Supplementary Information for 'Delivering low-carbon electricity systems in Sub-Saharan Africa: insights from Nigeria'

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Supplementary Note 1: Electricity demand – present and future

Hourly demand data for Nigeria is not publicly available and difficult to obtain. However, a study by Fichtner in collaboration with the Transmission Company of Nigeria (TCN) completed an investigation to determine the amount of actual electricity demand in the country, *i.e.* including the demand connected to the grid but not being met. The demand profile for two days in July 2016 was published and is illustrated in Fig. 1. This was extended and used as the demand profile for the country over the year. As there is minimal seasonality in Nigeria's demand patterns*, this was considered to be a reasonable approximation. An economic analysis carried out by the same Fichtner study also forecast the electricity demand for each distribution region until 2050. The analysis presented in this study scales the 2016 demand profile (by dividing the peak forecast demand for a future year by the peak during the days shown) to determine hourly demand in future years. Demand for each state is assumed to be equal to its share of population in its distribution zone, which is shown in Fig. 3.

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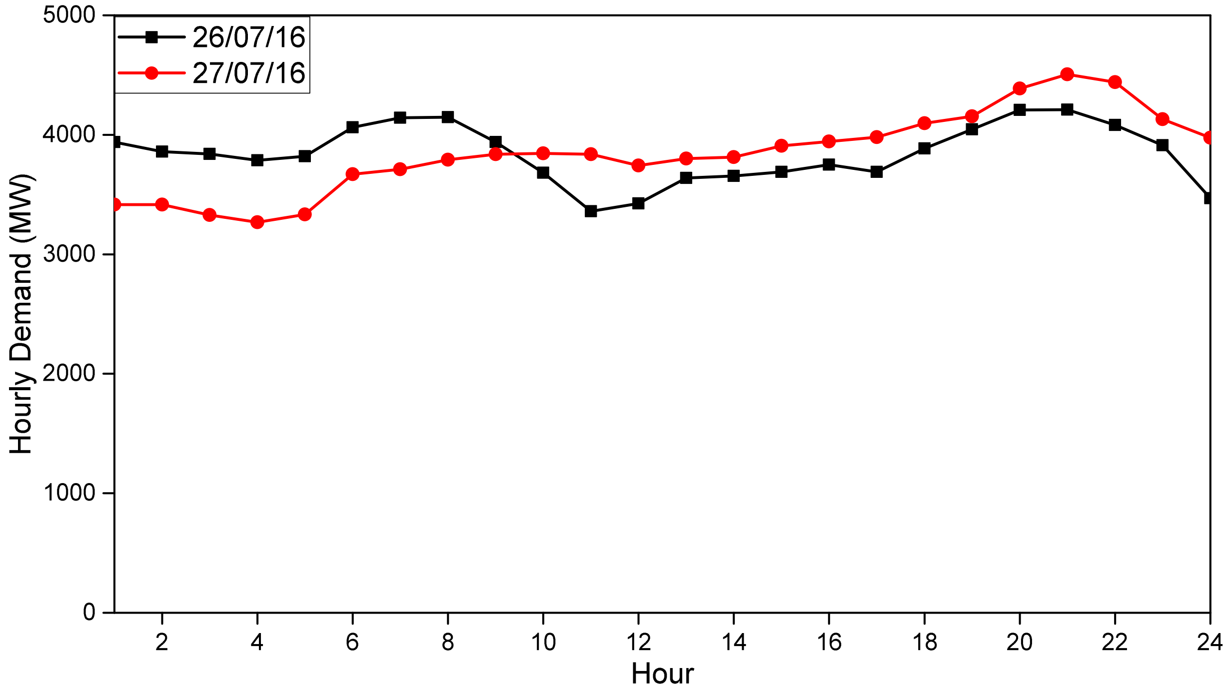
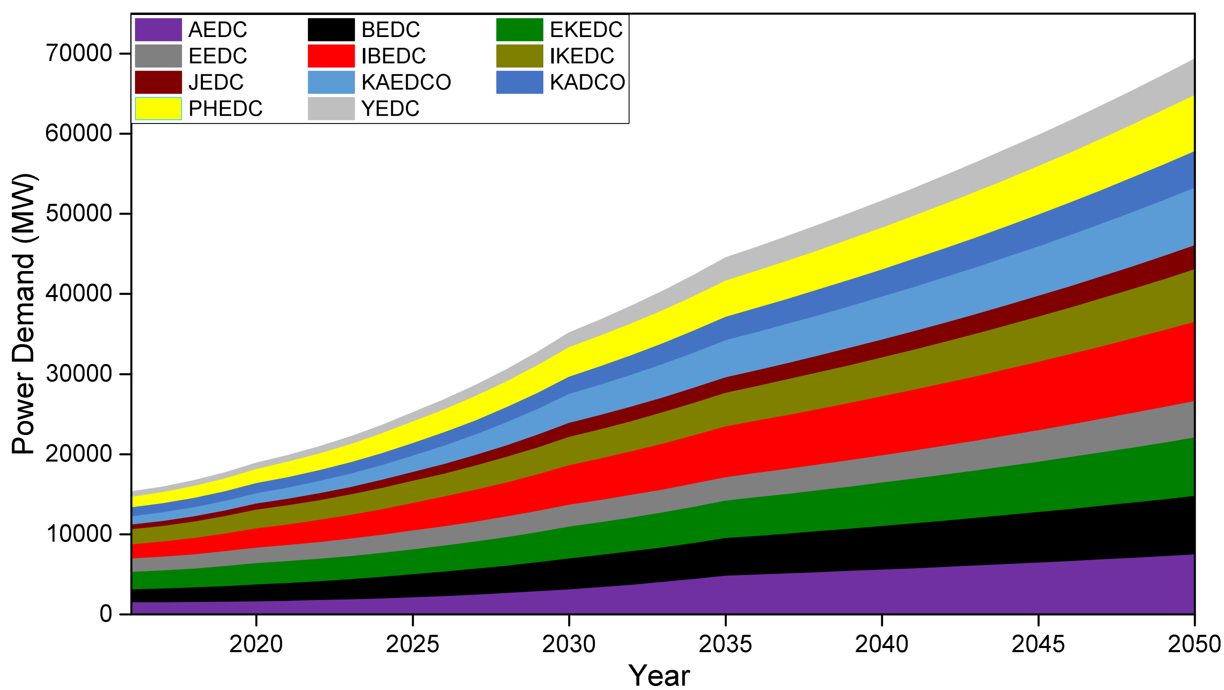
*Nigeria has two seasons: rainy and dry. Discussions with staff at the Transmission Company of Nigeria suggest that no changes in demand are observed between the two seasons. Additionally, no studies have been published suggesting otherwise.

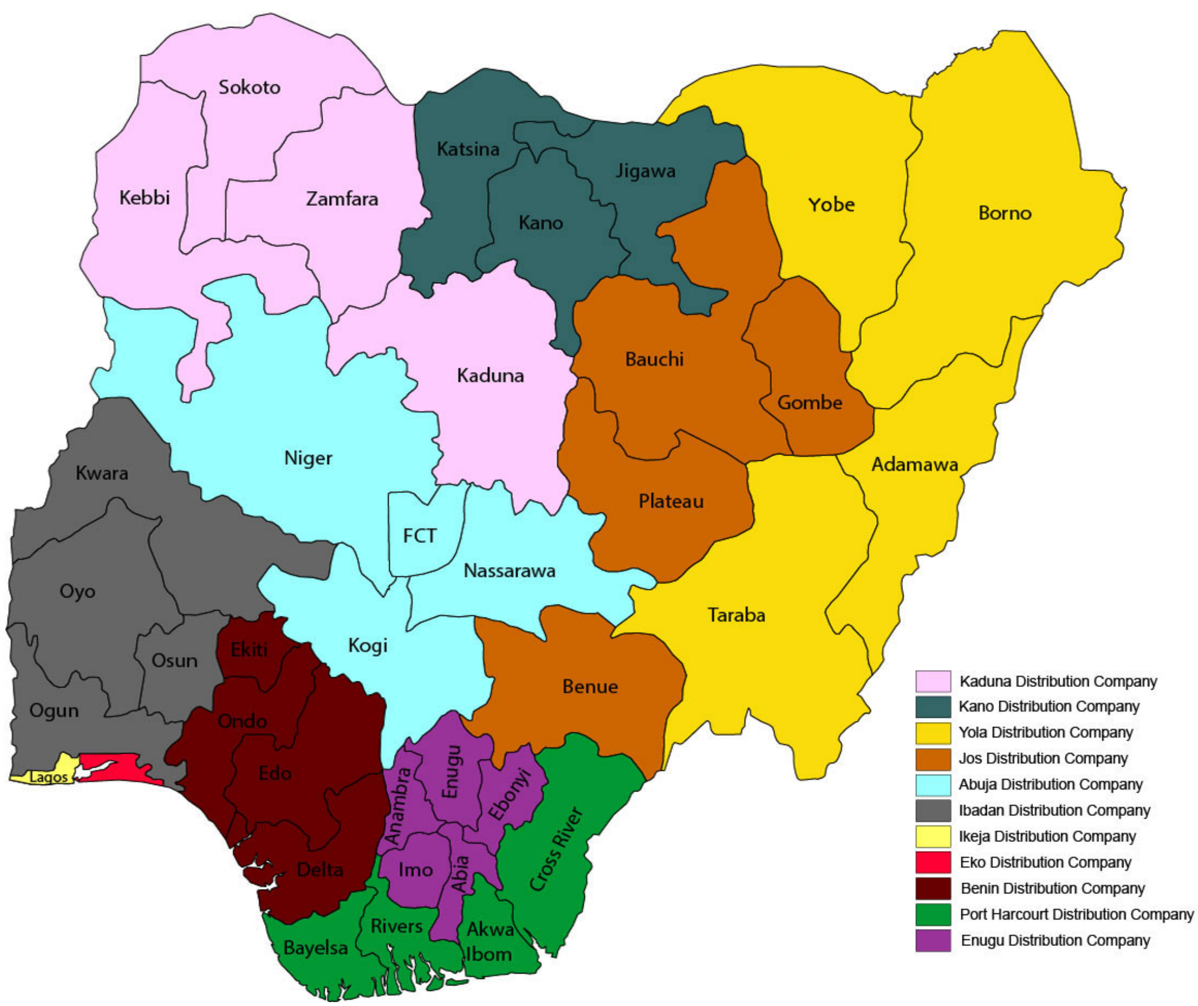


Supplementary Figure 1: Hourly power demand on 26/07/16 and 27/07/16 from the TCN National Control Centre, Osogbo[1]



Supplementary Figure 2: Total forecast demand (including suppressed demand) by distribution zone from 2016 to 2050[1]

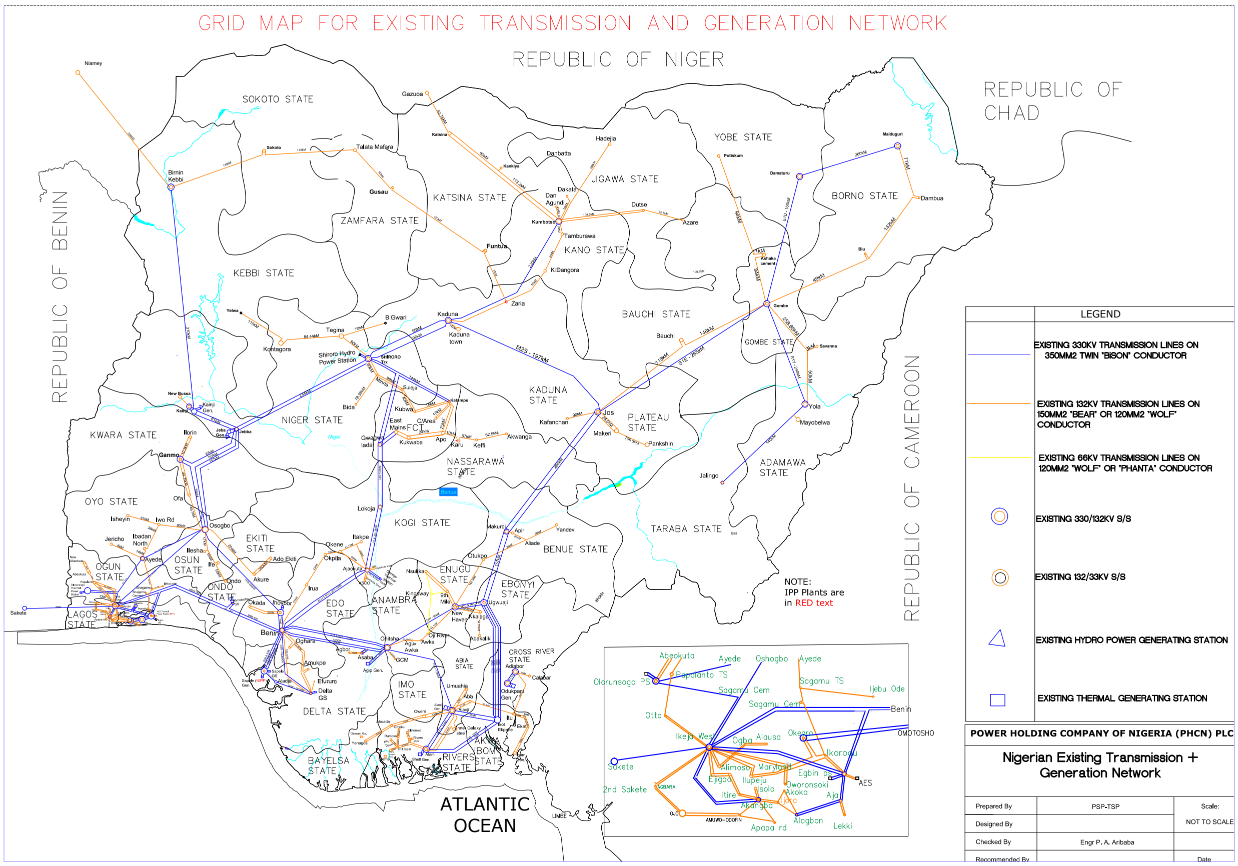
After the partial privatisation of the power sector in 2013, 11 successor distribution companies (DISCOs) were established and sold to private entities. Each DISCO is responsible for serving electricity consumers in a group of states. Fig. 3 shows the distribution zones established: Abuja Electricity Distribution Company (AEDC) – Kogi, Nassarawa and Niger states, and the Federal Capital Territory; Benin Electricity Distribution Company (BEDC) – Delta, Edo, Ekiti and Ondo states; Eko Electricity Distribution Company (EKEDC) – Lagos Island; Enugu Electricity Distribution Company (EEDC) – Abia, Anambra, Ebonyi, Enugu and Imo states; Ibadan Electricity Distribution Company (IBEDC) – Kwara, Ogun, Osun and Oyo states; Ikeja Electricity Distribution Company (IKEDC) – Lagos Mainland; Jos Electricity Distribution Company (JEDC) – Bauchi, Benue, Gombe and Plateau states; Kaduna Electricity Distribution Company (KAEDCO) – Kaduna, Kebbi, Sokoto and Zamfara states; Kano Electricity Distribution Company (KADCO) – Jigawa, Kano and Katsina states; Port-Harcourt Electricity Distribution Company (PHEDC) – Akwa-Ibom, Bayelsa, Cross-River and Rivers states; Yola Electricity Distribution Company (YEDC) – Adamawa, Borno, Taraba and Yobe states.



Supplementary Figure 3: Map showing the geographical remit of the 11 successor distribution companies established after the privatisation of the Nigerian power sector in 2013[2]

Supplementary Note 2: Existing Transmission Network

The ESONE model only considers power transmission between nodes (*i.e.* states). Fig. 4 illustrates the existing 132 kV and 330 kV interstate power transmission lines. In the initial year in the model (2020), the transmission network is defined as below.



Supplementary Figure 4: Map showing Nigeria's existing high-voltage power transmission network[3]

Supplementary Note 3: System-wide parameters

The system parameters implemented in the ESONE model are provided in Table 1. A minimum reserve capacity margin of 5% and dynamic reserve (added capacity reserve due to increasing penetration of iRES) of 15% of iRES generation is implemented in the ESONE model. This is based on the UK electricity system because the current security and reliability requirements in the Nigerian power system are well-below international security and reliability standards[4]. Network losses are provided by the Nigerian Electricity Regulatory Commission, the sector's regulator. The amount of dynamic reserve to compensate for the variability of intermittent renewables is taken from a study for the UK[5], as there are no studies available on the effects of intermittency on system operability within the Nigerian or sub-Saharan African (SSA) context.

The availabilities of solar and wind are obtained using *Renewables.ninja*, a tool that simulates hourly power output from solar and wind power plants using historical satellite data[6]. Hydro availability profiles are determined from the three existing hydroelectric power stations in Nigeria. How availability profiles are determined for each zone are described in detail in Section .

A discount rate of 5-15% was used in several studies to reflect the greater uncertainty of future cash flows (relative to developed economies)[1,7]. 10% was selected for base case scenarios and a sensitivity analysis was carried out on the value. No carbon capture and storage (CCS) technology has been deployed at scale in SSA and discussion of the technology within the African context is minimal so there are no reliable cost estimates for CO_2 transport and storage (T&S) infrastructure in SSA in the literature. The UK CO_2 T&S cost (implemented in the ESO-XEL model) was also assumed in the Nigeria case study. CCS is considered to be unavailable in the planning horizon considered for the Nigeria case study (2020 to 2050), with the exception of one sensitivity analysis carried out (see main article). Finally, the Value of Lost Load is estimated to be \$10,000/MWh; this ensures that unmet electric load is limited to <2% of annual demand even when the system demand constraint is relaxed.

Supplementary Table 1: Data sources for system parameters assumed in the ESONE model

Nigeria electricity system	Value	Data source(s)
Hourly electricity demand	-	1
Reserve margin	5% of demand	1
System inertia requirement	260 MW	1
Capacity reserve for intermittent renewables	15%	5
CO_2 emissions targets until 2050	-	8,9
Power transmission and distribution losses	15.4%	1
Value of lost load	10,000 \$/MWh	-
Hourly availability of solar, onshore wind and offshore wind	-	6,10–13
Discount rate	10%	1
CO_2 transport and storage costs	£10/t_{CO_2}	14

Supplementary Note 4: Technology parameters

Technology costs differ from country to country for technical, economic and sociopolitical factors. Typically, power generation costs in sub-Saharan Africa are lower than in developed countries because of fewer regulatory requirements and planning hurdles. The capital costs and efficiencies assumed for power generation in Nigeria are provided in Table 2. Technology capital cost reduction forecasts are taken from the International Energy Agency's (IEA) *World Energy Outlook 2018*.

Supplementary Note 5: Fuel prices

The operating costs of different power technologies are determined based on the following factors: fuel prices, efficiencies, carbon prices (assumed to be zero for Nigeria) and cost of CO_2 T&S. A range of fuel prices for power generation in Nigeria, obtained from the sources listed in Table 3, is considered in the analysis presented in this study. Where no range is provided (coal and uranium), data was insufficient as those resources have never been mined or used for power generation at scale in Nigeria.

Supplementary Table 2: Data sources for the technology costs and operational parameters implemented in the ESONE model

Technology	2020 CAPEX ($/kW)	2030 CAPEX ($/kW)	2040 CAPEX ($/kW)	Fixed O&M ($/kW/yr)	Efficiency (HHV basis)	Data sources reviewed
Steam	1,040	1,040	1,040	25	31%	[15]
Nuclear	4,000	4,000	4,000	170	37%	[15,16]
Coal (super-critical)	1,600	1,600	1,600	75	43%	[15]
Dedicated biomass-fired	2,150	2,150	2,150	75	35%	[15]
Combined cycle gas turbine (CCGT)	700	700	700	25	58%	[15]
Open cycle gas turbine (OCGT)	400	400	400	20	38%	[15]
Diesel (Off-grid)	2,981	2,981	2,981	15	50%	[15,17–19]
Coal post-combustion CCS	4,500	4,250	3,900	160	33%	[15]
CCGT post-combustion CCS	2,450	2,300	2,050	80	51%	[15]
Bioenergy with CCS (BECCS)	4,500	4,250	3,900	160	35%	[14,20–24]
Onshore Wind	1,860	1,740	1,720	46	100%	[15]
Offshore Wind	3,900	2,900	2,900	145	100%	[15]
Solar Photovoltaic (PV)	2,180	1,320	1,140	22	100%	[15]
Concentrated solar power (CSP)	5,050	5,050	5,050	180	100%	[15]
Solar (Off-grid)	2,580	1,580	1,360	26	100%	[15]
High-voltage direct current interconnection (HVDC)	1,000	1,000	1,000	1	52%	[25–27]
Hydro (large-scale)	2,100	2,100	2,100	55	100%	[15]
Hydro (small, <1 MW)	3,300	3,300	3,300	65	100%	[15]
Lead-acid battery	1,000	1,000	1,000	1	-	[15,28]
Direct air carbon capture and storage (DACCS-CE)	28,250	28,250	28,250	100	-	[29]
Direct air carbon capture and storage (DACCS-CW)	16,890	16,890	16,890	200	-	[30,31]

Supplementary Note 6: Regional wind, solar and hydro resources

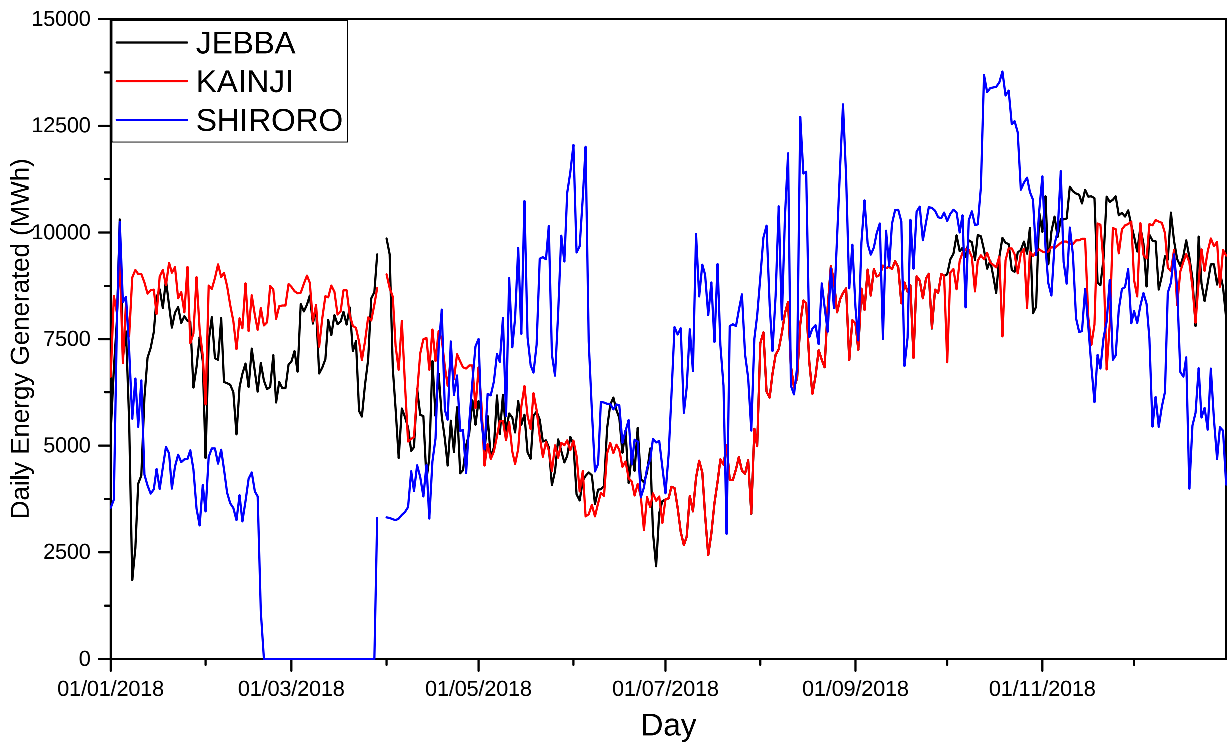
The spatial and temporal variation in the capacity factors of wind, solar and hydro power were considered in the ESONE model. Hydro availability was calculated based on the daily generation profiles of the three operational hydroelectric power stations in the country: Kainji, Shiroro and Jebba dams, all located in Niger state. Fig. 5 illustrates their seasonal variations in power output in 2018. The availability factor was calculated by daily peak generation for the year by the daily generation. Hourly availability of wind and solar were obtained from *Renewables ninja*, a tool which uses weather data from global reanalysis models and satellite observations to simulate the output of wind and solar power plants[6,10–13].

Nigeria is made up of 36 states and the Federal Capital Territory. These are further subdivided into 774 local government areas (LGAs). Owing to the diverse geography within states and thus varying weather/climate data, the hourly wind and solar availability were not obtained for a single location within each state. Instead, the availabilities were obtained for the 774 LGAs in 2018 to ensure higher-resolution data. For each state, the LGAs were ranked according to mean availability (highest to lowest). The average availability of the top third of LGAs was then calculated and used to represent the availability profile for the state. The hourly availability profiles were then clustered

Supplementary Table 3: Fuel costs inputs in the ESONE Nigeria model

Fuel	Scenario	Fuel Cost ($/MWh)				Data sources
		2020	2030	2040	2050	
Natural gas	Low Central High	10.24 13.0 23.88	10.24 13.0 23.88	10.24 13.0 23.88	10.24 13.0 23.88	[17,32]
Biomass	Low Central High	4.0 6.04 22.0	4.0 7.75 22.0	4.0 8.98 22.0	4.0 9.91 22.0	[32,33]
Coal		17.4	17.4	17.4	17.4	[32,33]
Diesel		62.2	62.2	62.2	62.2	[17,33]
Uranium (UO_2) fuel		2.9	2.9	2.9	2.9	[33]

using the k-means clustering algorithm described in Section .



Supplementary Figure 5: Power generated daily by Nigeria's three hydroelectric power stations: Jebba, Kainji and Shiroro dams

Supplementary Note 7: Data clustering

The ESONE model was selected for its ability to determine both optimal capacity expansion (on a multiyear timescale) and electricity dispatch (on an hourly timescale). For ease of model computation, temporal data implemented in the model (electricity demand, import prices, and wind, solar and hydro availabilities) were clustered using the k-means clustering algorithm. The algorithm is an iterative one which seeks to partition a dataset into distinct sub-groups where each data point belongs to only one group. Data points are assigned to a cluster such that the sum of the squared distance between the data points and the cluster's centroid (arithmetic mean of all data points in that cluster) is minimised.

The algorithm was used to determine a number, n, of representative days ("clusters") for each temporal data parameter. The clustering algorithm was implemented in R[34] as follows:

1. Collate hourly resolution data for all temporal parameters (electricity demand, electricity import prices, and solar, onshore wind, offshore wind and hydro availabilities). Data sources for each parameter are detailed in Sections and .

2. Divide the collated dataset into days. This sets the cluster size to 24 hours. For the ESONE model, the clustering algorithm was applied to zone-specific parameters (37 zones were used to represent Nigeria).

3. Extract the days with the peak values for each parameter. These will be the $(n+1)^{\text{th}}$ representative days with an assigned weighting factor of 1.

4. Normalise the electricity demand and import prices parameters so that the values are between 0 and 1. Availabilities are already normalised.

5. Specify the number of clusters, n, which is 10 for the analyses presented in this study[35,36]. This value was selected based on previous work with the model which assessed incurred errors due to data clustering[37–39]. The ESONE model was run with full temporal resolution (8760 hours), and then with data clustered into 20 and 10 representative days. It was found that using 10 clusters reduced the computational time significantly—solve time was reduced to 1-12 hours for the ESONE model. For non-technology specific variables (optimised total costs and capacity installed), clustering resulted in an accuracy loss of -6% to 0% relative to the full resolution case, which was considered to be acceptable for the increased ease of computation.

6. Apply the k-means clustering algorithm to the collated multidimensional data set. This preserves the hourly and zonal correlation between the parameters. Each daily profile will now be allocated to a cluster.

7. For each parameter, extract the n representative days given by the final iteration of the algorithm and their corresponding weighting factors.

8. Add the $(n+1)^{\text{th}}$ representative day determined in Step 3.

Supplementary Note 8: Model implementation

The ESONE-Nigeria model was implemented in GAMS 25.0.3 and solved using CPLEX 12.8.0 solver on a x86_64 machine using 24 threads.

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