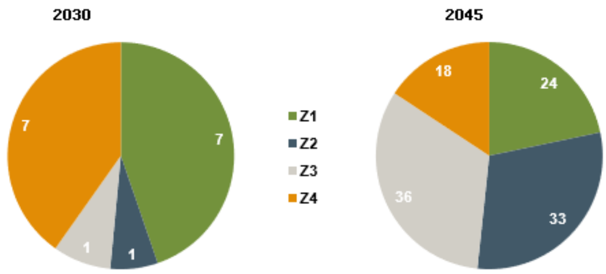


Figure 14: Energy generation (TWh) by zone in 2030 and 2045



[14] Zone 1 to 2, 1 to 3 and 3 to 4
[15] Excluding storage

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It was noted earlier in this section that the total investment requirement over 2024-2045 is $122 bn. The zonal breakdown of this requirement is shown in Table 10 below. The investments are relatively evenly spread across the zones, but with higher investments in zones 2 and 3 where the bulk of the solar PV and hydro projects are to be undertaken due to its resource potentials. Zone 2 has expenditures in solar CSP and storage while zone 3 has a high level of investment in hydro. In the southern region, the biggest investments are in Gas+CCUS in zone 4.

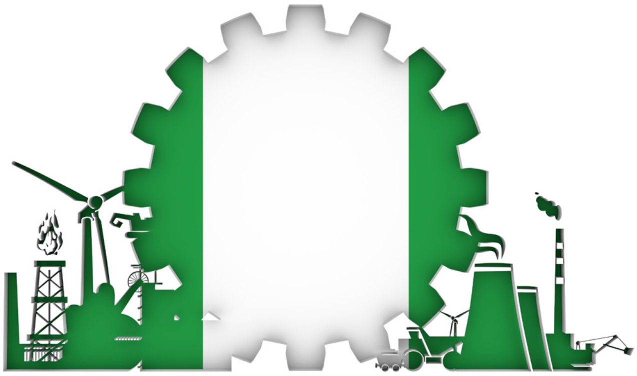

Table 10: Investment costs 2024-2045 by technology and zone (bn$)

bn$	Zone 1	Zone 2	Zone 3	Zone 4	Total	%
Gas	6	4	2	5	16	*13%*
Hydro	7	3	26	3	39	*32%*
Gas+CCUS	-	-	-	6	6	*5%*
BECCS	-	-	-	-	-	-
Hydrogen	0.4	-	-	-	0.4	-
Nuclear	-	-	-	-	-	-
Solar PV	8	22	19	7	56	*46%*
Solar CSP	-	-	-	-	-	-
Wind	0.1	0.3	1	-	1	*1%*
DSM	0.2	0.1	0.1	0.1	0.1	*0%*
Storage	0.3	3	-	0.2	3	*2%*
Total	**22**	**32**	**47**	**20**	**122**	
%	*18%*	*27%*	*39%*	*17%*		

4.4 Sensitivities

Four sensitivities on the DESG scenario were conducted at the generation-only stage. These did not need to be repeated for the model that includes transmission because the impact on the NIRP results can readily be deduced from the previous work:

- ***downside sensitivity:*** higher fuel prices were not found to have a large impact on the overall results because of the limited role of gas, with this declining significantly towards the net zero year (2060). In the context of the zonal model, higher gas prices have differential impacts with zone 1 and 4 being much more severely affected than the solar-dominated zone 2 and 3.
- ***upside sensitivity:*** reductions in the capital costs of RES and BESS technologies were found to have a significant beneficial impact, giving scope for higher levels of renewables investments and reduced expenditure on fuel. In the zonal model, the impact is again differential, with zone 2 and 3 which have the best solar resources benefitting more than zone 1 and 4.

The other two sensitivities were more technical in nature: BECCS with negative emissions being offered as a candidate to allow more flexibility as net zero is approached and a higher social rate of discount. The generation-only model anticipates the strict 2060 net zero requirements by installing more hydro in the BECCS scenario and this gives a lower LCOE in 2045 as well as 2060. It is for this reason (as mentioned in Section 4.1) that BECCS with negative emissions has been included as candidates for the NIRP scenario, but it is to be noted that up to 2045 BECCS is not selected as part of the least cost solution by the model.

The additional sensitivities that have been carried out for the NIRP are:

- ***low demand:*** replacing the base case demand forecast, which had an energy growth rate of 7.7% per year up to 2045 (328.6 TWh), with the low demand projection (annual average growth rate of 5.9%, reaching 221.8 TWh in 2045).
- ***reduced water availability for hydro:*** the impact of possible future reductions in the availability of water for hydropower generation, due to climate change or other factors, was tested by restricting capacity factors at hydro plants to half of their base values. This was also an indirect way of exploring the importance of hydropower in the NIRP plan.

The results are summarised in Table 11 below. The main driver of the investment sequence in an IRP is demand, so it is not surprising that the results are highly sensitive to the rate of growth of demand. As indicated in the table, while peak demand is one-third less than the base peak demand in 2045, installed capacity is 55% lower with total costs and LCOE lower by 41% and 23% respectively.

Table 11: Comparison of 2045 results of Draft NIRP (M11)scenario and sensitivities

	Units	NIRP	Low demand	Low hydro
Peak demand	*GW*	45	30	45
Installed capacity (incl. storage)	*GW*	111	50	137
RES capacity	*GW*	83	31	97
Storage capacity	*GW*	3	-	7
RES capacity	*%*	75%	63%	71%
NPV of total costs	*bn$*	63	37	82
LCOE	*$/MWh*	49.3	38.0	63.1
LCOE	*c$/kWh*	4.93	3.80	6.31
Emissions (excl. self-generation)	*mtCO2eq*	644	521	671

Note: $ are USD in 2022 prices

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The assumption of reduced water availability for hydro-generation has the effect of requiring additional capacity to be installed (23% higher by 2045) with total costs and LCOE higher by 30% and 28%, respectively. As Nigerian hydropower rivers are less prone to climate changed-induced drought than is the case in other countries in Sub-Saharan Africa, the results of the sensitivity test may alternatively be interpreted as illustrating how important hydropower is in the NIRP least cost solution.

4.5 Modelling Conclusions and Recommendations

As emphasised in Section 4.1, the NIRP scenario results presented in this document are to be treated as indicative. It will only be possible to produce a comprehensive NIRP when the generation and transmission planning can be iteratively coordinated to converge on the overall least cost solution. It is nonetheless the case that the modelling results obtained so far provide some important insights for IRP planning in Nigeria. The following summary points can be highlighted:

- **Demand:** growth in demand is the fundamental driver of the generation and transmission investment sequence. The results are highly sensitive to the demand forecast. The out-turn should be monitored, and the forecast continually updated so that appropriate adjustments can be made to the NIRP during implementation.
- **Electrification and Self-generation Policy Targets:** as discussed in this report, the 2030 target for the achievement universal electrification and the phasing out of self-generation are widely considered not to be feasible and hence the target year for these two objectives has been shifted in the NIRP analysis to 2035. Even this year will be very challenging and a concerted effort across a number of fronts will be needed if they are to be attained. As estimated previously in a parallel model a 5-year delay to 2035 will result in $29 bn of additional costs and an additional 90 mtCO2eq of emissions. Replacing self-generation with access to reliable grid electricity will be a major boost to investment, economic growth and enhanced standards of living.
- **Renewable Energy and Emissions Policy Targets:** National renewable energy and emissions reduction targets for 2030 and 2050 are readily absorbed into the NIRP but become very challenging close to the net zero target year of 2060. Planning ahead for net zero in 2060 has implications for least cost investments in earlier years such as 2045.
- **North and South:** the Draft NIRP (M11) modelling has confirmed that the northern part of Nigeria is set to become the country's solar energy powerhouse. Storage to firm the solar will become increasingly important, with a mix of battery storage and CSP molten salt storage being chosen as part of the least cost investment sequence. To 2045 the southern region will continue to rely on gas generation, though this will increasingly be combined with CCUS.
- **Hydropower** is an important component of the generation mix, covering 33% of the total energy generation in 2045, and all opportunities for developing hydropower (run-of-the-river as well as storage schemes) should be taken up. The sensitivity test on reduced hydrological flows emphasises the importance of hydropower in the least cost solution for the NIRP: curtailment of hydropower would necessarily require investments in more expensive technologies.
- **Transmission:** To make best use of the different types of generation in the different zones, optimal operation of the National power system requires strong north-south transmission interconnectors. This stands in contrast to the emphasis in the current transmission investments which are more focussed on east-west inter-zonal connectors. The importance of network development is critical and future iterations of the NIRP should capture a more complete view of network development requirements and their interrelation with generation expansion, in first instance when TCN's Transmission Master Plan is complete.
- **Flexibility:** in addition to the analysis underpinning an IRP relying on a multiplicity of data, there is a wide range of uncertainties that impinge on the implementation of an IRP. It is advantageous therefore to emphasise flexibility. The outcome of the NIRP can be improved by periodically updating the analysis on the basis of improved data and taking action when real world uncertainties are resolved (whether this be adversely, such as capital or fuel costs being higher than expected, or advantageously, such as more water than expected being available for hydro-generation). Good monitoring of the NIRP is needed – proposals on this are given in Section 6 below.

5

Stress Tests for the NIRP

5

It is crucial to recognise that there exists a range of uncertainties and issues in the real world that can impinge on the IRP, potentially compromising and in some cases enhancing the indicative NIRP least cost outcomes. The table below provides a summary of major risks and proposed mitigation approaches. A major aspect of the approach to mitigation is to have a robust structure in place for the implemtation of the IRP and the continuous monitoring of its impact. Proposals for the implementation and monitoring of the NIRP are provided in Section 6 below.

Table 12: Risks and mitigation approaches

Risk Factor	Key Risks	Mitigation Approach
Gas supplies are interrupted	Gas plants are not able to operate as envisaged in the model because gas is not available	Some curtailment of gas could be managed by using other plants at higher capacity levels, but severe and prolonged lack of gas that is not fixed by the gas sector would require higher electricity imports from West African Power Pool (WAPP) or additional investments in non-gas technologies, particularly peaking plant or BESS storage.
High gas prices	Gas prices turn out to be much higher than is assumed in the modelling	Sensitivity test has shown that due to limited future role of gas in the NIRP the impact of higher gas prices on overall electricity prices would be limited.
Water availability	Hydro plants are not able to operate as envisaged in the model because of water availability	Some curtailment of hydro could be managed in the early years by gas capacity, but hydro has shown itself to be the most important source of renewable energy generation in Nigeria and the lack of it would likely mean high level of generation from gas need to be maintained. To help meet the RE targets, investments in other higher cost technologies will also be needed. The results of the hydro sensitivity test in Section 4.4 are relevant here.
Realised demand	Risk of realised demand being significantly above or below the base case demand projection used in NIRP	The demand sensitivity test has shown the results are highly sensitive to the demand forecast. The out-turn should be monitored, and the forecast continually updated so that appropriate adjustments can be made to the NIRP during implementation.
Demand lower than the Base Scenario	Risk of over-investment, tying up capital in generation and transmission assets which are under utilised	Demand is to be monitored, and the pace of investment lowered if realised is systematically lower than forecast; attempts to be made to increase exports of electricity to WAPP.
Network development delays	Stranded generation assets that are under utilised	Ensure that network development is planned and implemented in tandem with generation expansion allowing for the full potential of the power system to be realised.
Demand higher than the Base Scenario	Risk of power system being over-extended, forcing load shedding and the high economic costs of unserved electricity demand	Demand is to be monitored, and the pace of investment increased if realised demand is systematically higher than the NIRP forecast; attempts to be made to increase imports of electricity from WAPP to meet shortfalls.

Capital availability and financing	Challenges associated with capital mobilisation and arranging risk coverage to reach financial closure may slow the pace of investment and resulting in unserved energy	Energy investments are large and there needs to be early planning for capital raising and financing of generation and transmission projects. Financing plans should also be carefully monitored to identify and deal with potential bottlenecks.
Environment and regulatory procedures	Ensuring compliance with environmental and regulatory requirements may involve extensive procedures and technical studies, delaying planned investments in technologies like hydro and nuclear	Environmental and regulatory considerations should be considered at the inception phase of any project investments, including details on any procedures that need to be fulfilled at different points in time. Environmental and regulatory experts should be involved in the discussions.
Security	Vandalism and lack of security on infrastructure development sites can cause delays in generation and transmission investment projects and interruptions in supply from already built infrastructure	Task forces should be put in place to ensure that the necessary security personnel and equipment are in place before the commencement of projects. Close working relationships with local authorities should be established through joint working groups.
Institutional barriers	Prolonged periods may be required for the enactment of enabling legislation for new practices, particularly with the case of emerging technologies (e.g., hydrogen, CCS, nuclear)	Ensure policy continuity at the Government level, including actions that need to be taken or authorities that need to be established to carry out the required forward planning.
Just Transition	Large scale generation and transmission infrastructure projects may harm certain vulnerable groups in society if not managed carefully	Environmental and socio-economic impacts should be fully explored during project feasibility studies and adjustments made if necessary to minimise adverse effects on communities. Working groups should be established to closely engage with vulnerable communities.
%	Large scale generation and transmission infrastructure projects may harm certain vulnerable groups in society if not managed carefully	Environmental and socio-economic impacts should be fully explored during project feasibility studies and adjustments made if necessary to minimise adverse effects on communities. Working groups should be established to closely engage with vulnerable communities.

Source: IRP Technical team

A vivid example of institutional and financing barriers delaying investments is the saga of the 14 Solar IPP projects (characterised in this report as committed projects). In 2016, the government signed power purchase agreements (PPAs) with 14 IPPs for the construction of about 1.12 GW of total installed grid-connected solar capacity. However, none of these plants have reached financial close due to several challenges, the main one being the provision of government guarantees to mitigate developers' risk. Discussions between the government and the IPPs on re-activating the PPAs have recently resumed, but no agreements have been announced.

6

Implementation of the NIRP

6

6.1 Institutional structure

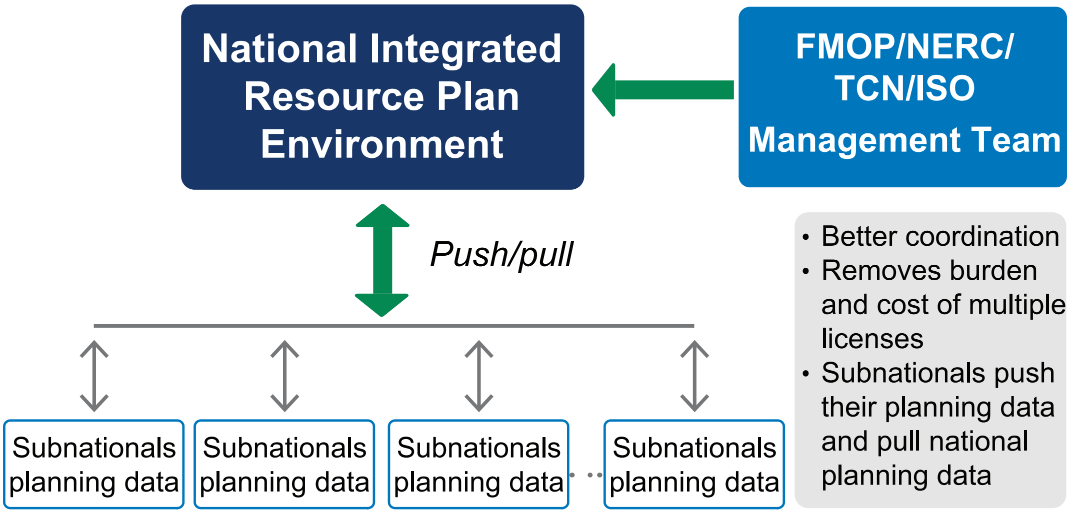
The nature of integrated resource planning is that it is a process, rather than an event marked by the publication of the NIRP document. To be effective, an IRP needs to be consistently implemented, carefully monitored and periodically updated. In Nigeria's case, there is the additional challenge that the NIRP needs also to be coordinated with the State IRPs which will always be at different stages of development and implementation. As laid out in Section 2.1, the initial NIRP investments are to be included in the Strategic Implementation Plan, which will be a short-term instrument updated on an annual basis to maintain the implementation momentum.

The proposal is that the NIRP process will initially be the responsibility of a joint FMoP / NERC / TCN-ISO Management Team. Subsequently the responsibility will be assumed by the ISO which is currently being established in conformity with the provisions of the 2023 Electricity Act. The relationship between National and sub-National planning is illustrated in the diagram below. As mentioned in Section 2.2, consistency between the plans is to be achieved through having a common software platform, the costs of which are to be met by NERC/ISO when the initial funding by- FCDO has been exhausted.

Effective **monitoring** of an IRP is important to ensure that the flexibility and adaptability that has been built into the plan at the design stage is realised. It is recommended that the SIP and the NIRP be monitored by a focussed **Power Planning Monitoring Committee (PPMC)** of mid-level officials drawn from FMoP, NERC, TCN, ISO, ECN and representatives of the States. When the ISO assumes responsibility for NIRP, the PPMC will be chaired by the ISO.

The PPMC will report to the NIRP Management Team and subsequently, when the ISO assumes responsibility for the NIRP, to the ISO.

Figure 15: Institutional structure for integrated resource planning in Nigeria



Source: NIRP Technical team

When the ISO is established and assumes responsibility of the NIRP, it is proposed that a **regulatory instrument will be implemented by NERC to ensure the NIRP remains a dynamic and live process** that gets updated periodically. This will be monitored by NERC as a requirement by the ISO. The details of this regulatory instrument are to be finalised in due course.

At points in the future where the NIRP is to be updated, the PPMC, working with the broader coalition of stakeholders represented on the current NIRP Working Group, would take the lead on this, but in the interim their role would be to monitor:

- **Demand:** the evolution of demand, and how this compares with the projections made at the planning stage.
- **Projects:** the implementation of generation and transmission projects, whether these are in line with the timing laid out in the NIRP or lie outside of the plan.
- **Technology:** how realised capex costs for different technologies compare with the assumed costs in the NIRP, what technological advances are materialising which would need to be captured in the candidate project list at the next iteration.

An **annual retreat** of the PPMC is recommended as this would provide the opportunity for the above three items to be explored in depth and a decision made on whether a fresh run of the least cost NIRP model is needed and/or whether a full-scale updating of the NIRP should be recommended to the NIRP Management Team.

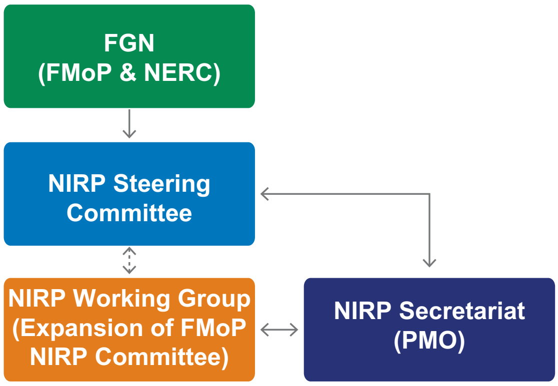
This model for monitoring an IRP has been successfully deployed in other African countries. The experience has been that the members of the PPMC do not just turn their attention to planning when the annual retreat is due, but instead become involved in continuous monitoring and exchanges with other committee members throughout the year. This helps to enhance job fulfilment and break down the barriers which exist in all countries between different agencies in the electricity sector.

6.2 The NIRP Programme Management Office

Executing the day-to-day undertakings of the NIRP along with the technical teams who engaged to support its preparation, implementation, and adaptation will be the task of the **NIRP Project management Office (PMO)**, established as an entity within the FMoP/NERC/TCN-ISO Management Team (at the first instance before the handover to the ISO when established). The capability and capacity of the PMO will be critical to the broader process of coordinating National and sub-National IRP as well as to the actual 'hands-on' undertaking of the NIRP process. The PMO is expected to be a permanent entity unless limited by law or regulation related to the NIRP.

The PMO will not be a decision-making entity and will have no authority to take decisions without prior approval. As illustrated in Figure 15 below, the PMO will take direction from the NIRP Working Group (primary) and will obtain approvals from the NIRP Steering Committee component of the Interministerial Power Sector Working Group. Members of the PMO are expected to primarily be drawn from FMoP, NERC, and TCN (ISO). Specifically, the functions of the PMO will span from the overall NIRP process coordination and least cost modelling to stakeholder engagement and capacity building.

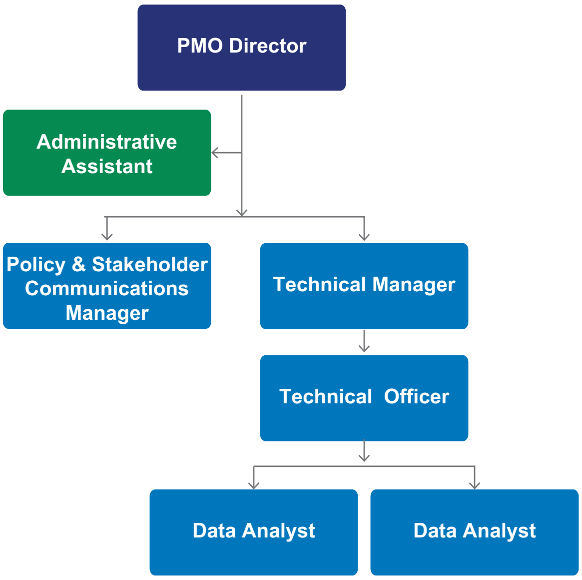
Figure 16: NIRP Governance Structure and Working Relationships



Note: The defined governance structure relates to the 'FMoP/NERCTCN-ISO Management Team' box in Figure 15
Source: NIRP Technical team

The structure and staffing of the PMO (Figure 17) need to ensure that the team receives overall strategic leadership and relevant technical expertise while also allowing for the efficient management of the NIRP process. To achieve this, it is proposed that the PMO team will involve seven key positions and one administrative assistant. Following feedback received as part of the Draft NIRP workshop in November 2024, the number of staff from NERC that form part of the PMO structure will be matched by future ISO staff to ensure the smooth transition from NERC to the ISO when the ISO assumes responsibility of the NIRP, as NERC staff will not be transitioning into the ISO when this occurs. The team will be headed by the **PMO Director**, who will oversee the entire NIRP process and PMO operations and provide overall leadership and strategic direction to the team. The PMO Director will liaise with, coordinate, and provide strategic advice to government and sector stakeholders, and be responsible for the overall performance of the PMO reporting to the leadership of FMoP, NERC, ISO and the NIRP Working Group. An important point to note is that the function of transmission resource planning will be conducted by the TCN and modelled iteratively and in parallel with the least cost planning by the PMO. Therefore, the proposed structure reflects the requirement to model generation and distribution with transmission planning happening in parallel.

Figure 17: PMO organisation chart



Source: NIRP Technical team

Given the complexity of the NIRP, and the additional challenges related to the decentralisation of the power sector, there will be a need both for the rapid **establishment of the PMO** to achieve an effective NIRP process, and the equally crucial need to secure solid Federal Government of Nigeria (FGN) and broader stakeholder (including the States) buy-in to the ownership of, and benefit from the NIRP. The latter typically requires time and patience, which may be at odds with the technical imperative of establishing the capacity for developing an IRP quickly. The key observations and focus areas identified to ensure the timely establishment of the PMO while maximising stakeholder buy-in include:

- A need for clear communication of purpose and benefits
- Addressing the location and reporting structure of the PMO is crucial
- Rapid staffing and capacity building are necessary to ensure effective PMO operations
- Proactive stakeholder engagement is crucial
- Initiating data collection and early deliverables will demonstrate progress and build confidence in the PMO's capabilities
- Donor coordination is essential for a unified approach to supporting the NIRP process
- Emphasising inclusivity and transparency throughout the process of establishing the governance arrangements for the NIRP

6.3 Modelling and PLEXOS software adoption

The most important aspect of the NIRP modelling is the **NIRP PLEXOS model** itself. The current NIRP model will provide the basis for the more detailed NIRP model which will be developed in tandem with TCN's Transmission Master Plan during 2025. The current model will be transferred to and owned by FMoP and NERC. Ultimately, its ownership and management will devolve to the ISO. Wherever ownership and management reside, training of dedicated personnel is a vital element.

Discussions with Energy Exemplar, PLEXOS software developer, have been held with NERC and TCN including a visit from Energy Exemplar to Nigeria in week commencing 4 November 2024 to present the solutions and support that could be provided in the context of the NIRP to a wider number of stakeholders, and especially the PMO entities. This is to ensure a smooth transition and adoption of the PLEXOS software and its use for the purposes of the NIRP at a National and at a state level, owned by Nigeria.

A significant aspect of early discussions has been on a standardised provision of data in Excel by all States that automatically sync to a PLEXOS cloud NIRP model, and a multi-tenanted application of PLEXOS that can support all 36 States. Such a setup would ensure consistency between National and state level IRPs allowing:

- Each state to access the full National model, enabling them to align their IRPs with National objectives such as renewable energy targets or carbon emissions goals.
- States to propose candidate projects or changes to generation capacity within their region, but all decisions must align with fixed components of the National model, ensuring National priorities are upheld.
- Co-optimisation of resources across National and state levels.
- Oversight by the PMO that manages the National model and incorporates state inputs and updates to the NIRP as needed.

Discussions on the hand over, licence procurement and setup, and the training of the PMO staff are ongoing and will follow the handover of the NIRP to NERC initially and the ISO when established.

Annexes

Annex A Index to previous NIRP reports

The table below provides an overview of the previous NIRP milestone reports and the key NIRP building blocks they cover. For detailed information on any topic specific technical parameters and data inputs, please refer to their respective reports, as outlined below. Summaries of the key findings from the M6 Demand forecast and M7 Resource assessment reports are also provided in Annex B and Annex C respectively.

Table 13: Index to previous NIRP reports

Milestone report	Key NIRP building block covered
M6 Demand forecast	• Demand forecasting methodology • Demand forecast key input assumptions • Sectoral analysis • Low, base and high scenario demand forecasts for: o Sent-out energy o Peak demand o Demand forecast by economic activity
M7 Resource assessment	• Overview of on-grid existing power plants and generation • Overview of off-grid electricity • Primary energy resources for power generation in Nigeria • Emerging technologies • Discussion of future expansion options • Discussion on distribution requirements
M8 Scenario options	• Approach developing the NIRP scenarios and sensitivities • Main scenario dimensions • Proposed draft scenarios • Proposed draft sensitivity options
M9 Least cost plans	• Least cost model inputs • Parallel model of costs of self-generation • Final NIRP scenarios and sensitivities • Generation least cost plan results
M10 Transmission Master Plan progress report	• Transmission Master Plan status
M11 Nigeria Integrated Resource Plan (NIRP)	• Regional and transmission consideration • NIRP key assumptions, scenario and sensitivities • NIRP modelling results • Stress tests for the NIRP • Overview of the implementation of the NIRP

Annex B Summary of Demand forecast report (M6)

Demand forecast assumptions

The specific assumptions which have been used to generate the demand forecasts are summarised in the table below. In addition, two general assumptions which apply to all three forecast scenarios (low, base and high) are:

- Universal access to electricity will be achieved by 2030.
- Auto-production and load shedding amounts to 49% of on-grid consumption in the base year. This is based on observations made in the most recent years. The allocation of this share between sectors is made as follows in the absence of actual data: Industrial 45%, Residential 25%, Commercial 25%, Public 4% and liquefied natural gas (LNG) 1%.

Table 14: Summary of input assumptions for the demand forecast scenarios

<table>
<tr><th colspan="2">Category</th><th>2022 value</th><th>2060 value</th><th>Unit</th><th>2022-2045 growth rate</th><th>2045-2060 growth rate</th></tr>
<tr><td colspan="2">Total population</td><td>217</td><td>440</td><td>million</td><td>2.1%</td><td>1.5%</td></tr>
<tr><td rowspan="3">GDP (real)</td><td>Low</td><td>74.6</td><td>383,148</td><td rowspan="3">2010 Tn Naira</td><td>4.6%</td><td>4.2%</td></tr>
<tr><td>Base</td><td>74.6</td><td>852,926</td><td>6.8%</td><td>6.3%</td></tr>
<tr><td>High</td><td>74.6</td><td>1,442,789</td><td>8.2%</td><td>8.0%</td></tr>
<tr><td rowspan="3">T&D losses</td><td>Low</td><td>8.2 21.0</td><td>6.0 10.0</td><td rowspan="3">%</td><td rowspan="3">MYTO targets to 2026:
Tx = 6.5%
Dx = 12.8%</td><td rowspan="3">Thereafter steady improvement in loss management, especially in the high scenario</td></tr>
<tr><td>Base</td><td>8.2 21.0</td><td>4.5 8.0</td></tr>
<tr><td>High</td><td>8.2 21.0</td><td>3.0 6.0</td></tr>
<tr><td colspan="2">Load factor</td><td>71</td><td>76</td><td>%</td><td colspan="2">76% from 2013 - 2060</td></tr>
<tr><td colspan="2">Off-grid</td><td>1%</td><td>8%</td><td>% total demand</td><td colspan="2">off-grid peaks at 10% in 2050</td></tr>
</table>

Headline summary of the base demand forecast

The following table provides a ‘headline’ summary for the Base case scenario of the on-grid and off-grid energy and peak demand forecasts over two time periods: 2022-2045, a 23 year period in line with the planning horizon typically used for IRP studies, and the longer 38 year period 2022-2060, which is the full extent of the demand forecast up to the Nigeria’s target year for net zero.

Table 15: Headline base demand forecast values and growth rates for 2022-2045 and 2022-2060

	2022		2045		2060		2022-2045	2022-2060
Units	TWh	GW	TWh	GW	TWh	GW	% AAG	% AAG
Total demand (grid and off-grid combined)	59.6	9.0	328.6	49.4	870.9	130.8	7.7%	7.3%
Demand growth from 2022 actual on-grid	32.3	4.8					11.0%	9.2%
Off-grid*	0.6	0.09	31.9	4.8	69.7	10.5	20.2%	14.4%

*Excluding oil/gas auto-producers; peak is the equivalent of on-grid peak demand absorbed by off-grid

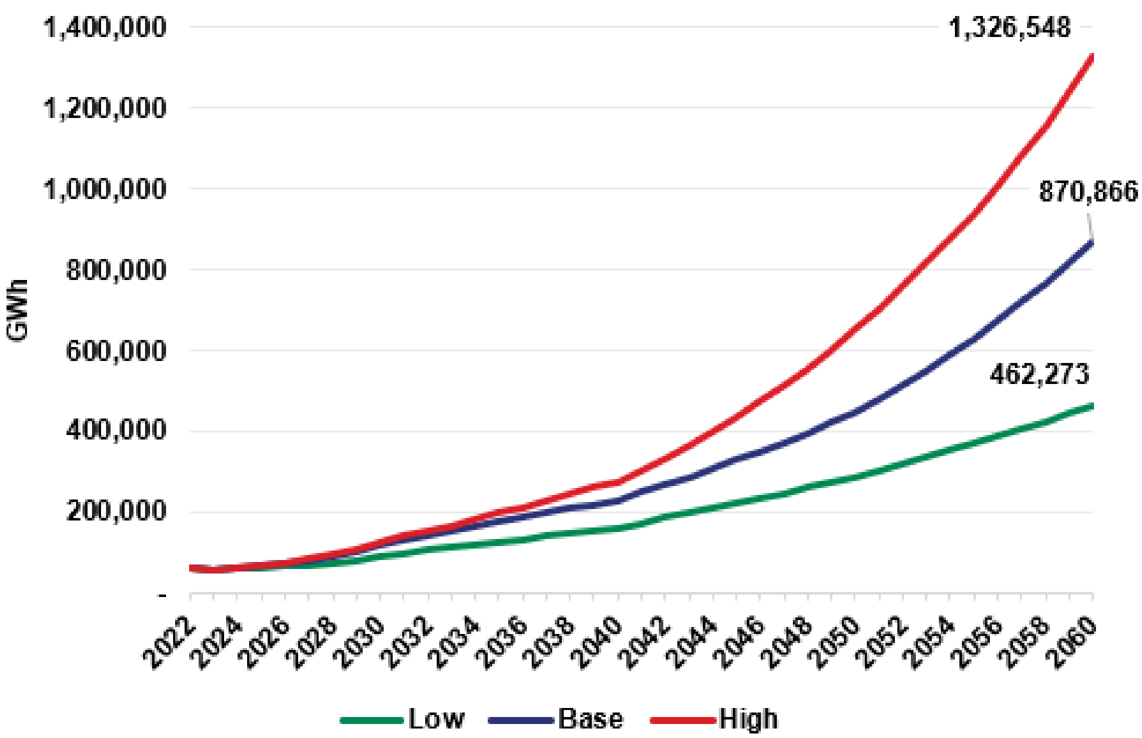
The higher rate of growth in the second row reflects the grid having to expand both to accommodate 'organic' growth from electrification, population and GDP growth and the progressive elimination of load shedding and auto-production.

Sent-out demand forecasts

Sent-out energy demand forecast – grid and off-grid combined

In the Base case, total sent-out energy (grid and off-grid) increases at an annual average growth rate of 7.3% from 60 TWh in 2022 to 871 TWh in 2060. The growth rate for 2023-2030 is 10.8% per year and for 2030-2045 the growth is 6.9% per year.

Figure 18: Sent-out energy demand forecast – grid and off-grid combined (GWh)

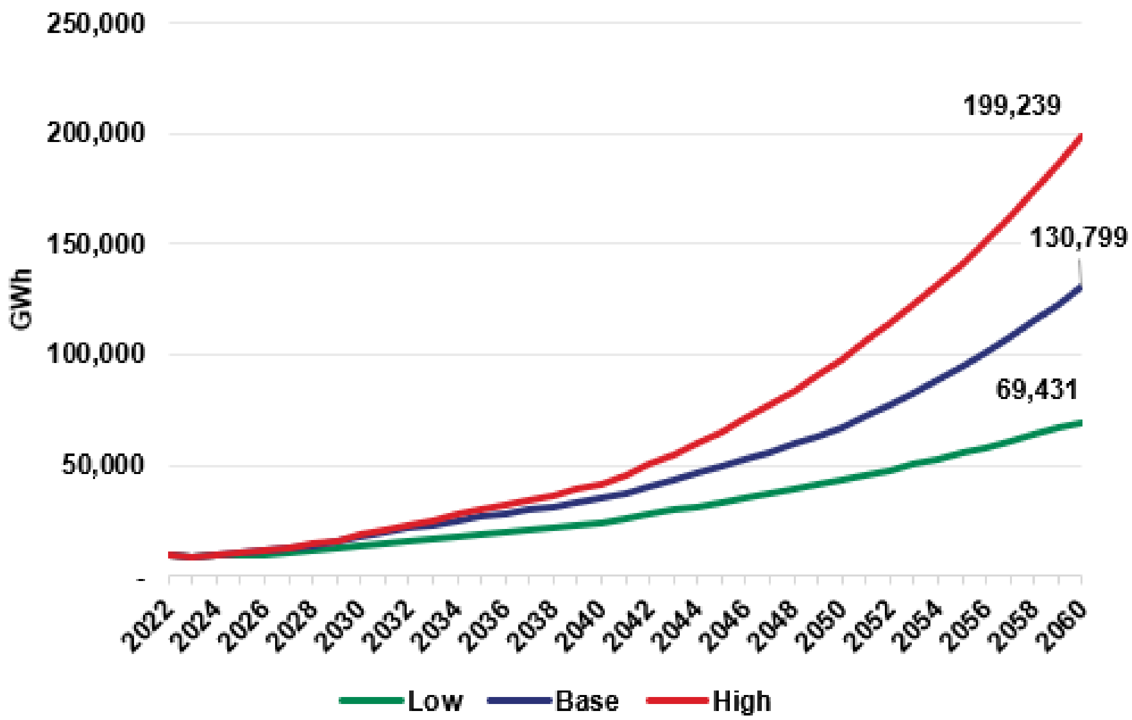


Note that comparisons to historical include auto-production and load shedding. Higher growth rates in the early years will be required for on-grid only demand as electricity shifts to on-grid from auto-producers and with the reduction in load shedding.

Sent-out peak demand forecast – grid and off-grid combined

In the Base case, total sent-out peak demand (grid and off-grid) increases from 9 GW in 2022 to 131 GW in 2060.

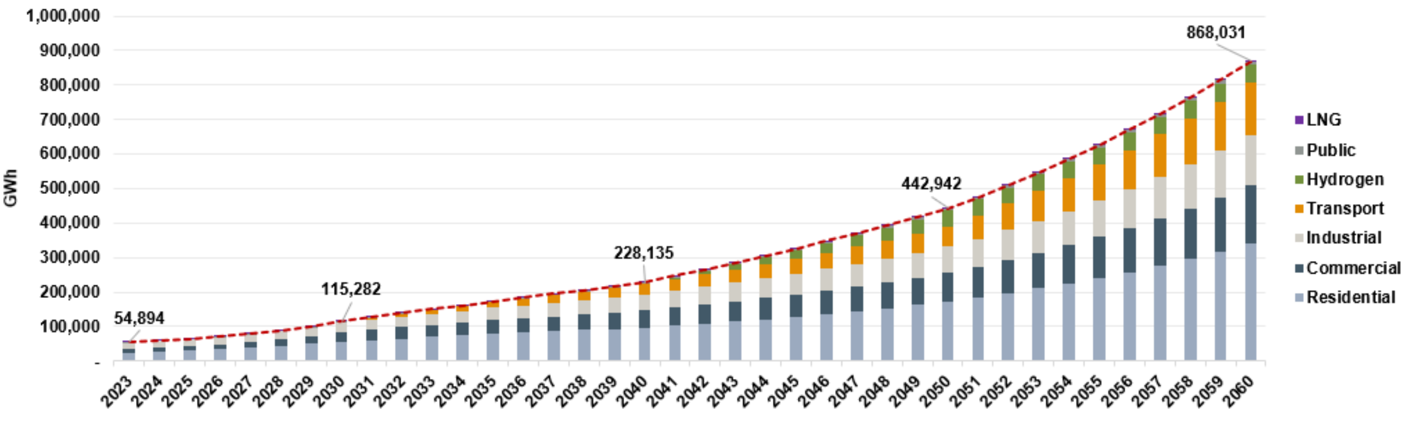
Figure 19: Peak demand forecast – grid and off-grid combined (MW)



Sectoral energy demand forecasts

The sectoral evolution of demand in the Base case is shown in the figure below.

Figure 20: Base case total energy sent-out per sector



Source: NIRP Technical team analysis; figures include total forecast of demand on-grid + off-grid and exclude exports

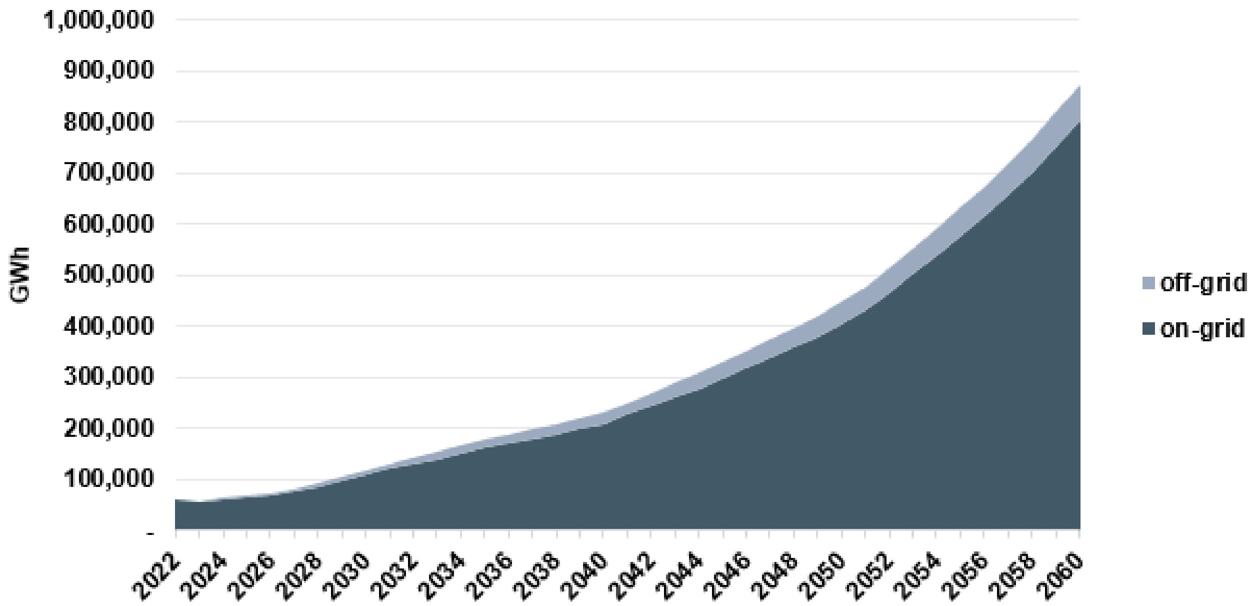
Residential demand grows very rapidly (at 13.5% per year) in the period to 2030 during which universal access is being achieved. To sustain the projected rate of GDP growth, industrial and commercial demand also grow quite rapidly in the middle years. Over the full 2023-2060 period, the overall annual average growth rates for these three main components of demand are Residential 6.4%, Commercial 6.8% and Industrial 5.9%. The electrification of transport only picks up from 2030 onwards with an average annual growth rate between 2032 and 2060 of 13.1%

which is higher at the start as transport shifts to power. Similarly, power demand for hydrogen production only starts from 2041 with an annual average growth rate between 2042 and 2060 of 10.9%.

Split between on-grid and off-grid demand

The figure below shows the overall split between off-grid and on-grid for the Base case.

Figure 21: Base case split on-grid vs off-grid energy demand forecast



Source: NIRP Technical team analysis

On-grid only sent-out demand

The demand forecasts used are the off-grid and the on-grid only sent-out demand. In the Base case, on-grid only energy is projected to grow to 222 TWh and peak demand to 33 GW.

Figure 22: Sent-out energy demand forecast (on-grid)

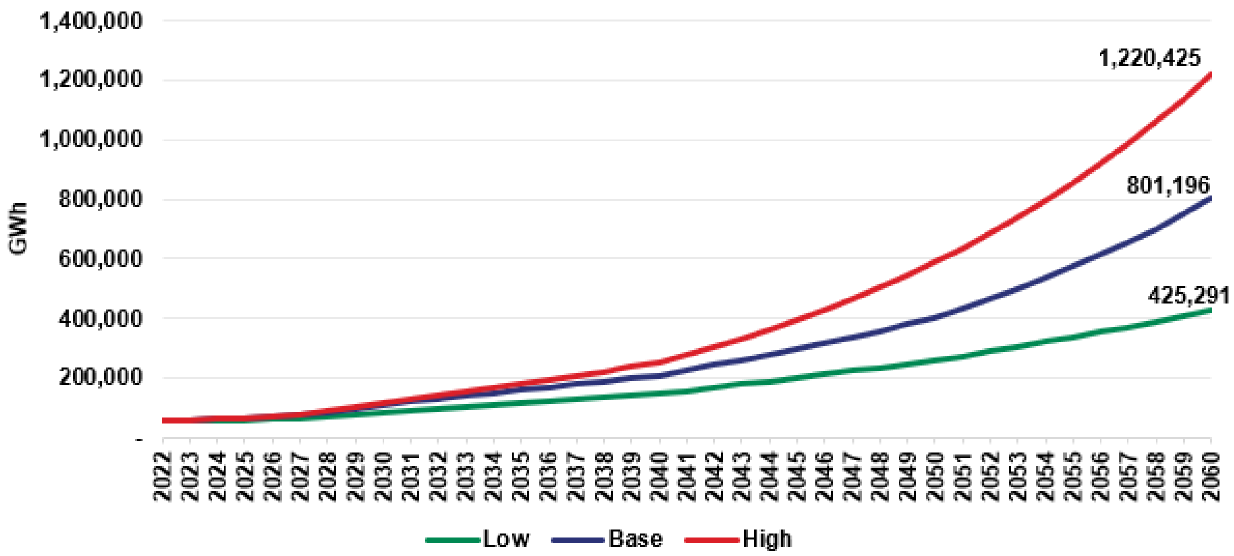
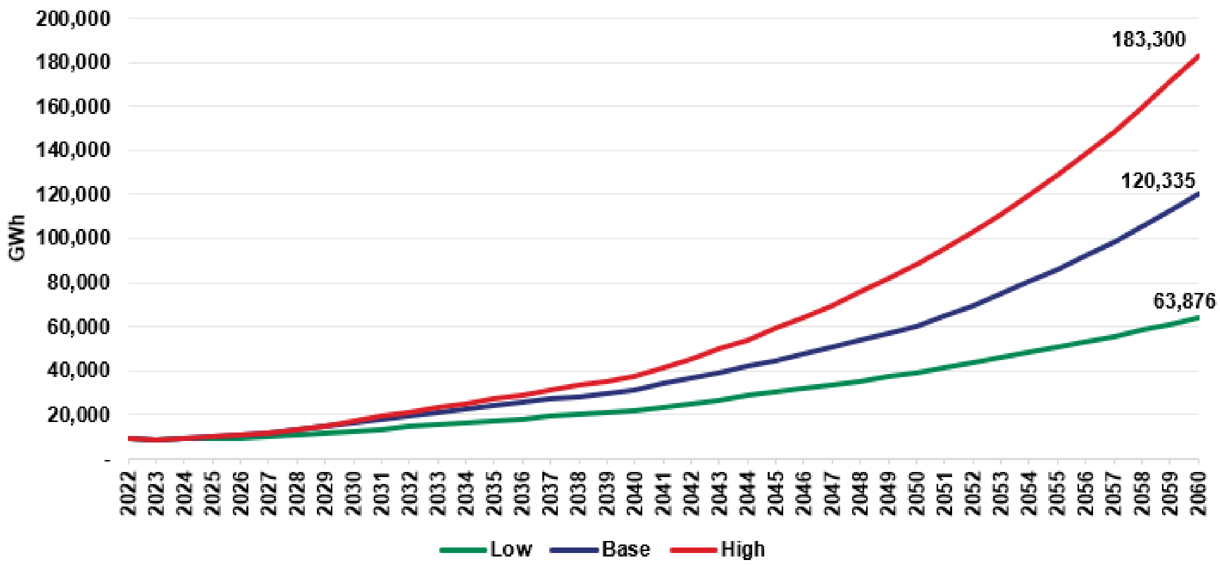


Figure 23: Peak demand forecast (on-grid)



Annex C Summary of Resource assessment report (M7)

Existing generation

Given the disparity between installed and generating capacity in the Nigerian grid, the need for optimal use of existing generation plant has been identified as a key priority policy issue in the sector. The current power system has a total installed capacity of 10.8 GW split between gas and hydro plants (see Table 5 in next sub-section below). On paper this is sufficient to meet current peak demand of around 9 GW, but due to network constraints, fuel supply interruptions and vandalism only 5.2 GW[15], or 48% of total installed capacity is being utilised, meaning that a large portion of the interconnected load is not adequately connected to the existing available capacity.

In addition, many of the existing plants are unreliable because they suffer from recurrent problems such as inadequate maintenance and repair leading to trips, faults, and leakages that frequently make them unavailable for evacuation to the National grid. In the early years of the NIRP planning period the focus should be on alleviating the bottlenecks to eliminate disparities between generated power and wheeled power to end-users and to ensure current and future capacity additions can adequately supply demand. Other issues, such as the need to improve economic generator dispatch capacity and planning, are further covered in the 2018 ECOWAS WAPP Master Plan for Generation and Transmission of Electricity Energy.

Committed and candidate generation technologies

The M7 Report provides a detailed assessment of Nigeria's energy resources, covering oil, natural gas, tar sands, hydropower, solar, wind, biomass and nuclear resources. It also analyses emerging technologies: carbon capture usage and storage (CCUS), including the bioenergy variant, BESS and hydrogen.

The resources and technologies taken forward for the generation least cost analysis in the M7 Report are:

- **Generation technologies** – gas, hydro, solar PV, solar CSP, wind, biomass and nuclear.
- **Emerging decarbonisation technologies** – CCUS, BESS, BECCS and hydrogen.

The tables below summarise the information available on existing committed and candidate gas, hydropower, solar and wind plants. The total of all categories is just short of 440 GW.

Table 16: Existing and committed gas, solar, wind and hydropower generation projects

Technology	Existing project		Committed project[1]	
	No.	MW	No.	MW
Gas3	21	8,804	-	-
Hydropower	4	1,978	1	700
Solar PV	-	-	14	1,125
Solar CSP	-	-	-	-
Wind	-	-	-	-
Total	**25**	**10,782**	**15**	**1,825**

[1.] Only includes Zungeru hydro plant and the 14 solar IPPs. Following discussions with NERC and TCN no further committed plants agreed to be added due to lack of financial closure.

Sources: Summary from text tables drawn from many different sources

Table 17: Candidate gas, hydropower solar and wind projects

Technology	Candidate projects
	Allowed maximum capacity (GW)[1]
Gas3	63,360[2]
Hydropower	18,600[3]
Solar PV	250,000
Solar CSP	88,700
Wind	3,200

[1.] Maximum capacity allowed to be built per technology type based on resource assessment. Inputs received from the Working Group, with research and assumptions made by the modelling team.
[2.] Assumption based on gas pipeline projects. Includes Gas + CCUS potential
[3.] Includes site specific and generic hydro plants.
Total hydro potential including existing and committed is at 21 GW
Sources: Inputs received from the Working Group, with research and assumptions made by the modelling team

At the time when the analysis was conducted, there were no known specific candidate projects in Nigeria in solar CSP, biomass, nuclear, BESS, BECCS and hydrogen and hence generic project characteristics were used in the least cost modelling. As there are limited data and information available to guide assessment of these emerging technologies, limited capacity for each of these emerging technologies was allowed in the model. Specifically, the allowed maximum capacity for BECCS and biomass is 6.2 GW and 8.2 GW, respectively, with BECCS only allowed as a candidate from 2035 onwards. Similarly for hydrogen, capacity built was limited to 3.5 GW per year and from 2035 onwards. For nuclear, a maximum number of four plants was assumed, each with a capacity of 1.6 GW, with a maximum number of two plants built per year. Lastly for nuclear SMR, a maximum capacity addition of 1.5 GW per year is assumed. Both nuclear candidate options, large and SMRs, are only allowed from 2040 onwards

Annex D Regional Level Information Gathered

Table 18 Regional level information gathered

Information	Source
Information on existing transmission networks between regions and their capacity	• NIRP working group • TCN
Average network unit costs	• TCN • 2018 ECOWAS WAPP Master Plan for Generation and Transmission of Electricity Energy • Master plan Study on National Power System Development in Nigeria, JICA (2019)
Regional solar capacity factors and profiles	• Globalsolaratlas.info (World Bank Group, ESMAP, SOLARGIS) • Master plan Study on National Power System Development in Nigeria, JICA (2019)
Regional wind capacity factors, profiles and regional resources	• Master plan Study on National Power System Development in Nigeria, JICA (2019) • globalwindatlas.info (World Bank Group, ESMAP, SOLARGIS) • Renewables.ninja
Potential hydro development sites and hydro seasonal production	• Master plan Study on National Power System Development in Nigeria, JICA (2019) • Historical hourly generation profiles received by NERC
Potential location of gas and gas + CCGT (gas pipeline project analysis)	• Nigerian Gas Masterplan (NGM) – 2008 • National Gas Policy (NGP) – 2017 • The National Integrated Infrastructure Masterplan (NIIMP) - 2020. • Nigeria Power Sector Programme (NPSP), Gas assessment draft report; latest updates on projects
Regional demand, household, and population data	• Nigeria Living Standards Survey 2018-19, National Bureau of Statistics • NERC annual and quarterly reports • Master plan Study on National Power System Development in Nigeria, JICA (2019) • Network companies' Performance Improvement Plans • Demographic and Health Survey, National Population Commission
Interconnectors to neighbouring countries (existing and future)	• TCN • Master plan Study on National Power System Development in Nigeria, JICA (2019)

Annex E Zonal Split for Candidate Generation Options

Technology	Allowed maximum capacity (GW)	Technology	Allowed maximum capacity (GW)
Gas		**Nuclear**	
Zone 1	42	Zone 1	6.4
Zone 2	19	**Nuclear SMR**	
Zone 3	14	Zone 1	2
Zone 4	47	Zone 2	1
Gas + CCS		Zone 3	1
Zone 4	15	Zone 4	2
Hydropower		**Biomass**	
Zone 1	4	Zone 1	3
Zone 2	1	Zone 2	2
Zone 3	12	Zone 3	2
Zone 4	1	Zone 4	2
Solar PV		**BECCS**	
Zone 1	25	Zone 4	6.6
Zone 2	75	**Hydrogen**	
Zone 3	125	Zone 1	66
Zone 4	25	Zone 2	66
Solar CSP		Zone 3	66
Zone 1	9	Zone 4	66
Zone 2	27		
Zone 3	44		
Zone 4	9		
Wind			
Zone 1	1		
Zone 2	1		
Zone 3	2		

Annex F Detailed NIRP scenario results

Table 19: Generation 2024 – 2045 (TWh)

(TWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas	22.3	21.8	30.2	34.2	39.2	43.4	49.9	57.9	64.5	71.7	79.6	88.0	88.1	87.7	90.3	89.8	89.1	84.4	79.2	74.0	70.2	64.5
Hydro	9.1	12.8	12.8	13.4	16.5	19.5	24.0	30.3	36.4	41.3	46.6	53.2	57.9	62.3	62.6	62.6	62.8	72.6	84.6	94.8	103.6	103.9
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0	12.0
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.01	0.01	0.01	0.3	0.3	0.3
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	0.3	0.7	1.1	1.4	1.8	1.8	1.8	1.9	4.0	6.7	9.3	12.0	15.8	22.1	30.9	40.5	50.0	59.4	72.4	85.3	97.6
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.5	0.6	1.1	2.0
DSM	-	0.7	1.7	3.9	6.1	8.3	10.5	12.7	15.0	17.2	19.4	21.7	22.9	24.1	25.3	26.5	27.3	28.9	29.3	28.5	27.6	27.7
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	0.7	2.6	3.6
Total	**31**	**36**	**45**	**53**	**63**	**73**	**86**	**103**	**118**	**134**	**152**	**172**	**181**	**190**	**200**	**210**	**220**	**236**	**253**	**271**	**292**	**312**

Table 20: Capacity additions by technology (GW)

(GW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas	-	-	-	-	-	0.3	1	1	1	2	3	-1	0.4	2	1	1	0.3	-1	-0.1	-1	-
Hydro	1	-	0.1	1	1	1	1	1	1	1	1	1	1	0.1	-	-	2	2	2	2	0.2
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	2
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0.1	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	0.2	0.3	0.2	0.2	0.3	-	-	-	1	2	2	2	2	4	5	6	6	6	8	8	8
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.3	0.3
DSM	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	1	0.4	2	1
Total	**1**	**0.4**	**1**	**1**	**1**	**1**	**3**	**2**	**4**	**5**	**6**	**2**	**4**	**6**	**7**	**7**	**8**	**8**	**11**	**11**	**11**

Table 21: Total installed capacity by technology (GW)

(%)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas	8.8	8.8	8.8	8.8	8.8	8.8	9.1	10.3	11.2	12.7	14.3	17.0	16.3	16.7	18.2	19.2	20.5	20.8	20.0	19.9	18.5	18.5
Hydro	2.0	2.7	2.7	2.8	3.4	4.0	4.8	6.0	7.2	8.1	9.1	10.4	11.2	12.1	12.1	12.1	12.1	14.1	16.4	18.5	20.3	20.6
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	2.3
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.7	0.7	0.7	0.7	0.7	0.7
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	0.2	0.4	0.6	0.8	1.1	1.1	1.1	1.1	2.4	4.1	5.7	7.4	9.7	13.5	18.8	24.6	30.4	36.2	44.5	52.8	61.1
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.3	0.6	0.9
DSM	-	0.1	0.2	0.4	0.7	0.9	1.2	1.5	1.7	2.0	2.2	2.5	2.6	2.7	2.9	3.0	3.2	3.3	3.4	3.6	3.7	3.9
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.8	1.2	2.7	3.4
Total	**11**	**12**	**12**	**13**	**14**	**15**	**16**	**19**	**21**	**25**	**30**	**36**	**38**	**41**	**47**	**54**	**61**	**69**	**78**	**89**	**100**	**111**

Table 22: Capacity factors by technology (%)

(%)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas	29%	28%	39%	44%	51%	56%	62%	64%	66%	65%	63%	59%	62%	60%	56%	53%	50%	46%	45%	43%	43%	40%
Hydro	53%	55%	55%	55%	56%	56%	57%	58%	58%	58%	58%	59%	59%	59%	59%	59%	59%	59%	59%	59%	58%	58%
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25%	60%
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1%	0.1%	0.1%	0.1%	4%	5%	6%
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	20%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	18%	18%
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22%	27%	20%	19%	24%

Table 23: Investment costs 2024 – 2045 (bn$)

(bn$)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas	-	-	-	-	-	-	0.3	1	1	2	2	3	1	1	2	1	2	0.4	-	0.3	-	-
Hydro	-	-	-	0.1	1	1	2	3	3	2	2	3	2	2	0.1	-	-	4	5	5	4	1
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	5
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.1	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	-	-	-	-	-	-	1	2	1	1	2	3	5	6	5	5	8	8	8
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.2	0.3	0.3
DSM	-	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	0.3	2	1
Total	**-**	**0.01**	**0.02**	**0.2**	**1**	**1**	**2**	**4**	**4**	**5**	**5**	**7**	**4**	**4**	**6**	**6**	**8**	**10**	**11**	**13**	**15**	**14**
Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.03	0.4	0.1	0.2	0.2	0.2
Total + transmission	**-**	**0.01**	**0.02**	**0.2**	**1**	**1**	**2**	**4**	**4**	**5**	**5**	**7**	**4**	**4**	**6**	**6**	**8**	**11**	**11**	**14**	**15**	**14**

Annex G Detailed zonal generation results by technology

Table 24: Generation 2024 – 2045 (TWh), zonal results

(TWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Zone 1																						
Gas	12.8	12.8	13.5	13.9	15.1	16.8	18.5	20.4	24.0	27.9	32.0	27.5	26.2	29.7	36.4	36.6	43.1	41.0	37.6	34.7	31.2	29.4
Hydro	8.9	12.6	12.6	12.6	14.5	15.5	16.5	18.6	20.9	23.1	24.9	26.6	26.6	26.9	26.9	26.9	26.9	27.4	29.7	29.7	30.6	30.5
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.01	0.01	0.01	0.3	0.3	0.3
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	0.1	0.2	0.4	0.4	0.4	0.4	0.9	1.4	1.8	2.3	2.8	4.1	5.3	6.6	7.8	9.0	10.2	11.5	12.7
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.2
DSM	-	0.3	0.8	1.7	2.8	3.7	4.7	5.7	6.8	7.8	8.8	9.8	10.3	10.8	11.4	11.9	12.5	13.0	13.6	13.4	12.9	12.9
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.2	0.3
Total	**22**	**26**	**27**	**28**	**33**	**36**	**40**	**45**	**52**	**60**	**67**	**66**	**66**	**70**	**79**	**81**	**89**	**89**	**90**	**89**	**87**	**86**
Zone 2																						
Gas	-	-	-	-	-	-	0.9	3.8	8.2	13.3	17.2	21.5	21.9	20.9	21.9	22.6	19.2	17.4	17.3	16.0	17.6	15.4
Hydro	-	-	-	-	-	-	0.8	1.5	2.3	3.1	3.9	4.3	5.2	5.2	5.3	5.3	5.3	5.3	5.5	5.5	7.3	7.2
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	0.3	0.5	0.6	0.9	1.0	1.0	1.0	1.0	2.7	4.4	6.1	7.9	9.5	11.2	15.5	19.8	24.1	28.3	31.8	35.7	38.9
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.6
DSM	-	0.1	0.3	0.7	1.2	1.6	2.0	2.4	2.9	3.3	3.7	4.2	4.4	4.6	4.8	5.1	5.0	5.5	5.4	5.0	5.1	5.2
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.3	2.2	3.1
Total	**-**	**0.4**	**1**	**1**	**2**	**3**	**5**	**9**	**14**	**22**	**29**	**36**	**39**	**40**	**43**	**49**	**49**	**52**	**57**	**59**	**68**	**70**
Zone 3																						
Gas	-	-	-	-	-	-	0.5	2.5	4.1	6.6	8.7	11.3	10.6	9.7	7.6	6.3	5.5	5.2	4.5	4.3	4.3	4.9
Hydro	0.2	0.2	0.2	0.2	1.0	3.0	5.0	7.6	9.9	11.0	13.0	16.6	19.7	23.7	24.0	24.0	24.0	33.4	42.9	53.1	59.2	59.8
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.5	4.3	7.2	10.1	12.9	15.8	22.8	29.4	36.2
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.5	0.5	0.7	1.1
DSM	-	0.1	0.2	0.5	0.8	1.1	1.4	1.7	2.0	2.3	2.6	2.9	3.1	3.2	3.4	3.6	3.5	3.9	3.7	3.6	3.4	3.5
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0**	**0**	**1**	**1**	**2**	**4**	**7**	**12**	**16**	**20**	**25**	**31**	**34**	**38**	**39**	**41**	**43**	**56**	**67**	**84**	**97**	**105**

Zone 4																						
Gas	9.5	9.0	16.7	20.3	24.1	26.7	29.9	31.2	28.3	23.8	21.6	27.7	29.3	27.4	24.4	24.3	21.3	20.8	19.8	19.1	17.2	14.9
Hydro	-	-	-	0.6	1.0	1.0	1.8	2.6	3.3	4.1	4.9	5.7	6.5	6.4	6.4	6.4	6.5	6.4	6.5	6.5	6.5	6.4
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0	12.0
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.6	1.1	1.5	2.0	2.4	2.9	4.1	5.2	6.4	7.5	8.7	9.8
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM	-	0.2	0.4	0.9	1.4	1.9	2.3	2.8	3.3	3.8	4.3	4.8	5.1	5.4	5.7	5.9	6.2	6.5	6.6	6.4	6.1	6.1
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.2	0.2
Total	**9**	**9**	**17**	**22**	**27**	**30**	**34**	**37**	**35**	**32**	**31**	**39**	**42**	**41**	**39**	**40**	**38**	**39**	**39**	**40**	**40**	**50**

Table 25: Total installed capacity by technology (GW), zonal results

GW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Zone 1																						
Gas	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.4	4.0	4.5	5.4	5.6	5.2	5.7	6.1	6.3	7.8	7.7	7.0	7.0	6.6	6.6
Hydro	1.9	2.6	2.6	2.6	3.0	3.2	3.4	3.8	4.2	4.6	5.0	5.3	5.3	5.4	5.4	5.4	5.4	5.5	5.9	5.9	6.1	6.1
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.7	0.7	0.7	0.7	0.7	0.7
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Solar PV	-	-	-	0.1	0.2	0.3	0.3	0.3	0.3	0.6	0.9	1.2	1.6	1.9	2.7	3.6	4.4	5.2	6.1	6.9	7.7	8.5
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.04	0.1	0.1
DSM	-	0.03	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.0	1.1	1.2	1.2	1.3	1.4	1.4	1.5	1.5	1.6	1.7	1.7
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	0.4	0.4
Total	**5**	**6**	**6**	**6**	**7**	**7**	**7**	**8**	**9**	**11**	**12**	**13**	**13**	**14**	**16**	**17**	**20**	**21**	**21**	**23**	**23**	**24**
Zone 2																						
Gas	-	-	-	-	-	-	0.1	0.5	1.1	1.7	2.2	2.8	3.0	3.0	3.4	3.7	3.8	4.2	4.2	4.3	4.3	4.3
Hydro	-	-	-	-	-	-	0.1	0.3	0.4	0.6	0.7	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.4	1.4
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	0.2	0.3	0.4	0.5	0.6	0.6	0.6	0.6	1.6	2.6	3.6	4.6	5.6	6.5	9.0	11.5	14.0	16.5	19.0	21.5	24.0
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.3
DSM	-	0.01	0.04	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	0.4	1.9	2.6
Total	**-**	**0.2**	**0.3**	**0.5**	**1**	**1**	**1**	**2**	**2**	**4**	**6**	**8**	**9**	**10**	**11**	**14**	**17**	**20**	**23**	**25**	**30**	**33**
Zone 3																						
Gas	-	-	-	-	-	-	0.1	0.3	0.5	0.9	1.1	1.5	1.6	1.6	1.6	1.6	1.8	1.8	1.8	1.9	1.9	1.9
Hydro	0.04	0.04	0.04	0.04	0.2	0.6	1.0	1.5	1.9	2.1	2.5	3.2	3.7	4.5	4.6	4.6	4.6	6.4	8.2	10.3	11.6	11.8
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.8	2.5	4.1	5.8	7.4	9.1	13.2	17.4	21.5
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.3	0.4	0.5
DSM	-	0.01	0.03	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.04**	**0.1**	**0.1**	**0.2**	**0.4**	**1**	**1**	**2**	**3**	**3**	**4**	**5**	**6**	**7**	**9**	**11**	**13**	**16**	**20**	**26**	**32**	**36**
Zone 4																						
Gas	5.8	5.8	5.8	5.8	5.8	5.8	5.8	6.1	5.7	5.5	5.5	7.0	6.5	6.4	7.1	7.5	7.1	7.1	7.1	6.6	5.7	5.7
Hydro	-	-	-	0.1	0.2	0.2	0.3	0.5	0.6	0.8	0.9	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Gas+CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	2.3
BECCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrogen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.4	0.8	1.1	1.4	1.8	2.1	2.9	3.7	4.6	5.4	6.2	7.1
Solar CSP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM	-	0.02	0.04	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9
Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.4	0.4	0.4
Total	**6**	**6**	**6**	**6**	**6**	**6**	**7**	**7**	**7**	**7**	**7**	**9**	**9**	**10**	**11**	**11**	**12**	**13**	**14**	**14**	**15**	**18**

Annex H Detailed results of the NIRP scenario by zone

Table 26: Summary of zone 1 results

		2024	2030	2040	2045
Capacity					
Peak demand	GW	2	5	13	18
Installed capacity (incl. storage)	GW	5	7	20	24
RES capacity	GW	2	4	10	15
Storage capacity (incl. solar CSP storage)	GW	-	-	-	0
Storage energy capacity (incl. solar CSP storage)	GWh	-	-	-	1
Average storage duration	hrs	-	-	-	2
RES capacity	% of total	39%	50%	53%	64%
Energy					
Energy demand	TWh	15,509	35,263	88,471	125,819
Storage Demand	TWh	-	-	-	315
Generation	TWh	21,756	40,107	89,128	85,950
Share of RES	%	41%	48%	44%	60%
Costs		**2024-45**	**% share**		
NPV of total costs	bn$	19	100%		
NPV of capex	bn$	8	44%		
NPV of fuel costs	bn$	**4**	20%		
NPV of variable O&M	bn$	3	17%		
NPV of fixed O&M	bn$	4	20%		
LCOE	$/MWh	35.4			
LCOE	c$/kWh	3.54			

Table 27: Summary of zone 2 results

		2024	2030	2040	2045
Capacity					
Peak demand	GW	1	2	6	9
Installed capacity (incl. storage)	GW	-	1	17	33
RES capacity	GW	-	1	13	26
Storage capacity (incl. solar CSP storage)	GW	-	-	-	3
Storage energy capacity (incl. solar CSP storage)	GWh	-	-	-	10
Average storage duration	hrs	-	-	-	4
RES capacity	% of total		69%	74%	77%
Energy					
Energy demand	TWh	4,385	15,011	45,061	67,674
Storage Demand	TWh	-	-	-	3,751
Generation	TWh	-	4,731	49,369	67,307
Share of RES	%		67%	57%	75%
Costs		**2024-45**	**% share**		
NPV of total costs	bn$	13	100%		
NPV of capex	bn$	10	79%		
NPV of fuel costs	bn$	**1**	7%		
NPV of variable O&M	bn$	1	6%		
NPV of fixed O&M	bn$	1	7%		
LCOE	$/MWh	63.1			
LCOE	c$/kWh	6.31			

Table 28: Summary of zone 3 results

		2024	2030	2040	2045
Capacity					
Peak demand	GW	0	2	5	7
Installed capacity (incl. storage)	GW	0	1	13	36
RES capacity	GW	0	1	10	34
Storage capacity (incl. solar CSP storage)	GW	-	-	-	-
Storage energy capacity (incl. solar CSP storage)	GWh	-	-	-	-
Average storage duration	hrs	-	-	-	-
RES capacity	% of total	100%	83%	82%	93%
Energy					
Energy demand	TWh	2,633	10,490	32,926	46,709
Storage Demand	TWh	-	-	-	-
Generation	TWh	210	7,230	43,091	105,407
Share of RES	%	100%	91%	86%	95%
Costs		**2024-45**	**% share**		
NPV of total costs	bn$	18	100%		
NPV of capex	bn$	14	82%		
NPV of fuel costs	bn$	**0**	2%		
NPV of variable O&M	bn$	1	8%		
NPV of fixed O&M	bn$	1	7%		
LCOE	$/MWh	79.4			
LCOE	c$/kWh	7.94			

Table 29: Summary of zone 4 results

		2024	2030	2040	2045
Capacity					
Peak demand	GW	1	3	6	9
Installed capacity (incl. storage)	GW	6	7	12	18
RES capacity	GW	-	0	4	8
Storage capacity (incl. solar CSP storage)	GW	-	-	-	0
Storage energy capacity (incl. solar CSP storage)	GWh	-	-	-	1
Average storage duration	hrs	-	-	-	2
RES capacity	% of total	-	7%	35%	47%
Energy					
Energy demand	TWh	7,973	17,465	42,843	61,075
Storage Demand	TWh	-	-	-	299
Generation	TWh	9,482	34,202	38,062	49,309
Share of RES	%	-	6%	33%	38%
Costs		**2024-45**	**% share**		
NPV of total costs	bn$	13	100%		
NPV of capex	bn$	6	48%		
NPV of fuel costs	bn$	**4**	30%		
NPV of variable O&M	bn$	1	10%		
NPV of fixed O&M	bn$	2	13%		
LCOE	$/MWh	42.2			
LCOE	c$/kWh	4.22			

FEDERAL MINISTRY OF POWER

The Federal Ministry of Power is responsible for making policy, overseeing and reporting on the implementation of the policy in the Nigerian Electricity Supply Industry on behalf of the of the Federal Government. In discharging this mandate, the Ministry is guided by the provision of this policy and the provisions of Electricity Act 2003.

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