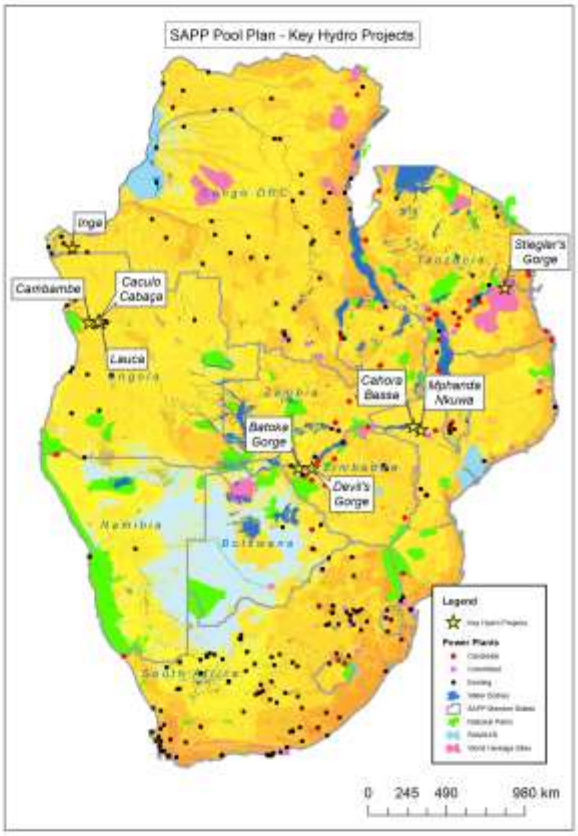
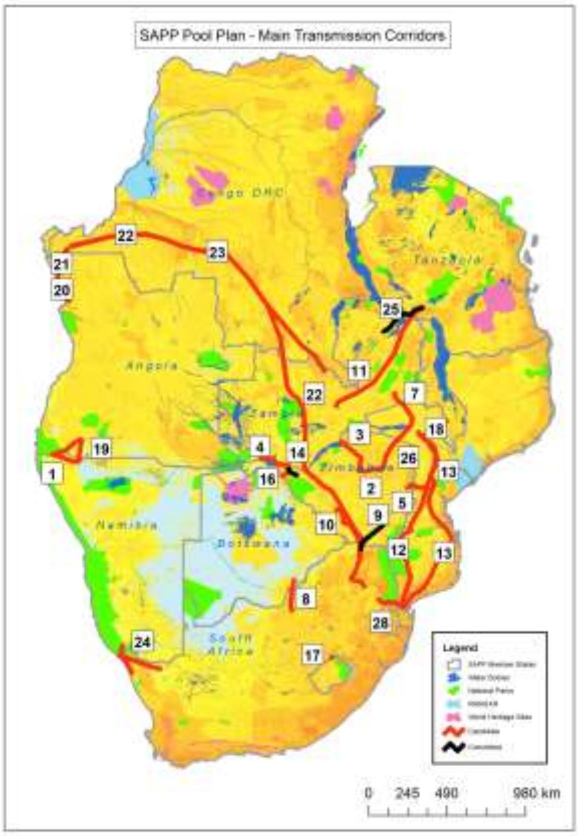
SAPP POOL PLAN 2017





Annex Volume

December 2017

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Abbreviations and acronyms

General

aag	Annual average growth
ACEC	Africa Clean Energy Corridor
ad	After diversity
BC	Basse Chute (Inga 3)
BCR	Benefit:cost ratio
BOSA	Botswana-South Africa interconnector
CC	Coordination Centre
CCGT	Combined cycle gas turbine
CRIDF	Climate Resilient Infrastructure Development Facility
CSP	Concentrating Solar Power
DAM	Day Ahead Market
DRC	Democratic Republic of the Congo
E&S	Environmental and Social
EAPP	East African Power Pool
ECA	Economic Consulting Associates
EE	Energy Exemplar
EEDSM	Energy efficiency demand side management
EIRR	Economic internal rate of return
ENS	Energy Not Served
ESC	Environment Sub-Committee of SAPP
FOR	Forced Outage Rate
GDP	Gross Domestic Product
GIS	Geographic Information System
HC	Haute Chute (Inga 3)
HDI	Human Development Index
HFO	Heavy fuel oil
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IGCC	Integrated Gasification Combined Cycle
IEA	International Energy Agency

IMF	International Monetary Fund
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
IRP	Integrated Resources Plan
JICA	Japan International Cooperation Agency
KZN	Kwazulu Natal
LDC	Load Duration Curve
LEAP	Long-range Energy Alternatives Planning
LNG	Liquified natural gas
LOLE	Loss of load expectation
LOLP	Loss of load probability
LT	Long-term
MINEA	Ministério da Energia e Agua (Angola)
MOTRACO	Mozambique Transmission Company
MOZISA	Mozambique-Zimbabwe-South Africa transmission line
MS	Microsoft
MT	Medium-term
NPV	Net present value
OCGT	Open cycle gas turbine
OPF	Optimum Power Flow
PAU	Project Acceleration Unit
PDAM	Post Day Ahead Market
PLEXOS	Generation and transmission optimal planning software
PPA	Power Purchase Agreement
PSC	Planning Sub-Committee of SAPP
PSMP	Power System Master Plan
PSS/E	Power System Simulator for Engineering (transmission planning software)
PV	Photovoltaic
REIPPPP	Renewable energy independent power producer procurement programme (South Africa)
RIAM	Rapid Impact Assessment Matrix
ROA	Real options analysis
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SCADA	Supervisory control and data acquisition

SDP	System Development plan
SRD	Social rate of discount
ST	Short-term
STE	Mozambique transmission project
SVC	Static VAR Compensator
TOR	Terms of Reference
UNDP	United Nations Development Program
(US)$	United States dollars
VO&M	Variable Operating and Maintenance
WACC	Weighted Average Cost of Capital
WEAP	Water Evaluation and Planning Model
ZIZABONA	Zimbabwe-Zambia-Botswana-Namibia transmission line
ZRB	Zambezi River Basin

Utility acronyms

BPC	Botswana Power Corporation
CEC	Copperbelt Energy Corporation
EdM	Electricidade de Moçambique
ENE	Empresa Nacional de Electricidade (Angola)
ESCOM	Electricity Supply Corporation of Malawi
ESKOM	Eskom Holdings (South Africa)
HCB	Hydroeléctrica de Cahora Bassa
LEC	Lesotho Electricity Company
NAMPOWER	Namibia Power Corporation
RNT	Empresa Rede Nacional de Transporte de Electricidade (Angola)
SEC	Swaziland Electricity Company
SNEL	Société Nationale d'Electricite
TANESCO	Tanzania Electricity Supply Company Ltd
ZESCO	ZESCO Limited (Zambia)
ZETDC	Zimbabwe Electricity Transmission & Distribution Company
ZESA	Zimbabwe Electricity Supply Authority

A1 Demand Forecast Report

The overall approach to demand forecasting is given in the Main Volume, Section 2.2. The purpose of this annex is to provide the country-specific details of the forecast methodology and the final projections which have been adopted. The annex is an update of the National Electricity Demand Forecasts (Section 2) of the Demand Forecast Report presented in September 2016.

A1.1 Angola

A1.1.1 Load forecast information supplied by the utility

The national electricity demand forecast in Angola is included in the 'List of Modelling Assumptions for the Angola Transmission System Demand Study', made by the transmission company, Empresa Rede Nacional de Transporte de Electricidade (RNT) and dated February 2016. The national electricity demand forecast includes the energy and the peak demand forecast of the country covering the period 2017-2025. A summary of the national electricity demand forecast and available relevant data are presented in Table 1. The review of the demand forecast is presented in Section A1.1.2 and the updated demand forecast which will be used in the SAPP pool plan is presented in Section A1.1.3.

Table 1 Angola's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*						
Country's demand forecast		2017	2020	2025	2030	2035	2040
	Peak demand (MW)						
	North	1,792	2,262	3,144	-	-	-
	Central	434	781	1,405	-	-	-
	South	345	531	845	-	-	-
	Energy demand (GWh)						
	Agg North	19,157	26,475	45,568	-	-	-
	Agg Central	1,408	2,367	4,147	-	-	-
	Agg South	942	1,642	2,908	-	-	-
Forecast period	The forecasting period of the national electricity demand forecast is 2017-2025.						
Methodology used	The forecast is modelled in PARAMOD (time series projection) according to the typical day-year hourly loads from each substation						
Forecasting parameters	No parameters are disclosed; forecast was modelled in PARAMOD using substation data.						
Main drivers	Unserved load and organic growth drive the growth.						

Source: Summary of information from RNT

A1.1.2 Review of utility's demand forecast

National demand forecast

The national electricity demand forecast of Angola was developed for the period 2017-2025 and provides energy and power demand forecasts for the three transmission systems in Angola. Energy demand was forecasted by substation but has been aggregated by transmission systems in Table 2. The three biggest substations are: Cazenga, Cab. Elevadora and Cambutas. Cazenga and Cab. Elevadora serve Luanda while no explanation is given for Cambutas, even though it comes online in 2017 and during the forecasting period, grows to represent a load of 19,910 GWh in 2025.

Table 2 Angola's demand forecast 2017-2025

	Energy demand [GWh]			Peak Loads [MW]		
	Agg Centre	Agg Norte	Agg South	Central	North	South
2015	793	6,438	559	299	1,507	161
2016	1,192	9,319	725	342	1,645	204
2017	1,408	19,157	942	434	1,792	345
2018	1,634	21,289	1,138	552	1,944	418
2019	2,035	23,744	1,319	656	2,100	477
2020	2,367	26,475	1,642	781	2,262	531
2021	2,681	29,519	1,857	886	2,428	587
2022	3,022	32,923	2,083	1,003	2,600	646
2023	3,375	36,736	2,321	1,139	2,776	709
2024	3,759	40,977	2,566	1,269	2,958	775
2025	4,147	45,568	2,908	1,405	3,144	845

Source: RNT, February 2016

The forecast takes into account the large unserved load present in Angola. It takes into account electrification of unserved areas and increase in organic growth from load shedding. As a response to the unserved load, the forecast shows an annual peak demand growth of 12% through 2025 which then lowers to 8% per year.

Forecasting methodology

The report in which the forecast was presented gives limited information on the methodology. The report is dated in February 2016 and the latest data used for the modelling is from December 2015.

The aggregate loads were estimated by gathering data at substations where available and modelled in PROMOD. This is a chronological model so monthly and annual energy was calculated as the sum of these hourly demands over the appropriate number of hours.

In the cases where parts of the substation data were missing it was extrapolated from available data and adjusted for the peak months of December and January.

Parameters used in the demand forecast

The parameters used for the national demand forecast were not provided.

The forecast assumes all three systems will be interconnected by 2018.

Comments on the demand forecast

There are major discrepancies between the energy demand figures and peak load figures provided. Analysing the load factor between aggregate energy sales and aggregate peak demand gives a value of 1.11 in the year 2025 (52,623/(5,394*8.76). Even allowing diversity between the demands on the three systems, it seems unlikely that the peak demands will be this high. After communicating with RNT members a different approach was agreed upon:

- A load factor of 65% was assumed for the forecasting period.
- The peak demand forecast was assumed to be the most representative of the two forecasts. Energy sent out was calculated using the assumed load factor and the peak demand forecast.
- No coincident factor was provided for the three systems. When national peak demand was calculated, a coincident factor of 0.85 was assumed.

No losses (technical or non-technical) were presented in the report. After communicating with RNT members, 20% loss rate was assumed for the forecasting period to convert final demand to sent out figures

Angola has three major electric systems, which are currently not inter-connected. The national forecast provided assumes interconnection between the three grids to be completed in 2017 for North-Central interconnection, and 2018 for Central-South interconnection. We have received information that a more conservative view would be to assume a completion of the Central-South interconnection in 2020. We will therefore use 2020 as the year the three systems interconnect.

RNT has confirmed that no committed exports are foreseen during the forecasting period.

Load shedding and other unserved load is accounted for in the forecast. A growth rate of 12% is given but not disaggregated any further. The proportion of organic growth, electrification of unserved areas or suppressed demand is not provided.

The forecast provided only reached 2025. To extend the forecast to 2040 the Central and South systems were assumed to grow until 2030 at the same rate as they did during the period 2020-2025, 12.5% p.a. and 9.7% p.a., respectively. During the period 2030-2040 a lower growth rate of 8% was assumed. For the North system the growth rate of the period 2020-2025, 6.8% p.a., was used to extend the demand forecast until 2040.

A1.1.3 Updates to base forecast and assumptions for low forecast

The national electricity demand forecast of Angola was extended to 2040 to cover the planning period of the SAPP pool plan. Since the national transmission grid will not be interconnected until 2020 we have only included years where some interconnection occurs. The period 2017-2019 in Table 3 will only include figures from North and Central Systems. From 2020-2040 all three systems will be interconnected and presented in the table below.

The 'low' demand forecast is based on an assumption of lower economic growth arising from continuation of low petroleum prices and a slow-down in the pace of infrastructural investment in the country. The annual average rate of growth in maximum demand in the base demand forecast is 7.7% per annum. In the low forecast, this is reduced to 3.4% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 3. The corresponding figures for the low forecast are given in Table 4. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 3 Angola's updated base electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)[1]
2015	-	-	-	9,105	*1,599*	-
2016	-	-	-	8,556	*1,503*	-
2017	7,922	0	20%	9,507	1,670	65%
2018	8,884	0	20%	10,661	1,872	65%
2019	9,806	0	20%	11,768	2,067	65%
2020	*10,828*	*0*	*20%*	12,994	2,282	65%
2021	*11,794*	*0*	*20%*	14,152	2,486	65%
2022	*12,821*	*0*	*20%*	15,385	2,702	65%
2023	*13,932*	*0*	*20%*	16,718	2,936	65%
2024	*15,042*	*0*	*20%*	18,051	3,170	65%
2025	*16,189*	*0*	*20%*	19,427	3,412	65%
2026	*17,574*	*0*	*20%*	21,089	3,704	65%
2027	*19,089*	*0*	*20%*	22,906	4,023	65%
2028	*20,746*	*0*	*20%*	24,895	4,372	65%
2029	*22,561*	*0*	*20%*	27,073	4,755	65%
2030	*24,191*	*0*	*20%*	29,029	5,098	65%
2031	*25,940*	*0*	*20%*	31,128	5,467	65%
2032	*27,816*	*0*	*20%*	33,379	5,862	65%
2033	*29,828*	*0*	*20%*	35,794	6,286	65%
2034	*31,987*	*0*	*20%*	38,385	6,741	65%
2035	*34,303*	*0*	*20%*	41,164	7,229	65%
2036	*36,788*	*0*	*20%*	44,146	7,753	65%
2037	*39,454*	*0*	*20%*	47,345	8,315	65%
2038	*42,315*	*0*	*20%*	50,778	8,918	65%
2039	*45,384*	*0*	*20%*	54,461	9,565	65%
2040	*48,678*	*0*	*20%*	58,413	10,259	65%
AAG	7.8%	-	-	13.2%	7.7%	-

Source: RNT, February 2016 Losses refer to technical and non-technical.

[1] The Load Factor is calculated by using *Peak demand sent out* and *Energy sent out*.

Table 4 Angola's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*9,105*	*1,599*	*8,541*	*1,500*
2016	*8,556*	*1,503*	*8,558*	*1,503*
2017	9,507	1,670	8,565	1,504
2018	10,661	1,872	8,978	1,577
2019	11,768	2,067	9,452	1,660
2020	12,994	2,282	9,879	1,735
2021	14,152	2,486	10,325	1,813
2022	15,385	2,702	10,725	1,884
2023	16,718	2,936	11,131	1,955
2024	18,051	3,170	11,551	2,029
2025	19,427	3,412	11,951	2,099
2026	21,089	3,704	12,347	2,168
2027	22,906	4,023	12,806	2,249
2028	24,895	4,372	13,286	2,333
2029	27,073	4,755	13,788	2,421
2030	29,029	5,098	14,312	2,514
2031	31,128	5,467	14,762	2,593
2032	33,379	5,862	15,226	2,674
2033	35,794	6,286	15,704	2,758
2034	38,385	6,741	16,198	2,845
2035	41,164	7,229	16,708	2,934
2036	44,146	7,753	17,234	3,027
2037	47,345	8,315	17,777	3,122
2038	50,778	8,918	18,337	3,220
2039	54,461	9,565	18,915	3,322
2040	58,413	10,259	19,512	3,427
AAG	13.2%	7.7%	3.4%	3.4%

Source: RNT, February 2016. Losses refer to technical and non-technical.

A1.2 Botswana

A1.2.1 Load forecast information supplied by the utility

The national electricity demand forecast in Botswana was submitted by Botswana Power Corporation in an Excel file named 'Botswana Forecast Information – 01062015' and through a document named 'Botswana Electricity Demand Forecast - Final Report 0.3'[2]. The national electricity demand forecast was developed in 2012 and the base year of the demand forecast is 2010. Three scenarios were developed for the period 2010-2031; the 'Low', the 'Likely' and the 'High' cases. Table 5 below summarises the national electricity demand forecast in Botswana from 2015 and comments on the forecasting methodology follow. The review of the national demand forecast in Botswana is presented in SectionA1.2.2 and the updated electricity demand forecast of Botswana that will be used in the SAPP pool development plan is presented in Section 2.2.3.

Table 5 Botswana's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*						
Country's demand forecast	**Power (MW)**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
	Low	621	754	836	879	-	-
	Likely	711	902	1,017	1,078	-	-
	High	796	1,053	1,208	1,289	-	-
	Energy (GWh)	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
	Low	3,625	4,308	4,720	4,911	-	-
	Likely	4,129	5,134	5,750	6,003	-	-
	High	4,661	6,015	6,870	7,214	-	-
Forecast period	The demand forecast was developed in 2012 and it covers the period 2010-2031. The base year of the demand forecast is 2010.						
Methodology used	The demand forecast is based on the predicted spatial location of future load, guided by aspects such as the Urban and District Development Plans, predicted future developments as well as the socio-economic perspective of Botswana. The following three forecast methods, each having its own approach applicable to the customer sector, were used: Spatial Forecast based on existing land-use and predicted future land-use; Point Load forecasts done for areas where information regarding Bulk and Large Power Users were available; Household forecast done for typical electrification areas. The household forecast models the load growth of individual households within a village and is especially useful for electrification type loads where the number of new households to be connected to the network is known for each year. System losses were not described in the demand forecast and the forecast does not include exports.						
Forecasting parameters	The data does not mention which parameters are used in the forecast.						

[2] An updated set of MW forecasts was provided on 24 August, but there were some difficulties with these numbers and there has not been sufficient opportunity to work through the issues in time for this report.

Item	Demand forecast information provided by utility – *final version in last sub-section*
Main drivers	The mining and the residential sectors activity contribute 35% and 31% to the total demand, respectively.

Source: Summary of information from BPC

A1.2.2 Review of utility's demand forecast

National demand forecast

The national electricity demand forecast in Botswana was developed in 2012 and the forecast period is 2010-2031. The base year of the demand forecast is 2010. Table 6 presents the national energy and peak demand forecast. The national demand forecast does not include electricity exports and does not show system losses. Three scenarios were developed for the demand forecast; the High scenario, the Likely scenario and the Low scenario. It is predicted that the electricity peak demand will grow from 553 MW in 2010 to 887 MW in the Low case scenario, a value of 1,091 MW in the Likely case scenario and 1,305 MW in the High case scenario by 2031. The average growth rate per annum over the period of 20 years for the low, likely and high scenarios are 3%, 4% and 5% respectively. The total energy consumption for 2010 amounted to 3,151 GWh. It is expected that by 2031 the energy demand will be 6,055 GWh in the most Likely scenario, 7,279 GWh in the High case scenario and 4,948 GWh in the Low scenario.

Table 6 Botswana's electricity demand forecast

		Power (MW)			**Energy (GWh)**			**Load factor (%)**		
		Low	**Likely**	**High**	**Low**	**Likely**	**High**	**Low**	**Likely**	**High**
		Low	Likely	High	Low	Likely	High	Low	Likely	High
Actual	2007	473	473	473	2,777	2,777	2,777	67%	67%	67%
Actual	2008	493	493	493	2,889	2,889	2,889	67%	67%	67%
Actual	2009	503	503	503	2,917	2,917	2,917	66%	66%	66%
Actual	2010	553	553	553	3,151	3,151	3,151	65%	65%	65%
Forecast	2011	556	571	586	3,157	3,229	3,301	65%	65%	64%
Forecast	2012	564	580	614	3,256	3,620	3,570	66%	71%	66%
Forecast	2013	578	644	713	3,432	3,804	4,198	68%	67%	67%
Forecast	2014	601	681	757	3,536	3,982	4,426	67%	67%	67%
Forecast	2015	621	711	796	3,625	4,129	4,661	67%	66%	67%
Forecast	2016	639	744	848	3,700	4,296	4,892	66%	66%	66%
Forecast	2017	660	773	911	3,798	4,428	5,248	66%	65%	66%
Forecast	2018	706	854	991	4,052	4,909	5,702	66%	66%	66%
Forecast	2019	722	877	1,020	4,116	5,009	5,840	65%	65%	65%
Forecast	2020	754	902	1,053	4,308	5,134	6,015	65%	65%	65%
Forecast	2021	770	924	1,081	4,382	5,241	6,158	65%	65%	65%

		Power (MW)			Energy (GWh)			Load factor (%)		
		Low	Likely	High	Low	Likely	High	Low	Likely	High
Forecast	2022	783	941	1,106	4,445	5,320	6,230	65%	65%	64%
Forecast	2023	795	959	1,171	4,485	5,391	6,697	64%	64%	65%
Forecast	2024	805	1,003	1,190	4,528	5,660	6,790	64%	64%	65%
Forecast	2025	836	1,017	1,208	4,720	5,750	6,870	64%	65%	65%
Forecast	2026	845	1,030	1,225	4,757	5,781	6,941	64%	64%	65%
Forecast	2027	854	1,042	1,242	4,797	5,840	7,012	64%	64%	64%
Forecast	2028	863	1,055	1,258	4,836	5,898	7,083	64%	64%	64%
Forecast	2029	870	1,067	1,274	4,873	5,950	7,148	64%	64%	64%
Forecast	2030	879	1,078	1,289	4,911	6,003	7,214	64%	64%	64%
Forecast	2031	887	1,091	1,305	4,948	6,055	7,279	64%	63%	64%

Source: BPC, 2012

Forecasting methodology

The forecast in Botswana is based on the predicted spatial location of future loads, guided by aspects such as the Urban and District Development Plans, predicted future developments as well as the socio-economic perspective of Botswana. Initially, the demand forecast looks at the loads of major development projects by spatial area. Then, for each customer type, a socio-economic analysis in relation to electricity load is conducted to estimate the forecast load of residential, commercial, agriculture and industrial users.

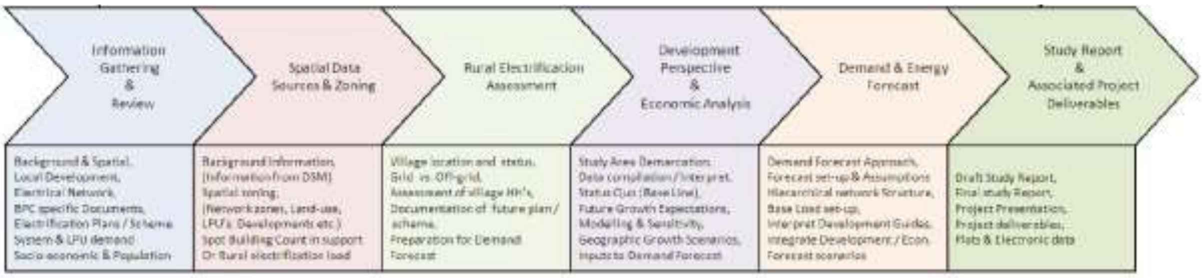
The spatial forecast is based on existing land-use and predicted future land-use. The spatial areas identified by the Department of Town and Regional planning were subdivided into small homogenous land use areas called load zones. The spatial forecasts for each zone utilised the base year load as obtained from network measurements and then forecasted the homogeneous areas load from the base year value according to the growth curve specified for the customer type.

The point load forecasts were developed for areas where information regarding large/bulk power users was available. The forecast was based on the trend of historical information or specific plant or customer extensions and projections. This forecast was mainly done for large mine loads and projects such as the Zambezi Integrated Agricultural Development Project.

The household forecasts were developed for typical electrification areas. The household forecast models the load growth of individual households within a village and is especially useful for electrification type loads where the number of new households to be connected to the network is known for each year. The households added each year start at year 0 on the individual growth curve and its contribution is added to those of other households which have progressed further along the growth curve as they were connected. This forecast method utilises a per unit curve, specified in the forecast sub-class, together with saturation After Diversity Maximum Demand (ADMD) per household values for various scenarios.

The detailed process which was followed by BPC for the development of the electricity demand forecast is explained in Figure below.

Figure 1 Botswana's electricity demand forecast process



Source: Electricity Demand Forecast, BPC, 2012

Parameters used in the demand forecast

The demand of the major development projects in Botswana is based on an analysis of the expected loads from major infrastructure developments, the existing and future mine developments and the major manufacturing developments. The existing and forecast load from those projects are depicted in Table 7 below.

Table 7 Electricity demand of major development projects (MVA)

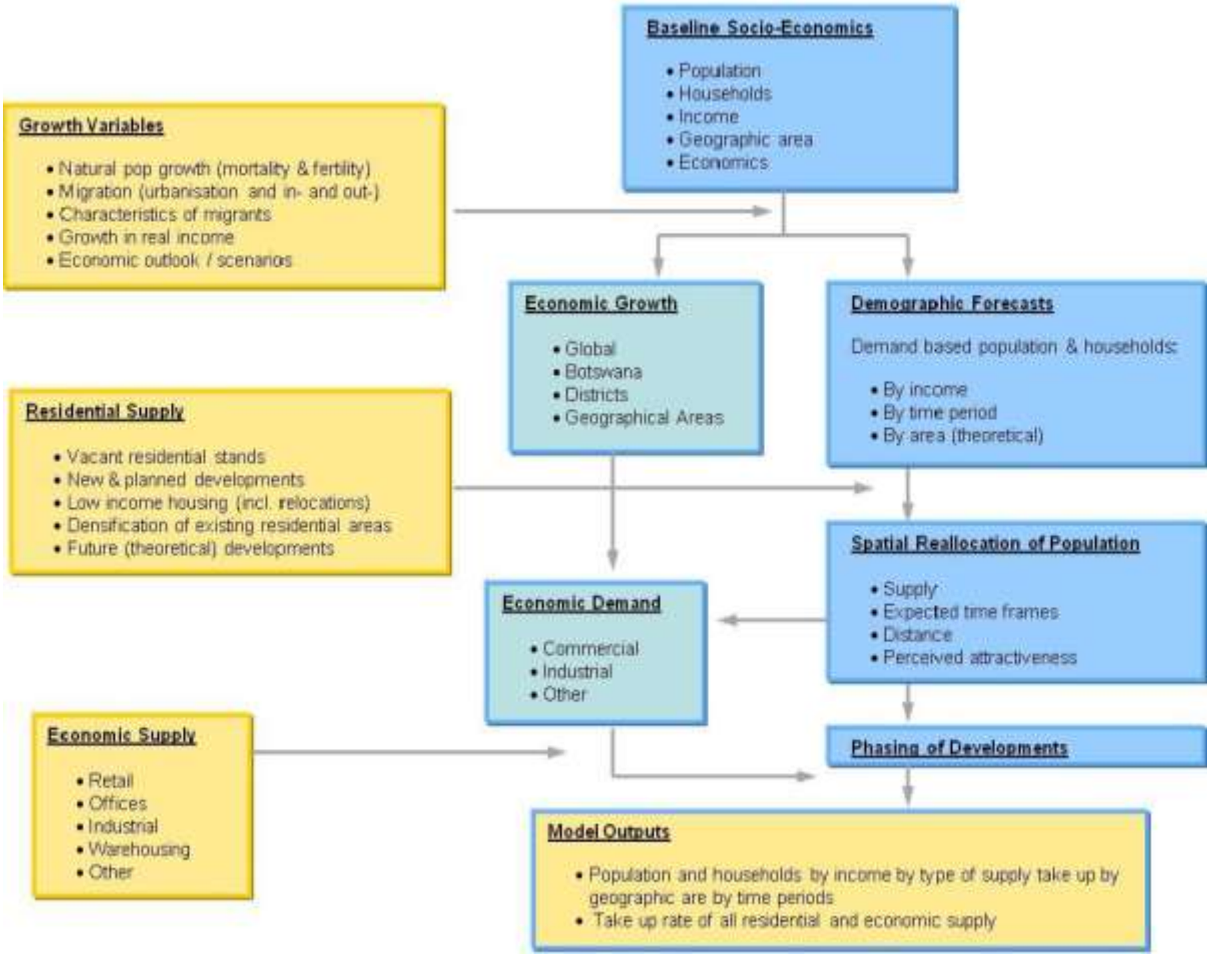
	Forecast demand from the ZAID projects			**Forecast demand from existing and proposed mines**			**Total demand from major development projects**		
	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
2010	0	0	0	187	187	187	187	187	187
2011	0	0	0	210	204	199	210	204	199
2012	0	0	0	284	244	205	284	244	205
2013	0	0	0	301	259	217	301	259	217
2014	0	0	0	312	268	221	312	268	221
2015	0	0	0	341	282	223	341	282	223
2016	43	0	0	352	291	230	395	291	230
2017	49	33	0	413	340	266	462	373	266
2018	55	36	0	415	341	268	470	377	268
2019	61	39	27	421	346	271	482	385	298
2020	66	42	28	427	351	275	493	393	303
2021	71	45	30	-	-	-	-	-	-
2022	158	47	32	-	-	-	-	-	-
2023	160	97	33	-	-	-	-	-	-
2024	163	100	69	-	-	-	-	-	-
2025	164	103	72	-	-	-	-	-	-

	Forecast demand from the ZAID projects			Forecast demand from existing and proposed mines			Total demand from major development projects		
	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
2027	167	109	77	-	-	-	-	-	-
2029	170	112	81	-	-	-	-	-	-
2031	170	114	84	-	-	-	-	-	-

Source: Electricity Demand Forecast, BPC, 2012

The demand from residential, commercial and other industrial users excluding the major development projects was based on a spatial analysis of socio-economic development. The parameters used for the demand forecast are depicted in Figure 2 below. The input parameters are highlighted in yellow colour and the calculated parameters that were used in the demand forecast are highlighted in blue colour.

Figure 2 Botswana's forecasting parameters



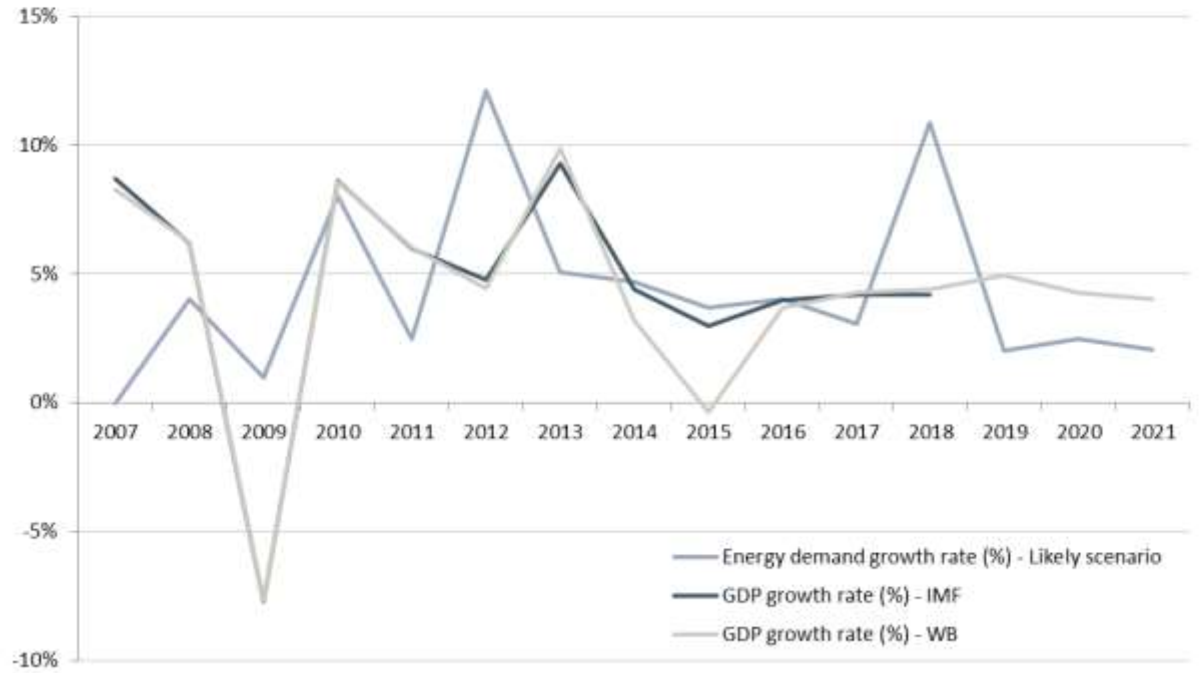
Source: Botswana Electricity Demand Forecast, 2012

Then assumed population growth rates which affect significantly the residential demand forecast were benchmarked against the population growth rate forecast developed by the World Bank. The average annual population growth rate that was used in the demand forecast was 1.3% and the average annual population growth rate developed by the World Bank for the next 30 years is 1.3%.

Comments on the demand forecast

Botswana's national electricity demand forecast aims to correlate the electricity demand with economic development. The national demand forecast was developed on a spatial basis trying to identify the load by region. Figure 3 below evaluates the performance of the model on a national basis by comparing the economic growth with the energy demand growth rate. The IMF's and World Bank's forecast GDP growth rates were compared with the energy demand growth rate of the national energy demand forecast. It is evident that the energy demand forecast that was derived from the spatial economic growth forecast is highly correlated to the national GDP growth rate forecast.

Figure 3 Botswana GDP growth rate and forecast



Source: BPC, 2012. IMF, 2016. WB, 2016

The national electricity demand forecast does not specifically show electricity system losses. Since no system losses have been provided we have assumed technical and non-technical losses to be 20%throughout the forecasting period and deducted the losses from the energy sent out to find energy sales.

An update on the energy demand forecast would be beneficial as it was made in 2012 and changes to external and internal variables could have an impact on the forecast. The forecast only reaches 2031. We have extrapolated the forecast using average growth rates for *peak demand sent out* and *energy sent out,* 1.2% p.a. and 0.9% p.a. respectively, for the period 2025-2031.

The demand forecast does not mention whether it includes demand side measures. The impact of such measures, such as implementing LED lightbulbs, could have a significant impact on household and commercial consumption and peak demand.

The forecast does not mention whether there has been suppressed demand/load shedding. However, scheduled installation of generation capacity suggests a positive reserve margin from the year 2017 and more than 27% reserve margin from the year 2019 onwards, it will be assumed that load shedding and suppressed demand will be at a minimum during the forecasting period.

A1.2.3 Updates to base forecast and assumptions for low forecast

The final demand forecasts used were based on a report prepared by Aurecon for BPC entitled *Botswana Electricity Demand Forecast Review.* It is dated August 2016, and was sent to the Pool Plan consultants after the December 2016 workshop.

The base forecast for the Pool Plan uses the 'likely' forecast from the Aurecon report, with a projection forward to 2040. The 'low' demand forecast is similarly extrapolated from the Aurecon 'low' scenario.

The annual average rate of growth in maximum demand in the base demand forecast is 3.5% per annum. In the low forecast, this is reduced to 3.1% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 8. The corresponding figures for the low forecast are given in Table 9. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 8 Botswana updated electricity demand forecast

Year	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)
2015	3,680	0	7.4%	3,974	606	75%
2016	3,686	0	7.4%	3,980	607	75%
2017	3,892	0	7.4%	4,203	641	75%
2018	4,147	0	7.4%	4,479	683	75%
2019	4,323	0	7.4%	4,669	712	75%
2020	5,006	0	7.4%	5,406	824	75%
2021	5,194	0	7.4%	5,609	855	75%
2022	5,553	0	7.4%	5,996	914	75%
2023	5,723	0	7.4%	6,180	942	75%
2024	5,899	0	7.4%	6,370	971	75%
2025	6,417	0	7.4%	6,930	1,057	75%
2026	6,581	0	7.4%	7,107	1,084	75%
2027	6,860	0	7.4%	7,408	1,130	75%
2028	6,963	0	7.4%	7,519	1,172	73%
2029	7,067	0	7.4%	7,632	1,187	73%
2030	7,214	0	7.4%	7,790	1,212	73%
2031	7,394	0	7.4%	7,985	1,234	74%
2032	7,579	0	7.4%	8,185	1,261	74%
2033	7,726	0	7.4%	8,344	1,286	74%
2034	7,788	0	7.4%	8,410	1,308	73%
2035	7,888	0	7.4%	8,518	1,325	73%
2036	8,052	0	7.4%	8,696	1,340	74%
2037	8,217	0	7.4%	8,874	1,365	74%
2038	8,367	0	7.4%	9,035	1,390	74%
2039	8,522	0	7.4%	9,203	1,413	74%
2040	8,683	0	7.4%	9,377	1,436	75%
AAG	3.5%	-	-	3.5%	3.5%	-

Source: BPC, 2012

Table 9 Botswana's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*3,974*	*606*	*3,974*	*606*
2016	*3,980*	*607*	*3,980*	*607*
2017	4,203	641	4,203	641
2018	4,479	683	4,479	683
2019	4,669	712	4,669	712
2020	5,406	824	4,879	744
2021	5,609	855	5,082	775
2022	5,996	914	5,469	834
2023	6,180	942	5,652	862
2024	6,370	971	5,842	891
2025	6,930	1,057	6,006	916
2026	7,107	1,084	6,183	943
2027	7,408	1,130	6,485	989
2028	7,519	1,172	6,582	1,030
2029	7,632	1,187	6,681	1,044
2030	7,790	1,212	6,856	1,071
2031	7,985	1,234	7,027	1,095
2032	8,185	1,261	7,203	1,119
2033	8,344	1,286	7,369	1,145
2034	8,410	1,308	7,428	1,168
2035	8,518	1,325	7,529	1,184
2036	8,696	1,340	7,701	1,198
2037	8,874	1,365	7,872	1,222
2038	9,035	1,390	8,027	1,246
2039	9,203	1,413	8,188	1,268
2040	9,377	1,436	8,356	1,291
AAG	3.5%	3.5%	3.0%	3.1%

Source: BPC, 2012

A1.3 Democratic Republic of Congo (DRC)

A1.3.1 Load forecast information supplied by the utility

The national electricity demand forecast in DRC was developed by SNEL in 2015 and it covers the period 2015-2030.Two relevant excel files were provided: the "Prévisions de la demande RDC 2010-2030.xlsx" including the power and the energy demand forecast of DRC disaggregated by region. The "Modèle demande_2016-05-02.xlsx" includes the power demand forecast model for the Kinshasa region. Table 8 summarises the national electricity demand forecast and comments on the methodology and the main drivers of the demand. The review of the national electricity demand forecast is presented in Section A1.3.2 and the updated electricity demand forecast which will be used in the 'SAPP Regional Generation and Transmission Expansion Plan' is presented in SectionA1.3.3.

Table 10 DRC's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*						
Country's demand forecast		2015	2020	2025	2030	2035	2040
	Energy (GWh)	15,177	20,681	26,529	33,573	-	-
	Power (MW)	2,542	3,464	4,444	5,624	-	-
Forecast period	The forecasting period is 2015-2030						
Methodology used	The forecast is disaggregated by regions and within each region by voltage levels of consumers; high voltage, medium voltage and low voltage. The low voltage consumption is further disaggregated by: Residential customers A, Residential customers B, Social customers and Commercial customers A bottom up approach is used for the low voltage customers. For medium and high voltage consumption a steady growth rate is assumed for the forecasting period.						
Forecasting parameters	The forecasting parameters for the low voltage consumption are demographic data (population growth by region, avg. size of households), electrification rates by region and avg. consumption of households.						
Main drivers	-						

Source: Summary of information from SNEL, 2016

A1.3.2 Review of utility's demand forecast

National demand forecast

The national electricity demand forecast in DRC was developed by SNEL and it covers the period 2010-2030. The base year of the demand forecast is 2015 and the estimated actual demand in 2015 was 1,956 MW. The power demand forecast grows at an average rate of 5.4% per annum to reach a level of 4,444 MW in 2030. The energy demand forecast is calculated from the peak demand forecast using an average load factor of 68% for all the years. Table 10 presents SNEL's national peak demand forecast disaggregated by region and Table presents SNEL's national energy demand forecast: this does not show the systems' technical and commercial losses and it does not include any provision for potential electricity exports.

Table 11 DRC's national peak demand forecast (MW)

Year	Region											
	Kinshasa	Bas-Congo	Bandundu	Kasai Occidental	Kasai Oriental	Katanga	Nord Kivu	Sud Kivu	Maniema	Oriental	Equateur	Total
2015	1,057	118	55	37	52	915	60	102	16	104	26	2,542
2016	1,175	122	57	38	54	975	63	105	17	107	27	2,735
2017	1,279	127	59	39	56	1,038	65	107	18	110	28	2,920
2018	1,387	133	61	40	59	1,106	68	110	20	113	30	3,114
2019	1,485	138	64	41	61	1,177	70	112	21	117	31	3,302
2020	1,552	144	66	42	63	1,254	73	115	22	120	33	3,464
2021	1,636	150	68	43	66	1,335	76	118	23	124	34	3,649
2022	1,697	156	71	44	68	1,422	79	121	25	128	36	3,816
2023	1,756	162	73	45	71	1,515	82	124	26	131	38	3,987
2024	1,901	169	76	46	74	1,613	86	127	28	135	40	4,251
2025	1,969	176	79	47	76	1,718	89	130	29	139	42	4,444
2026	2,058	183	81	49	79	1,830	93	133	31	144	44	4,665
2027	2,133	190	84	50	83	1,949	96	136	33	148	46	4,879
2028	2,239	198	87	51	86	2,075	100	139	35	152	48	5,133
2029	2,322	206	91	52	89	2,210	104	143	37	157	51	5,371
2030	2,410	215	94	54	93	2,354	108	146	39	162	53	5,624

Source: SNEL, 2016

Table 12 DRC's national energy demand forecast (GWh)

Year	Region											
	Kinshasa	Bas-Congo	Bandundu	Kasai Occidental	Kasai Oriental	Katanga	Nord Kivu	Sud Kivu	Maniema	Oriental	Equateur	Total
2015	6,310	701	330	221	311	5,464	359	611	98	619	152	15,177
2016	7,015	730	341	227	324	5,819	374	625	104	638	160	16,327
2017	7,636	760	354	232	336	6,197	389	640	110	657	168	17,432
2018	8,280	791	366	238	349	6,600	404	656	117	676	176	18,588
2019	8,865	824	380	244	363	7,029	420	672	124	697	185	19,712
2020	9,265	858	393	250	377	7,486	437	688	131	718	194	20,681
2021	9,767	893	407	257	392	7,972	455	704	139	739	204	21,783
2022	10,131	929	422	263	407	8,491	473	721	147	761	214	22,782
2023	10,483	967	437	269	423	9,042	492	738	156	784	225	23,804
2024	11,349	1,007	453	276	439	9,630	512	756	166	808	236	25,376

Year	Region											
	Kinshasa	Bas-Congo	Bandundu	Kasai Occidental	Kasai Oriental	Katanga	Nord Kivu	Sud Kivu	Maniema	Oriental	Equateur	Total
2025	11,755	1,048	469	283	457	10,256	532	774	176	832	248	26,529
2026	12,286	1,091	486	290	474	10,923	553	793	186	857	260	27,849
2027	12,734	1,136	504	297	493	11,633	575	812	197	883	273	29,129
2028	13,367	1,183	522	305	512	12,389	598	831	209	909	287	30,642
2029	13,862	1,231	541	313	532	13,194	622	851	222	936	302	32,066
2030	14,388	1,282	560	320	553	14,052	647	872	235	965	317	33,573

Source: SNEL, 2016

Forecasting methodology

The national electricity demand forecast in DRC is disaggregated by region and it covers the regions of Kinshasa, Bas-Congo, Bandundu, Kasai Occidental, Kasai Oriental, Katanga, Nord Kivu, Sud Kivu, Maniema, Oriental and Equateur. For each region the forecast is disaggregated by voltage level of supply covering the high voltage system, the medium voltage system and the low voltage system. The low voltage system's demand is further disaggregated to Residential customers A, Residential customers B, Social customers and Commercial customers.

The forecasting methodology which is used to estimate the load of the Residential customers A, Residential customers B and Social customers follows a bottom up end user approach. The load forecast of each category is calculated as the product of the number of households or commercial buildings of the category, the electrification rate and the average consumption per household or commercial building of the category. The population of Residential customers A, Residential customers B and Social Customers is calculated by disaggregating the regional annual population forecast. The portion of the population that is connected to the grid is assumed through the electrification rate. Finally, the average electricity demand per household or commercial building of Residential customers A, Residential customers B and Social customers is calculated based on the average electricity load of electric devices per household or commercial building (air condition, stove, coffee machines, iron, refrigerator, fridge, fan, radio and TV) and the average electricity load of lamps (incandescent lamps and florescent lamps) per household or commercial building.

The electricity demand forecast of Commercial customers connected to the low voltage system is assumed to be 25% of the total Residential customers A, Residential customers B and Social customers demand forecast.

The electricity demand forecast of the medium and the high voltage system is calculated as the product of the demand of the previous year and the assumed growth rate of the forecast year. The growth rate is entered as an exogenous parameter in the model. The starting point of the demand forecast is the actual demand of the base year.

The energy demand forecast is calculated from the peak demand forecast using the same load factor for all the forecast years.

The demand forecast methodology does not show the assumed system losses or the effect of demand side management measures.

Parameters used in the demand forecast

The demand forecast for the low voltage system uses the following exogenous parameters:

- The actual population for the base year by region
- The forecast population growth rate for the forecast years by region
- The average number of persons per household
- The electrification rate by region
- The split of the grid connected population by Residential customers A, Residential customers B and Social Customers.
- The average consumption per household for Residential customers A and Residential customers B; and the average consumption commercial building for Social customers.
- The assumed number of days per year.

Table 13below depicts the parameters used in the demand forecast of the low voltage system.

Table 13 DRC's low voltage forecast parameters

	Pop. growth rate (%)	Average pop. per household	Electrific ation rate	Split of connected households out of total			Average consumption per household(kWh/day)			Days per year
				Rés. A	Rés. B	Social	Rés. A	Rés. B	Social	
2015	0.0%	7.0	59.0%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2016	3.9%	6.9	61.0%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2017	3.9%	6.9	61.0%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2018	3.9%	6.8	61.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2019	3.9%	6.8	61.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2020	3.9%	6.8	61.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2021	3.9%	6.8	62.8%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2022	3.9%	6.8	63.0%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2023	3.9%	6.8	63.0%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2024	3.9%	6.6	64.7%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2025	3.9%	6.6	64.7%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2026	3.9%	6.6	65.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2027	3.9%	6.6	65.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360

	Pop. growth	Average pop. per	Electrification rate	Split of connected households out of total			Average consumption per household(kWh/day)			Days per
2028	3.9%	6.6	66.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2029	3.9%	6.6	66.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360
2030	3.9%	6.6	66.3%	13.3%	71.7%	15.0%	21.656	14.876	6.880	360

Source: SNEL, 2016

The assumed growth rate for the calculation of the demand in the medium voltage system is 4% from 2015 to 2025 and 5% from 2026 to 2030.

The actual data of 2014 which were used for the base year were not available.

Comments on the demand forecast

The national electricity demand forecast in DRC includes all the regions in DRC. However, only Bandubdu, Kinshasa, Katanga and bas Congo are interconnected. Therefore, the electricity demand forecast for the SAPP Pool development plan should include the coinciding demand only from these regions.

The population growth rate assumed in the demand forecast seems to be high in comparison to the World Bank and the IMF forecast. The expected growth rate of the population from the IMF is 3.0% for the next five years and the annual average forecast growth rate from the World bank for the next 20 years is 2.8%. In contrast, the annual average population growth rate that was used in the national demand forecast is 3.9%.

We did not receive any data on technical and non-technical losses of electricity. Based on the article '*The electricity supply industry in the Democratic Republic of the Congo*' by Lukamba-Muhiya and Uken we have assumed total losses (technical and non-technical) to be 40% in the year 2040. Although we have not received any information regarding loss prevention programs, in calculating the energy sales figures we have assumed losses to decline gradually to 20% over the forecasting period.

A1.3.3 Updates to base forecast and assumptions for low forecast

The forecast provided only reached 2030. We have extrapolated the *peak demand sent out* and *energy sent out* using the average growth rate from the period 2025-2030, 4.8% p.a. and 5.5% p.a., respectively.

The 'low' demand forecast is based on an assumption of lower economic growth arising from continuation of low mineral prices and a slow-down in the pace of electrification in the country. The annual average rate of growth in maximum demand in the base demand forecast is 5.2% per annum. In the low forecast, this is reduced to 3.8% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 14. The corresponding figures for the low forecast are given in Table 15. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 14 DRC's updated electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)
2015	7,499	0	40%	10,499	1,410	85%
2016	7,638	0	39%	10,632	1,517	80%
2017	7,689	0	38%	10,641	1,620	75%
2018	7,697	0	38%	10,592	1,727	70%
2019	7,975	0	37%	10,910	1,832	68%
2020	8,416	0	36%	11,445	1,921	68%
2021	8,918	0	35%	12,057	2,024	68%
2022	9,381	0	34%	12,609	2,117	68%
2023	9,860	0	34%	13,174	2,212	68%
2024	10,577	0	33%	14,046	2,358	68%
2025	11,124	0	32%	14,684	2,465	68%
2026	11,748	0	31%	15,414	2,588	68%
2027	12,363	0	30%	16,121	2,706	68%
2028	13,086	0	30%	16,960	2,847	68%
2029	13,778	0	29%	17,746	2,979	68%
2030	14,518	0	28%	18,582	3,120	68%
2031	15,539	0	27%	19,765	3,270	69%
2032	16,391	0	26%	20,718	3,428	69%
2033	17,291	0	26%	21,717	3,593	69%
2034	18,505	0	25%	23,094	3,766	70%
2035	19,523	0	24%	24,208	3,948	70%
2036	20,891	0	23%	25,738	4,138	71%
2037	22,042	0	22%	26,979	4,338	71%
2038	23,584	0	22%	28,679	4,547	72%
2039	24,886	0	21%	30,062	4,766	72%
2040	26,260	0	20%	31,511	4,996	72%
AAG	5.1%	-	-	4.5%	5.2%	-

Source: SNEL, 2016

Table 15 DRC's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*10,499*	*1,410*	*10,499*	*1,410*
2016	*10,632*	*1,517*	*10,069*	*1,437*
2017	10,641	1,620	9,931	1,512
2018	10,592	1,727	9,742	1,589
2019	10,910	1,832	9,903	1,663
2020	11,445	1,921	10,277	1,725
2021	12,057	2,024	10,699	1,796
2022	12,609	2,117	11,076	1,859
2023	13,174	2,212	11,458	1,924
2024	14,046	2,358	12,042	2,021
2025	14,684	2,465	12,462	2,092
2026	15,414	2,588	12,939	2,172
2027	16,121	2,706	13,395	2,249
2028	16,960	2,847	13,932	2,339
2029	17,746	2,979	14,429	2,422
2030	18,582	3,120	14,952	2,510
2031	19,765	3,270	15,734	2,603
2032	20,718	3,428	16,318	2,700
2033	21,717	3,593	16,923	2,800
2034	23,094	3,766	17,805	2,904
2035	24,208	3,948	18,466	3,011
2036	25,738	4,138	19,424	3,123
2037	26,979	4,338	20,145	3,239
2038	28,679	4,547	21,186	3,359
2039	30,062	4,766	21,972	3,484
2040	31,511	4,996	22,788	3,613
AAG	4.5%	5.2%	3.1%	3.8%

Source: SNEL, 2016

A1.4 Lesotho

A1.4.1 Load forecast information supplied by the utility

The national electricity demand forecast in Lesotho was developed by Lesotho Electricity Corporation (LEC) and it was submitted through 'Demand Forecast Model.xlsx' and the 'National Peak Load Projection.xlsx' files. The peak demand forecast was developed for the period 2015-2035 and the energy demand forecast covers the period 2012-2030.Table 16 provides a summary of the forecast, the forecast methodology, the forecasting parameters and the main drivers of the demand growth. Section A1.4.2 includes a review on the forecast and the updated electricity demand forecast which will be used in the 'SAPP Regional Generation and Transmission Expansion Plan' is presented in Section A1.4.3.

Table 16 Lesotho's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*											
Country's demand forecast	2015		2020		2025		2030		2035		2040	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
	177	706	238	914	272	1181	315	1482	343	-	-	-
Forecast period	The peak demand forecast covers the period 2015-2035 and the energy demand forecast covers 2013-2030											
Methodology used	The peak demand is disaggregated by system load, mining industry and electrification programmes. A hybrid approach is used where the electrification's bottom up approach is combined with organic growth and scheduled industry and mining increases. For the energy demand, an end-user approach is taken and econometric analysis used to model the growth. The forecast uses 2012 as the base year.											
Forecasting parameters	The peak load forecast uses a linear organic growth and new connection rates from electrification programmes. The energy demand uses GDP growth, income elasticity, price increase and price elasticity to estimate average consumption. Population growth and electrification rates are used to find the customer growth.											
Main drivers	Added demand from the mining industry drives the forecast and grows from 8% of total demand to 25% in 2035.											

Source: Summary of information from LEC

A1.4.2 Review of utility's demand forecast

National demand forecast

The national peak demand forecast in Lesotho was developed for the period 2015-2035 and uses as a base year the actual values of 2015. The national energy demand forecast was developed for the period 2012-2030 and uses for the base year the actual energy consumption of 2012. The national electricity demand forecast is presented in Table 17 together with the calculated annual load factors and annual growth rates. The average annual energy demand growth rate of the demand forecast is 5.1% and the average annual peak demand growth rate is 3.4%. Transmission and distribution system losses are not shown explicitly. Furthermore, the forecast does not mention whether suppressed demand was taken into account. The forecast does not include any exports.

Table 17 Lesotho's national electricity demand forecast

	Peak demand (MW)	Energy demand (GWh)	Load factor (%)	Peak demand growth rate (%)	Energy demand growth rate (%)
2015	177	706	46%	-	-
2016	196	740	43%	10.7%	4.8%
2017	218	774	41%	11.2%	4.6%
2018	223	819	42%	2.3%	5.8%
2019	230	864	43%	3.1%	5.5%
2020	238	914	44%	3.5%	5.8%
2021	244	962	45%	2.5%	5.3%
2022	251	1,015	46%	2.9%	5.5%
2023	261	1,069	47%	4.0%	5.3%
2024	267	1,124	48%	2.3%	5.1%
2025	271	1,181	50%	1.5%	5.1%
2026	279	1,238	51%	3.0%	4.8%
2027	290	1,297	51%	3.9%	4.8%
2028	295	1,357	53%	1.7%	4.6%
2029	309	1,419	52%	4.7%	4.6%
2030	314	1,482	54%	1.6%	4.4%
2031	319	1,515	54%	1.6%	2.2%
2032	324	1,558	55%	1.6%	2.8%
2033	329	1,591	55%	1.5%	2.1%
2034	336	1,648	56%	2.1%	3.5%
2035	342	1,690	55%	1.8%	2.5%

Source: LEC, 2016

Forecasting methodology

The peak demand forecast and the energy demand forecast were developed separately and each forecast uses a different methodology. A simple trend analysis is used to forecast the peak demand of the electricity system and a hybrid model is used to forecast the energy demand. The hybrid model combines an end user approach with econometric equations.

Peak demand forecast methodology

The peak demand forecast is disaggregated by the system's demand without big industrial projects, the demand from big industrial projects, the demand from the Government of Lesotho (GOL) electrification project and the demand from the Badea electrification project. The demand forecast of the above categories is then summed and weighted by diversity to form the national electricity peak demand forecast. Actual values for 2013, 2014 and 2015 were provided and 2015 was used as the base year of the demand forecast. A description of the forecast methodology of each category is provided below.

The system's load forecast without big industrial projects is divided into the demand supplied by Muela hydropower plant (MHP) and the demand above MHP's capacity. The demand from the MHP is assumed to be constant throughout the forecasting period. For the demand forecast above MHP, 2015 is set as a base year and an annual growth rate of 2.3% is set to forecast the load throughout the forecasting period.

The peak load of big industrial projects includes the demand from five mines (Letseng Diamond Mine, Kao mine, Liqhobonq mine, Lemphane mine and Mothae mine). The demand from big industrial projects is entered as a hardcoded number individually for each project based on the estimated annual demand of the project.

The forecast demand of the GOL electrification project is calculated by adding 2 MW of load each year. The forecast demand from the BADEA electrification project follows an end user approach. The forecast demand is calculated as the product of the electrification rate, the number of households and the average demand per household.

The peak demand forecast from Lesotho National Development Corporation (LNDC) was also calculated; however, it is not included in the national peak demand forecast.

The peak demand forecast methodology does not account separately for the suppressed demand and does not include any calculations for demand side measures. Technical and commercial losses are not shown explicitly.

Energy demand forecast methodology

The energy demand forecast is broken down by consumer sectors into domestic, general purpose, commercial LV, commercial MV, industrial LV, industrial MV and LHDA. Each consumer sector is further disaggregated to new connections and old connections. The demand forecasts of each consumer sector (both for new and old connections) are estimated using an end-user approach by multiplying the forecast number of customers of each consumer sector with the forecast average energy consumption of each sector. The base value of the average energy consumption per consumer per consumer sector is the actual average energy consumption per consumer per consumer sector of 2012. Then, an econometric equation is used to calculate the annual growth rate of the average energy consumption per consumer per consumer sector. The independent variables of the econometric equation include the GDP growth rate, the income levels and the electricity price. The calculated annual growth rate is then multiplied by the previous year's average energy consumption per consumer sector. The number of customers in each consumer sector is estimated through the forecast population growth rate. The base value of the number of customers per consumer sector is the actual number of customers per consumer sector of

2012. The base value is multiplied by the population growth rate to forecast the number of customers per consumer sector for the forecast years. The equations for the calculation of the energy demand forecast are described below, where i symbolises the customer sectors category and t the forecast year.

$$Energy\ demand_{i_t} = Average\ energy\ consumption\ per\ customer_{i_t} * Number\ of\ customers_{i_t}$$

$$Average\ consumption\ per\ customer_{i_t} = Average\ consumption\ per\ customer_{i_{t-1}} * Average\ consumption\ per\ customer\ growth\ rate_{i_t}$$

$$Average\ consumption\ per\ customer\ growth\ rate_{i_t} = (1 + GDP\ growth\ rate_t)^{Income\ elacticity} * (1 + Price\ increase_t)^{Price\ elacticity}$$

$$Number\ of\ customers_{i_t} = Number\ of\ customers_{i_t} * (1 + Popolation\ growth\ rate_{i_{t-1}})$$

The average energy consumption per customer for the base year of the forecast is calculated from the actual energy sales per customer and thus it does not appear to include transmission or distribution system losses. The forecast does not mention whether demand side measures are taken into account.

Parameters used in the demand forecast

The parameters used for the peak demand forecast are presented in Table 18below. The actual system load above MHP for 2015 was 90 MW. The forecast load from exceeding MHP's supply from 2016 to 2035 is calculated through an estimated annual growth rate of 2.3%.

Table 18 System load growth (Excl. mining & electrification programs)

	MHP load (MW)	Actual system load above MHP (MW)	Forecast annual growth rate of system's load above MHP (%)	System Load growth above MHP (MW)	Mining demand (MW)	GOL Electrification Load (MW)	BADEA Electrification Load (MW)	Total system Load (MW)
2015	72	90	-	-	14	1	0	177
2016	72	-	2.3%	93	28	3	1	197
2017	72	-	2.3%	95	46	5	1	219
2018	72	-	2.3%	97	47	7	1	224
2019	72	-	2.3%	99	50	9	0	230
2020	72	-	2.3%	101	54	11	0	238
2021	72	-	2.3%	104	56	13	0	245
2022	72	-	2.3%	106	58	15	0	251
2023	72	-	2.3%	109	64	17	0	261
2024	72	-	2.3%	111	65	19	0	267
2025	72	-	2.3%	114	65	21	0	272

	MHP load (MW)	Actual system load above MHP (MW)	Forecast annual growth rate of system's load above MHP (%)	System Load growth above MHP (MW)	Mining demand (MW)	GOL Electrification Load (MW)	BADEA Electrification Load (MW)	Total system Load (MW)
2026	72	-	2.3%	116	68	23	0	279
2027	72	-	2.3%	119	74	25	0	290
2028	72	-	2.3%	122	75	27	0	295
2029	72	-	2.3%	124	84	29	0	310
2030	72	-	2.3%	127	84	31	0	315
2031	72	-	2.3%	130	84	33	0	320
2032	72	-	2.3%	133	85	35	0	325
2033	72	-	2.3%	136	85	37	0	330
2034	72	-	2.3%	139	86	39	0	336
2035	72	-	2.3%	143	87	41	0	343

Source: LEC, 2016

The disaggregated forecast load from the operation of the mines is presented in Table. The demand from the mines is expected to increase within the forecasting period due to the commencement of new mining projects. The demand from the mines increases at an average growth rate of 11%per annum in comparison to 2015 levels.

Table 19 Demand from the mining industry (MW)

	Lets'eng Diamaond Mine load	LDM U/G decline	LDM U/G shaft	Kao Mine Load	Liqhobong Mine	Lemphane Mine	Mothae Mine	Total mining demand
2015	13	0	0	1	0	0	0	14
2016	13	0	0	9	6	0	0	28
2017	23	0	0	10	7	0	6	46
2018	23	0	0	11	7	0	6	47
2019	23	0	0	12	8	0	7	50
2020	23	0	0	13	8	3	7	54
2021	23	0	0	14	8	3	8	56
2022	23	0	0	15	8	4	8	58
2023	23	1	0	20	8	4	8	64
2024	23	1	0	20	8	5	8	65
2025	23	1	0	20	8	5	8	65
2026	23	3	0	20	8	6	8	68
2027	23	9	0	20	8	6	8	74
2028	23	2	8	20	8	6	8	75

	Lets'eng Diamaond Mine load	LDM U/G decline	LDM U/G shaft	Kao Mine Load	Liqhobong Mine	Lemphane Mine	Mothae Mine	Total mining demand
2029	23	12	8	20	8	6	8	84
2030	23	12	8	20	8	6	8	84
2031	23	12	8	20	8	6	8	84
2032	23	12	8	20	8	6	8	85
2033	23	12	8	20	8	6	8	85
2034	23	12	8	20	8	6	8	86
2035	23	12	8	21	8	6	8	87

Source: LEC, 2016

The parameters used for peak demand forecast of the electrification programs are listed in Table 20. The GOL program assumes that every year 3,000 new households will be connected to the grid with an average demand per household per annum of 0.8 kW. The assumed coincident load factor for the household demand is 50%. The same parameters were assumed for the BADEA electrification program, though the new connections per annum are organised around 7 lots.

Table 20 Parameters used for electrification programs

Electrification Program	Average demand per houshold per annum (kW)	Average new connections per annum		Electrification factor (%)	Coincident load factor for housholds	Average load per year (MW)
GOL program	0.8	3,000		1	0.5	1.2
BADEA program	0.8	Lot 1	2,266	0.9	0.5	0.8
		Lot 2	1,797	0.8		0.6
		Lot 3	1,095	0.9		0.4
		Lot 4	2,296	0.8		0.7
		Lot 5	1,541	1		0.6
		Lot 6	575	1		0.2
		Lot 7	150	0.9		0.1

Source: LEC, 2016

Energy demand forecast

The base year of the energy demand forecast was 2012. The actual average energy consumption per customer category in 2012 which was used as the starting point in the energy demand forecast is presented in Table 21. Table 22 presents the actual number of customers per consumer sector per region for 2012.

Table 21 Actual energy consumption per household (kWh/year)

	Domestic consumers	General purpose	Commercial LV	Commercial MV	Industrial LV	Industrial MV	LHDA
Average energy consumption per customer - old customer	2,127	11,949	323,433	1,641,364	276,332	4,521,497	6,409,709
Average energy consumption per customer - new customer	391	5,975	323,433	1,641,364	276,332	4,521,497	6,409,709

Source: LEC, 2016

Table 22 Number of customers per consumer's sector per region in 2012

	Domestic consumers	General purpose	Commercial LV	Commercial MV	Industrial LV	Industrial MV	LHDA
BOTHA-BOTHA	5,558	465	8	2	8	2	1
LERIBE	18,062	1,512	24	4	18	5	0
BEREA	15,283	1,279	21	4	18	5	0
MASERU	21,674	1,815	30	7	32	8	0
MAFETENG	10,281	861	14	3	14	4	0
MOHALE'S HOEK	10,281	861	14	3	13	3	0
QUTHING	7,503	628	10	2	9	2	0
QACHA'S NEK	3,890	326	5	1	5	1	0
MOKHOTLONG	5,835	489	8	2	7	2	0
THABA-TSEKA	5,835	605	10	2	10	2	0

Source: LEC, 2016

The average energy consumption growth rate per customer category per region for the forecast years is calculated through an econometric equation. The independent variables of the econometric equation include the GDP growth rate, the income levels and the electricity price. The independent variables that were used in the demand forecast are presented in Table 23 below. The income elasticity was assumed to be 0.3 and the price elasticity -0.25 only for the domestic consumers; the price elasticity for the other consumer sectors was 0. The population growth rate which was used to forecast the number of customers per consumer sector is also presented in Table 23.

Table 23 Independent variable of the econometric equation

	GDP growth rate per year (%)	Price increase per year (%)	Population growth rate per year (%)
2013	2	5	0.13
2014	5.5	0	0.13
2015	4	5	0.13
2016	4	0	0.15
2017	4	5	0.17
2018	4	0	0.2
2019	4	5	0.23
2020	3.5	0	0.26
2021	3.5	5	0.28
2022	3.5	0	0.3
2023	3.5	0	0.32
2024	3.5	0	0.35
2025	3.5	0	0.37
2026	3.5	0	0.4
2027	3.5	0	0.42
2028	3.5	0	0.44
2029	3.5	0	0.47
2030	3.5	0	0.5

Source: LEC, 2016

Comments on the demand forecast

The national peak demand forecast and the national energy demand forecast were developed separately. The energy demand forecast is based on energy sales and does neither include technical nor commercial losses. The peak demand forecast does not mention whether suppressed demand was taken into account and if it incorporates the effects from demand side measures.

Technical and commercial losses can make up a significant portion of the energy sent out. It is therefore necessary to get actual data on losses to complete Table 25. We request the latest data on technical losses and if any loss reduction programs are foreseen during the forecasting period. For now, we have assumed total losses (technical and non-technical) to be 20% throughout the entire forecasting period.

The parameters used in the econometric equation of the energy demand forecast are: GDP growth rate, income elasticity, price increase and price elasticity. The GDP growth rates used in the econometric equation of the energy demand forecast were compared with the IMF's GDP growth rate forecast. The average annual GDP growth rate from the IMF is 3.7% and the average annual GDP growth rate of the demand forecast is 3.7%.

The elasticities of the econometric equation of the energy demand forecast were assumed to be the same for all consumer sectors. The consumption characteristics of each consumer sector usually differ and this is usually reflected in the elasticities used to forecast electricity demand.

The forecast of the connections per consumer sector uses the population growth rate as an underlying parameter. The population growth rate that was used in the demand forecast is compared to population growth rate forecasts developed by other institutions in Table 24. A similarity is observed between the LEC's forecast data and the IMF forecast. However, the World Bank forecast is significantly higher.

Table 24 Population growth parameters [%]

	LEC Forecast	IMF – April'16	UN-WPP 2016
2013	0.1	0.2	1.3
2014	0.1	0.3	1.3
2015	0.1	0.3	1.2
2016	0.1	0.3	1.2
2017	0.1	0.3	1.2
2018	0.2	0.3	1.1
2019	0.2	0.3	1.1
2020	0.3	0.3	1.1
2021	0.3	0.3	1.1
2022	0.3	-	1
2023	0.3	-	1
2024	0.4	-	1
2025	0.4	-	1
2026	0.4	-	1
2027	0.4	-	0.9
2028	0.4	-	0.9
2029	0.5	-	0.9
2030	0.5	-	0.9

Source: IMF, 2016, WB, 2016; LEC, 2016

The annual contribution to the peak demand of the GOL electrification projects is calculated on a separate sheet in LEC's forecasting model and shows an annual contribution to the peak demand of 1.2 MW per year. However, the total national peak demand forecast assumes an annual contribution to the peak demand of 2 MW per year from the GOL electrification projects. The1 MW forecast load from the BADEA program is accounted for three years 2016 – 2018.

The forecasting methodology of the system's load is mainly based on trend line analysis. The linear growth rate for the forecast of the demand supplied above MHP's capacity was 2.3%.

The trend line analysis was not available and explanatory power of the linear growth rate that was used in LEC's forecasting model cannot be tested.

The estimated load from Lesotho National Development Corporation (LDNC) that was calculated in LEC's peak demand forecast model was not included in the forecast values of LEC's national peak demand forecast.

The two forecasts, energy demand and peak demand, are made separately from each other and variables such as electrification rates do not seem to be based on the same assumptions. For the peak demand forecast, two electrification programs are listed and about 57,000 new connections are planned for the period 2015-2030. However, for the total energy forecast 296,000 new domestic connections are planned for the same period. This discrepancy leads to significantly higher growth rate in energy demand than peak demand and a very high load factor near the end of the forecasting period (83% in 2040). In order to prevent this unlikely load factor, we have kept the load factor constant at its 2035 level, 74%, throughout the rest of the forecast. From the fixed load factor, we have adjusted our extrapolation of *energy sent out* to coincide with the 74% load factor and the extrapolation of *peak demand sent out*.

A1.4.3 Updates to base forecast and assumptions for low forecast

The forecasts provided did not extend the entire forecasting period. The energy sales forecast only reached 2030 and the peak demand forecast reached 2035. We have therefore extrapolated the peak demand forecast to 2040 using the average growth rate during the period 2025-2035, 2.4%. We extrapolated the *energy sales* forecast to 2035 using the average growth rate during the period 2025-2030, 4.6%. For the period 2036-2040 we found the *energy sent out* using the load factor (74%) and the extrapolated *peak demand sent out*. As mentioned in the comments above, losses (technical and non-technical) of 20% have been estimated throughout the forecasting period.

The 'low' demand forecast is based on an assumption of lower economic growth arising and a slow-down in the pace of electrification. The annual average rate of growth in maximum demand in the base demand forecast is 3.5% per annum. In the low forecast, this is reduced to 2.1% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 25. The corresponding figures for the low forecast are given in Table 26. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 25 Lesotho's updated electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)
2015	706	*0*	*13%*	645	135	55%
2016	740	*0*	*13%*	677	149	52%
2017	774	*0*	*13%*	706	166	49%
2018	819	*0*	*13%*	740	168	50%
2019	864	*0*	*13%*	774	172	51%
2020	914	*0*	*13%*	819	178	53%
2021	962	*0*	*13%*	864	183	54%
2022	1,015	*0*	*13%*	914	188	55%
2023	1,069	*0*	*13%*	962	196	56%
2024	1,124	*0*	*13%*	1,015	201	58%
2025	1,181	*0*	*13%*	1,069	204	60%
2026	1,238	*0*	*13%*	1,124	211	61%
2027	1,297	*0*	*13%*	1,181	220	61%
2028	1,357	*0*	*13%*	1,238	224	63%
2029	1,419	*0*	*13%*	1,297	235	63%
2030	1,482	*0*	*13%*	1,357	240	65%
2031	*1,551*	*0*	*13%*	1,420	243	67%
2032	*1,623*	*0*	*13%*	1,486	247	69%
2033	*1,698*	*0*	*13%*	1,556	251	71%
2034	*1,777*	*0*	*13%*	1,628	256	72%
2035	*1,860*	*0*	*13%*	1,703	261	74%
2036	*1,571*	*0*	*13%*	1,776	272	74%
2037	*1,638*	*0*	*13%*	1,851	284	74%
2038	*1,707*	*0*	*13%*	1,929	296	74%
2039	*1,780*	*0*	*13%*	2,011	308	74%
2040	*1,855*	*0*	*13%*	2,096	321	74%
AAG	3.9%	-	-	4.8%	3.5%	-

Source: LEC, 2016

Table 26 Lesotho's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*645*	*135*	*645*	*135*
2016	*677*	*149*	*681*	*150*
2017	706	166	793	186
2018	740	168	804	182
2019	774	172	822	182
2020	819	178	851	185
2021	864	183	874	185
2022	914	188	902	186
2023	962	196	937	191
2024	1,015	201	962	190
2025	1,069	204	979	187
2026	1,124	211	1,011	190
2027	1,181	220	1,053	196
2028	1,238	224	1,074	195
2029	1,297	235	1,127	204
2030	1,357	240	1,161	205
2031	1,420	243	1,195	205
2032	1,486	247	1,231	205
2033	1,556	251	1,271	205
2034	1,628	256	1,311	207
2035	1,703	261	1,351	207
2036	1,776	272	1,378	211
2037	1,851	284	1,405	215
2038	1,929	296	1,433	220
2039	2,011	308	1,462	224
2040	2,096	321	1,491	229
AAG	4.8%	3.5%	3.4%	2.1%

Source: LEC, 2016

A1.5 Malawi

A1.5.1 Load forecast information supplied by the utility

The national electricity demand forecast in Malawi was developed in 2015 by the Ministry of Natural Resources, Energy and Mining (MNREM)'s Department of Energy (DoE) and the Electricity Supply Corporation of Malawi (ESCOM). The demand forecast is presented in the Mini Integrated Resource Plan (IRP) of Malawi. Table 23 summarises the national electricity demand forecast and comments on the methodology and the main drivers of the demand. The review of the national electricity demand forecast is presented in Section A1.5.2 and the updated electricity demand forecast which will be used in the 'SAPP Regional Generation and Transmission Expansion Plan' is presented in Section A1.5.3.

Table 27 Malawi's national electricity demand forecast

Item	**Demand forecast information provided by utility – *final version in last sub-section***												
National demand forecast		2015		2020		2025		2030		2035		2040	
		GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW
	Low	2,106	462	2,979	654	-	-	-	-	-	-	-	-
	Base	2,106	462	3,383	743	-	-	-	-	-	-	-	-
	High	2,106	462	3,755	824	-	-	-	-	-	-	-	-
	LF	52%		52%		-		-		-		-	
Forecast period	The national demand forecast is a short to medium term forecast covering the period 2015-2020. Three scenarios are developed: the Low Scenario that follows the past trend in access to electricity; the Base Scenario representing an optimal path that assumes the target of 30% in access to electricity in 2030 and the High scenario that assumes the target of 50% in access to electricity in 2030.												
Methodology used	The national demand forecast is broken down by consumer sectors to: urban households, rural households, agriculture, construction, mining, manufacturing and services. The national demand forecast methodology follows an end user bottom up approach and it uses a trend line analysis to forecast underlying parameters. The effect of demand-side management measures is not included in the electricity demand forecast; suppressed demand is taken into account; transmission and distribution system losses are not shown explicitly in the electricity demand forecast. Imports and exports are not included in the national demand forecast.												
Forecasting parameters	Electrification rate for urban and rural households, number of rural and urban households, average consumption per urban and rural household, consumption per identified key economic sector for the base year, GDP growth rate for the forecast period.												
Main drivers	The main drivers of the electricity demand forecast are the residential demand (approx. 50% of total forecasted demand) and the agriculture sector demand (approx. 22% of total forecasted demand). The outturn of the electricity demand forecast depends heavily on the ability of the government to materialise the plan for increased electricity access to urban and rural households by 2030.												

Source: Summary of information from ESCOM

A1.5.2 Review of utility's demand forecast

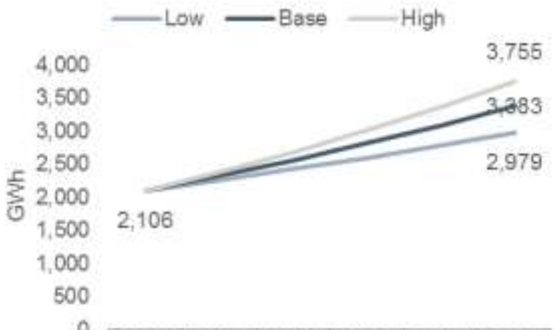
National demand forecast

The national energy demand forecast was developed for the period 2015-2020. The forecast includes three scenarios:

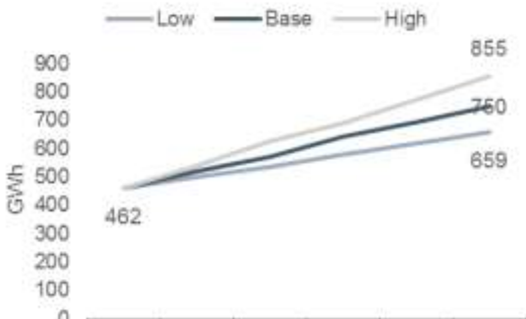
- Low Scenario - that follows the past trend in access to electricity
- Base Scenario -representing an optimal path that assumes the target of 30%in access to electricity in 2030
- High Scenario- that assumes the target of 50%in access to electricity in 2030.

Figure 4 presents the peak and energy demands electricity forecast for the three scenarios. The average annual demand growth rate is 7.2% for the Low scenario, 9.9% for the Base Scenario and 12.3% for the High Scenario. The electricity demand forecast presented in Figure 4 does not show the transmission and distribution system losses. The transmission and distribution system technical losses are estimated 13% of energy.

Figure 4 Malawi electricity demand forecast (MW, GWh)



	2015	2016	2017	2018	2019	2020
Low	2,106	2,261	2,425	2,599	2,784	2,979
Base	2,106	2,323	2,558	2,812	3,087	3,383
High	2,106	2,382	2,684	3,012	3,369	3,755



	2015	2016	2017	2018	2019	2020
Low	462	501	537	578	617	659
Base	462	520	573	640	693	750
High	462	538	627	690	772	855

Source: Malawi's Mini Integrated Resource Plan, 2016

Forecasting methodology

The national demand forecast in Malawi is disaggregated by key economic sectors and it follows a sectoral approach. The forecast is developed by applying a calculated electricity demand growth rate to the 2015 actual demand for each economic sector. Therefore, the base year of the forecast is 2015 and the projections extend up to 2020. The aggregated electricity demand forecast includes the total consumption by ESCOM customers, estimates of load shedding and estimates of consumption from those who generate their own power. The effect of demand-side management measures was not included in the forecast and it was assumed that the technological structure of energy demand, including end-use efficiency, will remain constant over the forecast period. The national demand forecast does not show the transmission and distribution system technical and commercial losses and the spinning reserves margin. The transmission and distribution system losses should be added on top of the electricity demand forecast to get sent out figures that are comparable to other country forecasts.

The forecast is broken down by consumer sectors to: urban households, rural households, agriculture, construction, mining, manufacturing and services. Individual electricity demand forecasts are developed for each sector and then the forecasts are aggregated to form the national electricity demand forecast. The identified consumer categories of the demand forecast reflect the key economic activities in Malawi. The composition of the GDP presented in Table 28reveals that the key economic sectors in Malawi are the agriculture sector, the construction sector, the mining sector, the manufacturing sector and services. The most significant economic sector is the agriculture sector contributing 30% to the country's GDP.

Table 28 Malawi's GDP composition 2011-2015

	2011	2012	2013	2014	2015
Agriculture, hunting, forestry, fishing	30.8%	29.9%	29.9%	27.5%	29.3%
Mining	0.9%	1.0%	1.0%	0.9%	0.9%
Manufacturing	9.9%	9.6%	9.5%	9.4%	9.3%
Electricity, gas and water	1.3%	1.3%	1.3%	1.3%	1.3%
Construction	3.0%	3.0%	2.9%	2.9%	2.9%
Wholesale and retail trade, hotels and restaurants	17.4%	19.4%	17.2%	17.2%	17.1%
Transport, storage and communication	6.3%	6.6%	6.6%	6.8%	6.9%
Finance, real estate and business services	13.4%	13.7%	13.4%	13.1%	12.9%
Public administration, education, health and social work, community, social and personal services	7.1%	7.3%	7.3%	7.1%	7.0%
Other services	9.9%	8.2%	10.9%	13.8%	12.4%

Source: 2014 Annual Economic Report, Ministry of Finance, Economic Planning and Development

The household electricity demand forecast is the product of the average consumption per household, the number of households and the percentage of households connected to the grid. The forecast is developed separately for the urban and the rural households. The access to electricity was estimated by a linear extrapolation between 10.0% in 2015 and 15% in 2030 for the low scenario, between 10.0% in 2015 and 30% in 2030 for the base case scenario and between 10.0% in 2015 and 50% in 2030 for the high case scenario. The low case scenario assumes that trend in electricity access will be similar to the historical years. The base case and the high case scenarios set a policy target of 30% and 50% electricity access in 2030, respectively. The linear extrapolation method was also used to forecast the number of urban and rural households. The average electricity consumption per urban and rural household is based on an econometric equation which uses the 2015 average consumption per household, the relativity between average electricity consumption per urban and rural household and GDP, and the GDP growth rate to forecast the average electricity consumption per urban and rural household in the forecast years.

The energy demand forecast for the agriculture, the construction, the mining, the manufacturing and the services sectors is based on the trend analysis of the average annual growth rate registered by the individual sectors over the past years (since 2009) relative to average annual GDP growth. The calculated elasticities assume that:

- ❑ Average annual electricity use per urban household increases at 60% of the GDP growth rate.
- ❑ Average annual electricity use per rural household increases at 20% of the GDP growth rate.
- ❑ Electricity use in the Agriculture and Mining sectors increases at 120% of the GDP rate of growth.
- ❑ Electricity uses in the Manufacturing and Construction sectors respectively increase at 60% and 80% of the annual GDP growth rate.
- ❑ Electricity use in the Services sector increases at the rate of GDP growth

The peak loads were estimated by converting the energy demand forecast to a peak demand forecast with the use of 0.52 load factor.

Finally, the forecast demand of large one-off projects which are expected to come on stream within the forecasting period are added on top of the peak demand forecast.

Parameters used in the demand forecast

For the household electricity demand forecast six external parameters were used: the 2015-2020 access to electricity for all households; the 2015-2020 numbers of urban and rural households; the average electricity consumption per urban and rural household in 2015; the 2016-2020 GDP growth rate; and the 2015-2020 access to electricity for urban and rural households. For the electricity demand forecast of the remaining key economic sector two external parameters were used: the 2015 consumption and the 2016-2020 GDP growth rates.

The national electricity demand forecast uses as a base year 2015. Therefore, the underlying parameters used in the demand forecast were initially calculated for the base year using 2015 actual data.

The actual consumption in2015 including estimates of load shedding and estimates of consumption from those who generate their own power was 2106 GWh. The total demand of 2015was disaggregated by the six sectors and the disaggregated energy consumption is presented in Table 29 below.

Table 29 Malawi electricity consumption in 2015 (GWh)

Sector	Actual electricity consumption from ESCOM
Household	866
Agriculture	528
Construction	6
Mining	100
Manufacturing	256
Services	350

Sector	Actual electricity consumption from ESCOM
Total	2,106

The 2015 access to electricity in Malawi is estimated to be at 10% and three scenarios were developed for the forecast access to electricity: A Low Scenario that follows the past trend in access to electricity; a Base Scenario representing an optimal path that assumes the target of 30% in 2030 (the lower end of the Goma policy), and a High Scenario that assumes the target of 50% in 2030 (the higher end of the GoM policy). The split between the urban and the rural electricity access was calculated backwards by setting a target for the urban households of 70% by 2030 for the Low Scenario, 90% for the Base Scenario and 90% for the High Scenario. For this calculation the total electricity access and the estimate of urban and rural households was also used.

Table 30 Malawi access to electricity for all households forecast 2015-2030 (%)

	Low Scenario			Base Scenario			High Scenario		
	Total	Urban	Rural	Total	Urban	Rural	Total	Urban	Rural
2015	10.0	50.7	0.7	10.0	60.7	0.7	10.0	60.7	0.7
2020	11.7	63.8	0.9	16.6	70.5	5.5	23.3	70.5	13.8
2025	13.3	-	-	23.3	-	-	36.7	-	-
2030	15.0	70	1.3	30.0	90.0	15.0	50.0	90.0	40.0

Source: Malawi's Mini Integrated Resource Plan, 2016

The number of urban and rural household was estimated from the 2008 Census and is presented in Table 31 below. The intermediate years were calculated through linear interpolation.

Table 31 Malawi number of urban and rural household

Year	Urban Household Number	Urban Household (%)	Rural Household Number	Rural Household (%)	Total Household Number	Total Household (%)
2010	411,047	14.0	2,537,309	86.0	2,948,356	100.0
2015	600,482	15.5	3,081,723	84.5	3,682,253	100.0
2020	789,918	17.0	3,626,237	83.0	4,416,150	100.0
2030	1,168,788	20.0	4,715,167	80.0	5,883,945	100.0

Source: Malawi's Mini Integrated Resource Plan, 2016

The average electricity use of urban and rural household was estimated based on the 2015 consumption and the number of connected urban and rural consumers.

Table 32 Malawi average electricity use of urban and rural household (kWh)

Average electricity use of urban households	Average electricity use of rural households
2329.26	776

Source: Malawi's Mini Integrated Resource Plan, 2016

The assumed GDP growth rates were 5% for the Low Scenario, 6% for the Base Scenario and 7% for the High Scenario.

The system wide load factor of 0.52 has been used to calculate the peak demand. The system wide load factor was based on the work of ICF International. On top of the calculated peak demand forecast large one-off projects are added. The load from expected large one-off projects is presented below.

Table 33 Malawi loads from large one-off projects (MW)

Year	Very likely step loads	Likely step loads	Least likely step loads
2015	0	0	0
2016	5	10	15
2017	5	11	38
2018	7	23	29
2019	6	15	32
2020	5	7	31

Source: Malawi's Mini Integrated Resource Plan, 2016

The transmission and distribution system technical losses are estimated 13% of energy for 2015. A forecast on the development of the transmission's and distribution's system technical losses is not provided. The value of 13% is assumed for all the years of the demand forecast.

Updated historical demand data up to 2015 for the sales by customer category, the losses, the suppressed demand, the sent-out energy, and the maximum demand are not available.

Table 34 Underlying parameters of the electricity demand forecast

	Number of urban households	Number of rural households	Access to electricity of urban households (%)	Access to electricity of rural households (%)	Access to electricity for all households (%)	Average consumption per urban household (GWh)	Average consumption per rural household (GWh)	GDP growth rate (%)
2015	600,482	3,081,774	57.7%	0.7%	10.0%	2,447	816	5.5%
2016	638,369	3,190,666	58.5%	0.7%	10.3%	2,527	825	5.5%
2017	676,256	3,299,559	59.4%	0.8%	10.7%	2,611	834	5.5%
2018	714,143	3,408,452	60.2%	0.8%	11.0%	2,697	843	5.5%

	Number of urban households	Number of rural households	Access to electricity of urban households (%)	Access to electricity of rural households (%)	Access to electricity for all households (%)	Average consumption per urban household (GWh)	Average consumption per rural household (GWh)	GDP growth rate (%)
2019	752,030	3,517,345	61.0%	0.9%	11.3%	2,786	852	5.5%
2020	789,918	3,626,238	61.8%	0.9%	11.7%	2,878	861	5.5%
2021	827,805	3,735,131	62.6%	1.0%	12.0%	2,973	871	5.5%
2022	865,692	3,844,024	63.5%	1.0%	12.3%	3,071	880	5.5%
2023	903,579	3,952,917	64.3%	1.1%	12.7%	3,172	890	5.5%
2024	941,466	4,061,810	65.1%	1.1%	13.0%	3,277	900	5.5%
2025	979,353	4,170,703	65.9%	1.1%	13.3%	3,385	910	5.5%
2026	1,017,240	4,279,595	66.7%	1.2%	13.7%	3,497	920	5.5%
2027	1,055,127	4,388,488	67.5%	1.2%	14.0%	3,612	930	5.5%
2028	1,093,014	4,497,381	68.4%	1.3%	14.3%	3,732	940	5.5%
2029	1,130,901	4,606,274	69.2%	1.3%	14.7%	3,855	951	5.5%
2030	1,168,788	4,715,167	70.0%	1.4%	15.0%	3,982	961	5.5%
2031	1,206,675	4,874,007	70.8%	1.4%	15.3%	4,113	972	5.5%
2032	1,244,562	5,038,198	71.6%	1.5%	15.7%	4,249	982	5.5%
2033	1,282,449	5,207,919	72.5%	1.5%	16.0%	4,389	993	5.5%
2034	1,320,336	5,383,359	73.3%	1.5%	16.3%	4,534	1,004	5.5%
2035	1,358,223	5,564,708	74.1%	1.6%	16.7%	4,684	1,015	5.5%
2036	1,396,110	5,752,166	74.9%	1.6%	17.0%	4,838	1,026	5.5%
2037	1,433,997	5,945,939	75.7%	1.7%	17.3%	4,998	1,037	5.5%
2038	1,471,884	6,146,240	76.5%	1.7%	17.7%	5,163	1,049	5.5%
2039	1,509,771	6,353,289	77.4%	1.8%	18.0%	5,333	1,060	5.5%
2040	1,547,659	6,567,312	78.2%	1.8%	18.3%	5,509	1,072	5.5%

Source: Malawi's Mini Integrated Resource Plan, 2016

Comments on the demand forecast

The forecasting methodology is mainly based on trend analysis but includes trends in electricity consumption relative to trends in external drivers (e.g., GDP) which is a form of econometric analysis. The historical trend line analysis was not available and we have assumed that the estimated elasticities are satisfactory for the energy demand forecast.

The accuracy of the electricity demand forecast model can be checked in one or both of two ways: forecasts versus outturn (forecasts prepared in the past can be compared with the outturn - an *ex post* review -) and/or forecast over a historical period (use the model to forecast a historical period - back-casting). However, historical forecasts or actual historical data were not available.

The GDP growth rate used in the base case of the electricity demand forecast seems to be the most likely scenario as it reflects more accurately the development of the economy. The forecast GDP growth rates used in the electricity demand forecast were benchmarked against the IMF and the World Bank projections. The high case scenario of the GDP growth rate forecast is clearly optimistic.

Figure 5 Malawi's GDP growth rate forecast

Source: IMF, WB, Malawi's Mini Integrated Resource Plan, 2016

The national demand forecast covers a short term period; the forecast starts in 2015 and ends in 2020. Therefore, the forecast has to be extended to cover the planning horizon of the SAPP development plan.

The number of rural households was calculated by a linear interpolation between the 2010 actual number of rural households and the 2030 forecast. However, the 2015-2020 number of rural household was miscalculated. Consequently, this meant that estimates of the access to electricity of urban households and rural households was not correct and this affects the average consumption of urban and rural households for 2015 and the 2015-2020 household electricity demand forecast.

The load factor that was used to calculate the peak demand forecast was 52%. The load factor was assumed to remain constant through the forecast period. However, it was observed that the consumption mix changes significantly from year to year. Residential consumption increases from 41% in 2015 to 47% in 2020. Therefore, it would have been expected for the load factor to change from year to year in the demand forecast.

Table 35 Malawi's consumption mix over the forecast period

	Households	Agriculture	Construction	Mining	Manufacturing	Services
2015	41%	25%	0%	5%	12%	17%
2016	42%	25%	0%	5%	12%	16%
2017	44%	24%	0%	5%	11%	16%
2018	45%	24%	0%	5%	11%	16%
2019	46%	24%	0%	5%	10%	15%
2020	47%	24%	0%	5%	10%	15%

Source: Malawi's Mini Integrated Resource Plan, 2016

The electricity demand forecast grows at a higher rate in comparison to the growth rate of the economy. Table compares the demand forecast growth rates with the GDP growth rate. This result can be explained from the increasing rate of electricity access for household in the demand forecast.

Table 36 Malawi's demand forecast growth rate vs GDP forecast growth rate

	Energy demand growth rate			GDP growth rate		
	Low	Base	High	Low	Base	High
2016	7%	10%	13%	5%	6%	7%
2017	7%	10%	13%	5%	6%	7%
2018	7%	10%	12%	5%	6%	7%
2019	7%	10%	12%	5%	6%	7%
2020	7%	10%	11%	5%	6%	7%

Source: Malawi's Mini Integrated Resource Plan, 2016Updates to the forecast

A1.5.3 Updates to base forecast and assumptions for low forecast

For the base forecast in the Pool Plan, an assumption at the lower end of GDP growth would seem appropriate. We have assumed a GDP growth rate of 5.5%, instead of 5%. Additionally, the miscalculation presented in Section A1.5.2 relating to the household numbers was corrected in the updated electricity demand forecast. The load factor is assumed to drop over the years as the consumption mix changes. Finally, the technical and the commercial losses were added to the demand forecast.

The 'low' demand forecast is based on an assumption of lower economic growth and a slow-down in the pace of electrification in the country. The annual average rate of growth in maximum demand in the base demand forecast is 11.1% per annum. In the low forecast, this is reduced to 3.4% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 37. The corresponding figures for the low forecast are given in Table 38. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 37 Malawi's updated electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)
2015	1,554	0	13%	1,756	329	61%
2016	1,912	0	13%	2,161	377	65%
2017	2,213	0	13%	2,501	449	64%
2018	2,605	0	13%	2,944	529	64%
2019	3,061	0	13%	3,459	621	64%
2020	3,535	0	13%	3,994	719	63%
2021	3,917	0	13%	4,426	795	64%
2022	4,334	0	13%	4,897	878	64%
2023	4,789	0	13%	5,412	967	64%
2024	5,286	0	13%	5,973	1,064	64%
2025	5,828	0	13%	6,586	1,169	64%
2026	6,419	0	13%	7,253	1,282	65%
2027	7,063	0	13%	7,981	1,405	65%
2028	7,765	0	13%	8,774	1,538	65%
2029	8,528	0	13%	9,637	1,682	65%
2030	9,404	0	13%	10,627	1,873	65%
2031	10,332	0	13%	11,675	2,063	65%
2032	11,337	0	13%	12,811	2,267	65%
2033	12,428	0	13%	14,044	2,489	64%
2034	13,611	0	13%	15,380	2,728	64%
2035	14,893	0	13%	16,829	2,986	64%
2036	16,283	0	13%	18,400	3,265	64%
2037	17,789	0	13%	20,102	3,566	64%
2038	19,422	0	13%	21,947	3,892	64%
2039	21,190	0	13%	23,945	4,243	64%
2040	23,102	0	13%	26,105	4,620	65%
AAG	**11.4%**	-	-	**11.4%**	**11.1%**	-

Source: Malawi's Mini Integrated Resource Plan, 2016

Table 38 Malawi's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*1,756*	*329*	*1,756*	*329*
2016	*2,161*	*377*	*1,867*	*326*
2017	2,501	449	1,899	341
2018	2,944	529	2,000	359
2019	3,459	621	2,101	377
2020	3,994	719	2,189	394
2021	4,426	795	2,269	408
2022	4,897	878	2,350	421
2023	5,412	967	2,437	436
2024	5,973	1,064	2,525	450
2025	6,586	1,169	2,616	464
2026	7,253	1,282	2,712	479
2027	7,981	1,405	2,808	494
2028	8,774	1,538	2,909	510
2029	9,637	1,682	3,011	526
2030	10,627	1,873	3,076	542
2031	11,675	2,063	3,184	563
2032	12,811	2,267	3,297	583
2033	14,044	2,489	3,411	605
2034	15,380	2,728	3,529	626
2035	16,829	2,986	3,651	648
2036	18,400	3,265	3,776	670
2037	20,102	3,566	3,904	692
2038	21,947	3,892	4,034	715
2039	23,945	4,243	4,170	739
2040	26,105	4,620	4,309	763
AAG	11.4%	11.1%	3.7%	3.4%

Source: Malawi's Mini Integrated Resource Plan, 2016

A1.6 Mozambique

A1.6.1 Load forecast information supplied by the utility

Mozambique's national electricity demand forecast was developed in 2012by Norconsult and Vattenfall for EDM E.P. The demand forecast is presented in Volume II of Mozambique's Master Plan Update Project, 2012-2027. Table 39 summarises the national electricity demand forecast, the methodology used and main drivers of the demand. The review of the national demand forecast, methodology and the forecasting parameters will be presented in Section A1.6.2.

Table 39 Mozambique's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*												
Country's demand forecast		2015		2020		2025		2030		2035		2040	
		MW	Gwh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
	Low	1,190	7,268	1,616	9,797	1,863	11,397	-	-	-	-	-	-
	Likely	1,384	8,738	1,978	12,366	2,343	14,653	-	-	-	-	-	-
	High	1,518	9,758	2,234	14,172	2,778	17,456	-	-	-	-	-	-
Forecast period	The load forecast is made for the period 2015-2026												
Methodology used	The forecast offers peak demand and total energy forecasts broken down by regions, provinces and customer service area. A breakdown by consumer sector is not provided in the forecast. The forecast is built on macro-economic drivers, GDP growth rate, income elasticity and price elasticity. In addition, individual large loads are included. The forecast separates the national load by regions and customer service area. The national forecast is then constructed by assigning 'coincidence' factors for each region's impact on the national forecast. The forecast includes demand side measures but load forecasts are limited to substations and thus do not show distribution losses explicitly. Transmission losses are shown in the forecast.												
Forecasting parameters	The forecast uses macro-economic parameters such as GDP growth and elasticity, price elasticity, demographic growth and additions of large projects.												
Main drivers	GDP growth throughout the forecasting period is one of the main drivers of load growth. The GDP forecast is not broken down by regions but covers the entire country. Large projects are included in the GDP forecast but are modelled individually in the load forecast leading to potential double counting. In order to adjust for this an adjustment of -1.5% was made to the GDP growth forecast. Due to a lack of information the forecast is not able to distinguish between customer groups but is broken down by regions, and substations.												

Source: Summary of information from EDM

A1.6.2 Review of utility's demand forecast

National demand forecast

The national electricity demand forecast in Mozambique was developed by Norconsult for Electricidade de Moçambique (EdM) in 2012. The forecast period starts in 2010 and extends to 2026. Table 40presents the national demand forecast for peak demand and total energy demand for the forecasting period. Three scenarios for the demand forecast were developed representing a low growth scenario, a medium growth scenario and a high growth scenario. The forecast shows system losses. It does not show volumes for planned exports. Demand side management and loss reduction strategies are included in the forecast.

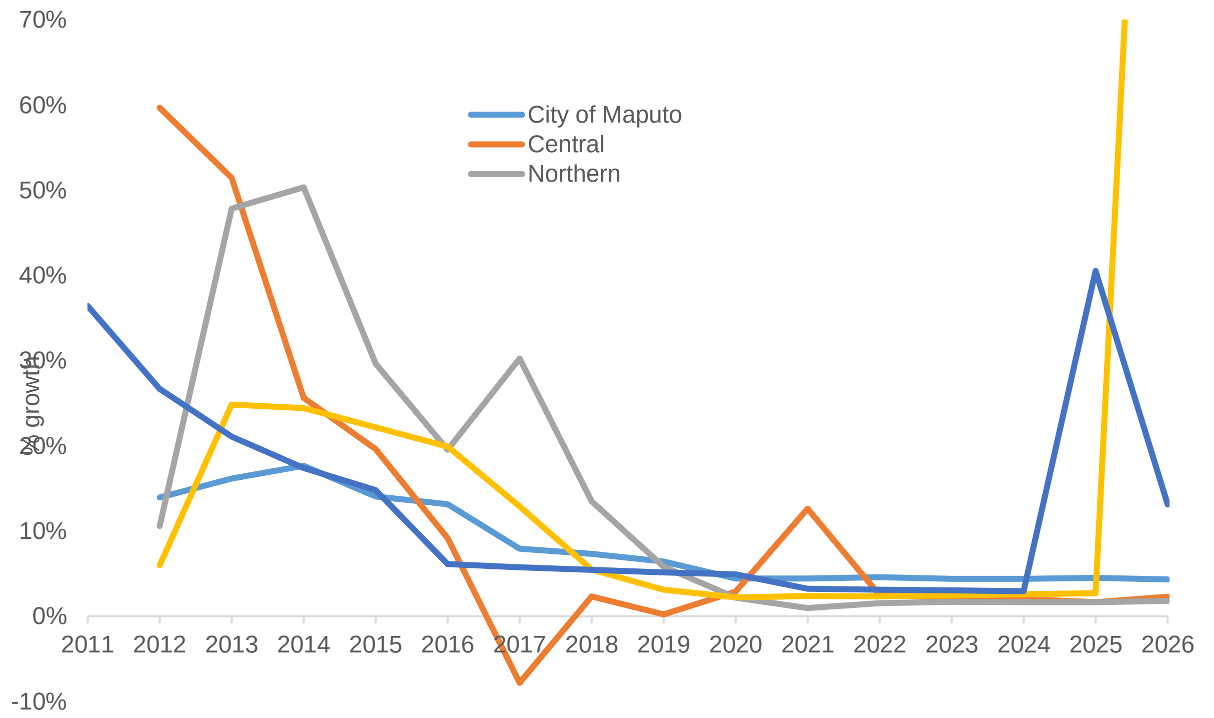
Table 40 Mozambique's national electricity demand forecast

	Low case			Medium case			High case		
	MW	GWh	LF	MW	GWh	LF	MW	GWh	LF
2011	563.0	3,255.0	66%	563.0	3,255.0	66%	563.0	3,255.0	66.0%
2012	719.8	4,258.2	68%	768.2	4,625.8	69%	801.8	4,880.8	69.5%
2013	876.6	5,261.4	69%	973.4	5,996.6	70%	1,040.6	6,506.6	71.4%
2014	1,033.4	6,264.6	69%	1,178.6	7,367.4	71%	1,279.4	8,132.4	72.6%
2015	1,190.2	7,267.8	70%	1,383.8	8,738.2	72%	1,518.2	9,758.2	73.4%
2016	1,347.0	8,271.0	70%	1,589.0	10,109.0	73%	1,757.0	11,384.0	74.0%
2017	1,414.2	8,652.6	70%	1,686.2	10,673.2	72%	1,876.2	12,081.0	73.5%
2018	1,481.4	9,034.2	70%	1,783.4	11,237.4	72%	1,995.4	12,778.0	73.1%
2019	1,548.6	9,415.8	69%	1,880.6	11,801.6	72%	2,114.6	13,475.0	72.7%
2020	1,615.8	9,797.4	69%	1,977.8	12,365.8	71%	2,233.8	14,172.0	72.4%
2021	1,683.0	10,179.0	69%	2,075.0	12,930.0	71%	2,353.0	14,869.0	72.1%
2022	1,728.0	10,483.5	69%	2,142.0	13,360.8	71%	2,459.3	15,515.8	72.0%
2023	1,773.0	10,788.0	69%	2,209.0	13,791.5	71%	2,565.5	16,162.5	71.9%
2024	1,818.0	11,092.5	70%	2,276.0	14,222.3	71%	2,671.8	16,809.3	71.8%
2025	1,863.0	11,397.0	70%	2,343.0	14,653.0	71%	2,778.0	17,456.0	71.7%
2026	2,813.0	19,497.0	79%	3,293.0	22,753.0	79%	3,728.0	25,556.0	78.3%

Source: EdM, 2016

Figure 6 shows the annual growth of peak demand under the 'medium' scenario. The average annual peak demand growth rate of the medium scenario is 13%, whereas in the low and high cases it is 12% and 14%, respectively. The growth slows down near the end of the forecasting period due to a slowdown in the development of new large projects.

Figure 6 Peak demand growth by regions [medium scenario] [3]



Source: ECA

Forecasting methodology

The electricity supply in the country is divided into three systems, the Northern, Central and Southern system with the Northern and Central systems being interconnected through the 220kV line between Mat ambo and Chibata. The operation of the national grid is divided into four regions, namely Northern (ATNO, Nampula), Central-Northern (ATCN, Quelimane), Central (ATCE, Chimoio) and Southern (ATSU, Maputo). Consequently, the demand forecast was developed separately for each system and then the individual demand forecasts of each system were aggregated to form the national electricity demand forecast. The coincident load factor of each system was also taken into account for the development of the national peak demand forecast.

The demand forecast of each system covers the period 2011-2026 and consists of two main components:

- The *natural growth* which represents the demand from general customers.
- Large individual loads which represents the demand from new projects.

The two components are aggregated to form the national demand forecast under three scenarios: Low, Medium (base case) and High. Areas of high potential economic development were identified at substation level and substations assigned a potential 'hot-spot' growth profile.

[3] Load from the Mozal aluminium smelter is included as potential load in medium and high scenarios. The current contract Mozal has with Eskom is set to expire 31/12/2025 and will become a load on the national grid, causing the spike in Southern peak load growth.

The natural growth of the system is modelled on a substation level with a bottom-up approach. The forecast uses GDP growth rates, income elasticity and price elasticity to generate growth profiles for individual substations. The forecast builds on 2011 peak demand data and total energy demand data, when available. When total energy demand is not available, a representative load factor was assumed. Regional and distribution area peak demand forecasts are found by aggregating substation data and using a regional coincidence factor.

Large individual loads were identified and future peak demand identified. Total energy demand was then derived from peak demand using an industry specific load factor. The projects were assigned to three forecasting scenarios (low, medium and high) based on uncertainty of implementation.

The forecast uses a 'natural growth' approach plus scheduled large projects to create the national demand forecast. The 'natural growth' forecast is created at a substation level uses GDP forecast, income elasticity and price elasticity, to create growth profiles which are applied to the substations. Peak demand forecasts at a distribution area level, regional level and national level are derived from the substation data and by applying a coincidence factor. The load from large projects is aggregated with the 'natural growth' to create a total national demand forecast.

- When forecasting 'natural growth', growth profiles were created and applied to individual substation. The growth profiles were based on GDP forecast, income elasticity and price elasticity, and represent the three scenarios used for the national demand forecast. Furthermore, areas of high potential economic development were identified and assigned a 'hotspot' growth profile.
- For forecasting large loads, the projects were identified and assigned to the closest substation. Since the loads were defined at each substation, distribution losses are excluded in the forecast. In order to represent uncertainty of implementation the projects were assigned to the forecasting scenarios, low, medium and high. The forecast for the large loads was made for peak demand and total energy demand calculated from varying load factors.

The forecast is based on substation data from 2011 and growth profiles and large loads built on top to create the forecast. For most substations peak demand data was available but in cases where total energy was not available, a load factor was assumed. No information exists in the forecast on sales by customer categories but substations that have potential of high economic growth were assigned a 'hotspot' growth profile which has a higher growth rate.

The load forecast includes forecasted increase by new connections added during the forecasting period. New connections are listed in the masterplan and the load forecast has added new connections to its closest substation.

The spatial model is at a substation level where demand forecasts are created for all substations and GDP growth rates, income elasticity and price elasticity are used for the forecast. The year 2011 is used as a base year and the forecast builds upon that year. GDP forecasts are only done for entire Mozambique and do take account of the effect that large projects have on GDP. Since the national GDP forecast reflects the impact of large projects on GDP growth, a new and lower GDP growth rate was applied and the difference would be attributed to large projects. The model assumes a difference of growth rates at substations and has identified ´hot spots´ where economic activities will be higher during the forecasting period. The GDP growth rates used for the forecast are presented in Figure 7.

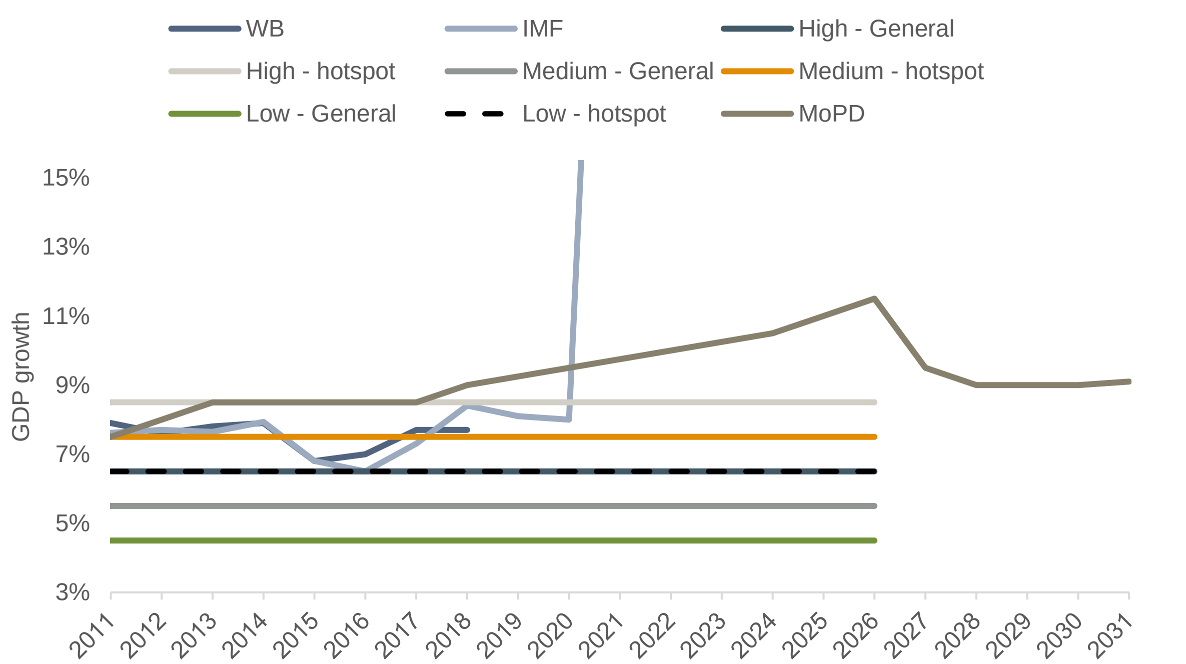
The forecast does not take demographic data into account but rather follows Mozambique's master plan for new connection rates. The master plan aims at expanding and upgrading the current transmission network to ensure supply to large projects and secondary growth in major centres. This is reflected in the forecasted national load factors (Table 41) and shows that large projects with higher load factor will become dominant in the medium-term while natural growth will decrease the system load factor toward the end of the forecasted period.

Parameters used in the demand forecast

The main drivers of the natural growth are GDP growth rates, income elasticity and price elasticity.

GDP growth rate is forecasted by the Ministry of Planning and Development at a national level. The forecast includes the effect large projects will have on GDP growth. To exclude large projects from GDP growth, a fixed growth rate was assumed and adjusted to scenarios and 'hotspots'. As can be seen in Figure 7 the GDP growth rates vary from 4% (general areas – low scenario) to 8% (hotspots - high scenario). GDP forecasts from International institutions forecast an annual GDP growth of 7-8% during the period 2015-2020, which includes effects of large projects. The GDP forecast used for the demand forecast was overestimated during the period 2011-2014, when compared to historical IMF and WB data.

Figure 7 Comparison of GDP growth forecasts[4]



Source: EdM, 2016. IMF, 2016. WB, 2016

[4] The IMF forecasts 38.9% growth of GDP in the year 2021 due to start of natural gas production.

Income elasticity is derived from historical data from two periods, 2005-2011 and 1997-2011. The former period showed an average correlation of 1.48 while the latter showed a correlation of 1.08. The forecast uses a correlation of 1.2 which decreases to 1.1 at varying times, depending on scenario. The price elasticity used for the model is -0.3 for the base/medium scenario, and -0.35 and -0.25 for the low and high scenarios, respectively. A detailed table with the information, along with a forecasted tariff increase schedule is presented in Table 41. The tariff increases are based on experience from South Africa´s Eskom and the built-up need for tariff increase at EDM due to tariffs not being cost reflective.

Table 41 Parameters used for forecast

	GDP elasticity			Real tariff increse (%)		
	Low	Medium	High	Low	Medium	High
2011	1.2	1.2	1.2	-2%	-2%	-2%
2012	1.2	1.2	1.2	-2%	-2%	-2%
2013	1.2	1.2	1.2	10%	8%	5%
2014	1.2	1.2	1.2	12%	5%	3%
2015	1.2	1.2	1.2	10%	5%	3%
2016	1.2	1.2	1.2	8%	5%	3%
2017	1.1	1.2	1.2	2%	2%	2%
2018	1.1	1.2	1.2	0%	0%	0%
2019	1.1	1.2	1.2	0%	0%	0%
2020	1.1	1.1	1.2	0%	0%	0%
2021	1.1	1.1	1.2	0%	0%	0%
2022	1.1	1.1	1.2	0%	0%	0%
2023	1.1	1.1	1.1	0%	0%	0%
2024	1.1	1.1	1.1	0%	0%	0%
2025	1.1	1.1	1.1	0%	0%	0%
2026	1.1	1.1	1.1	0%	0%	0%

Source: EdM, 2016

Comments on the demand forecast

The forecast suffers from the lack of information regarding customer categories. Data on substation peak demand was mostly available and the forecast based on a bottom-up approach from individual substations. The only distinction between substations is the different growth profiles of areas with high potential economic growth (hotspots) and where general growth is estimated. This has the effect that many areas will be overestimated while others underestimated. The ‘hotspots’ were partly identified by analysing future large projects in the area. Should a large project not be implemented it has a knock-on effect in real life demand which is not represented in the forecast.

By comparing the forecast with actual data it is clear that the forecasts overestimated demand growth as even the 'low' scenario forecasts a significantly higher growth than witnessed in real life.

GDP growth rates used in the forecast are somewhat higher than actual data from the IMF and WB. The difference is one percentage point during 2012-2014 but increases to two percentage points for short-term forecasts from the IMF and WB. Since the natural growth forecast builds largely on GDP growth rates, a variation in actual GDP growth rates and forecasted values can cause a high level of discrepancy. This suggests that part of the reason for the forecast overestimating demand growth is the GDP forecast used for modelling.

We have no information regarding the validity of the forecasted large projects, whether they have been implemented, delayed or cancelled. For the sake of Table 43 we assume the information is correct.

Table 42 shows the comparison of the national demand forecast with actual data from EDM. It is clear that the forecast drastically overestimates the peak demand growth during the forecasting period as the most recent data, from 2015, shows that forecasted values for the medium scenario were about 60% higher than actual values.

Historical exports account for the period 2007-2011 show that exports reach up to 25% of total EdM energy sales. Exports are expected to continue but stabilise at a lower percentage of total sales.

The energy demand forecast provided energy sales. An export ratio was estimated from the data, see above paragraph, technical losses were estimated from historical data provided in the report containing the demand forecast. Energy sent out was then calculated as follows:

Energy sales = (Energy sales * (1 + export ratio)) * (1 + technical losses)

Table 42 National demand forecast - Medium

		2011	2012	2013	2014	2015	2016	2021	2026
Northern	MW	85	133	181	228	276	324	523	568
	GWh	494	808	1,122	1,437	1,751	2,065	3,396	3,638
Central	MW	129	206	282	359	435	512	561	624
	GWh	676	1,145	1,614	2,082	2,551	3,020	2,987	3,313
Southern	MW	368	456	544	631	719	807	1,021	2,213
	GWh	2,085	2,655	3,225	3,794	4,364	4,934	6,546	15,802
National total - consolidated	MW	563	769	973	1,179	1,384	1,589	2,075	3,293
	GWh	3,255	4,608	5,961	7,313	8,666	10,019	12,930	22,753
Actual data	**MW**	**616**	**706**	**761**	**830**	**874**			

Source: EdM, 2016

Comments on updated national demand forecast received

After communicating with EdM staff we have received an updated version of the Mozambique national demand forecast. Unfortunately, it only included very brief information on the methodology of the forecast and no information regarding underlying parameters. We also received an estimation of system losses (technical and non-technical) for the forecasting period. The updated demand forecast will be used for the PLEXOS modelling.

The updated forecast we received included demand by customer category for the period 2013-2030. Only technical losses were provided but after communicating with EdM staff we were given the estimation of total system losses (technical and non-technical). We were not provided with a *Domestic peak demand* (excluding MOZAL) in the updated demand forecast but have assumed a load factor that increases from 70% at the start of the forecasting period to 72% in 2040. We were then able to calculate the *Domestic peak demand sent out.* This assumption has been confirmed by EdM staff.

A1.6.3 Updates to base forecast and assumptions for low forecast

Since the above was written, fresh figures were supplied by EDM and the decision was made to include MOZAL in the national demand of Mozambique figures. This is different to the way Mozambique's load forecast has typically been presented before in SAPP documents. Correspondingly, exports from Cahora Bassa are not included in Mozambique's demand, but form part of South Africa's demand and Zimbabwe's demand.

The assumptions made on MOZAL are maximum demand of 950 MW and a 92% load factor. The forecast provided only covered the period 2015-2030 and in order to extend it to 2040 we have extrapolated the *Non-Mozal Energy sales* data and added MOZZAL demand. This is assumed to continue to 2040, though the source of supply may change when the present supply contract expires in 2027.

The 'low' demand forecast is based on an assumption of lower economic growth and a slow-down in the pace of electrification in the country. The annual average rate of growth in maximum demand in the base demand forecast is 3.1% per annum. In the low forecast, this is reduced to 2.7% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 43. The corresponding figures for the low forecast are given in Table 44. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 43 Mozambique's updated electricity demand forecast

	Non-Mozal Energy sales (GWh)	Exports (GWh)	Losses (%)	Domestic energy sent out (GWh)	Domestic peak demand sent out (MW)	Load factor (%)
2015	4,024	-	25%	12,686	1,770	82%
2016	4,521	-	25%	13,307	1,872	81%
2017	4,879	-	25%	13,755	1,945	81%
2018	5,337	-	25%	14,327	2,038	80%
2019	5,913	-	25%	15,047	2,155	80%
2020	6,495	-	25%	15,775	2,255	80%
2021	7,080	-	23%	16,365	2,350	79%
2022	7,758	-	23%	17,199	2,484	79%
2023	8,384	-	23%	17,969	2,608	79%
2024	8,742	-	23%	18,409	2,679	78%
2025	9,114	-	23%	18,866	2,752	78%
2026	8,951	-	20%	18,397	2,653	79%
2027	9,395	-	20%	18,930	2,737	79%
2028	9,852	-	20%	19,479	2,824	79%
2029	10,322	-	20%	20,043	2,914	79%
2030	10,806	-	20%	20,623	3,006	78%
2031	11,180	-	20%	21,073	3,077	78%
2032	11,568	-	20%	21,537	3,151	78%
2033	11,968	-	20%	22,018	3,227	78%
2034	12,383	-	20%	22,516	3,306	78%
2035	12,812	-	20%	23,031	3,388	78%
2036	13,256	-	20%	23,563	3,472	77%
2037	13,715	-	20%	24,115	3,559	77%
2038	14,190	-	20%	24,685	3,650	77%
2039	14,682	-	20%	25,275	3,743	77%
2040	15,191	-	20%	25,885	3,840	77%
AAG	**5.5%**	**-**	**-**	**2.9%**	**3.1%**	**-**

Source: EdM, 2016 and incorporation of MOZAL

Table 44 Mozambique's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*12,686*	*1,770*	*12,172*	*1,770*
2016	*13,307*	*1,872*	*12,782*	*1,859*
2017	13,755	1,945	13,213	1,921
2018	14,327	2,038	13,853	2,002
2019	15,047	2,155	14,547	2,102
2020	15,775	2,255	15,134	2,187
2021	16,365	2,350	15,687	2,267
2022	17,199	2,484	16,466	2,379
2023	17,969	2,608	17,180	2,483
2024	18,409	2,679	17,586	2,541
2025	18,866	2,752	18,006	2,602
2026	18,397	2,653	17,440	2,520
2027	18,930	2,737	17,923	2,590
2028	19,479	2,824	18,419	2,662
2029	20,043	2,914	18,926	2,735
2030	20,623	3,006	19,446	2,810
2031	21,073	3,077	19,847	2,868
2032	21,537	3,151	20,261	2,928
2033	22,018	3,227	20,687	2,989
2034	22,516	3,306	21,127	3,053
2035	23,031	3,388	21,581	3,118
2036	23,563	3,472	22,049	3,186
2037	24,115	3,559	22,532	3,256
2038	24,685	3,650	23,030	3,328
2039	25,275	3,743	23,543	3,402
2040	25,885	3,840	24,073	3,479
AAG	2.9%	3.1%	2.8%	2.7%

Source: EdM, 2016 and incorporation of MOZAL

A1.7 Namibia

A1.7.1 Load forecast information supplied by the utility

The Namibian electricity demand forecast is presented in two documents. An Excel model in the document '20160113 ET Load Forecast Final Excel Skorpion.xlsb' which provides energy and peak demand forecasts for the period 2012-2035. However, it excludes the Skorpion zinc mine. The Excel model provides data on load factors and exports whose inputs were used to create the table used for the SAPP Pool Plan. The other forecast that was provided was presented in the document 'NIRP Update Preliminary Draft of Partial Final Report for Discussion Feb19' and developed by the firm Hatch for the Electricity Board of Namibia. The forecast developed by Hatch will be the main forecast relied on for the SAPP Pool Plan.

The energy demand and peak load forecasts will be presented in the first part of Section A1.7.2, followed by a review of the methodology and parameters used. Section A1.7.3 provides the Namibia electricity demand forecast, incorporating data from both forecasts. This will be used in the SAPP Pool Plan.

Table 45 Namibia's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*						
Country's demand forecast	**Generation peak (MW)**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
	Low scenario	597.0	752	868.6	1,019	1,188	-
	Reference scenario	597.0	786	931	1,119	1,329	-
	High scenario	597.0	842	1,019	1,245	1,502	-
	Generation energy (GWh)	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
	Low scenario	3,853	4,916	5,651	6,594	7,661	-
	Reference scenario	3,871	5,100	5,991	7,147	8,490	-
	High scenario	4,272	5,448	6,526	7,911	9,565	-
	Energy sales (GWh)	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
	Low scenario	3,387	4,320	4,966	5,795	6,733	-
	Reference scenario	3,402	4,483	5,265	6,281	7,461	-
	High scenario	3,413	4,789	5,735	6,953	8,407	-
Forecast period	The forecast covers the period from 2015-2035, building on top of 2014 actual data.						
Methodology used	The forecast combines regression analysis for organic growth forecast and adds step-loads under three scenarios, low, reference scenario and high.						
Forecasting parameters	GDP growth for organic growth and interviews with industry and utility for step-loads.						

Item	Demand forecast information provided by utility – *final version in last sub-section*
Main drivers	Step-loads and organic growth are the main drivers for the forecast. Step-loads added during the forecasting period account for 15% of energy sales in the last year of forecasting period.

Source: Summary of information from Nampower

A1.7.2 Review of utility's demand forecast

National demand forecast

The Namibia national electricity demand forecast represent the period 2015-2035 and includes forecasted demand from commercial, residential and industrial sectors. The forecast builds on 2014 actual data and 2015 estimates as base values.

The forecast provides energy demand and peak demand under three scenarios; high, reference and low, and with energy demand disaggregated by organic growth, step loads and effects of DSM. The High, Reference and Low scenarios are provided in Table 46, Table 47and Table 42, respectively.

A further breakdown and review of parameters used for the forecast is provided in a later section.

Table 46 National demand forecast – High scenario

	Energy sales (GWh)	Generation Peak (MW)	Generation energy (GWh)				
			Total	Organic	Step	DSM	Losses
2014	**3,184**	**554**	**3,654**	**3,184**	**0**	**0**	**470**
2015	**3,413**	**597**	**3,883**	**3,413**	**0**	**0**	**470**
2016	3,755	651.1	4,272	3,576	202	-24	517
2020	4,789	842.1	5,448	4,217	705	-133	660
2025	5,735	1,018.7	6,526	5,184	821	-270	790
2030	6,953	1,244.9	7,911	6,413	857	-318	958
2035	8,407	1,501.7	9,565	7,974	794	-361	1,158
AAG	4.61%	4.72%	4.61%	4.33%			4.61%

Source: Nampower, 2016

Table 47 National demand forecast – Reference scenario

	Energy sales (GWh)	Generation Peak (MW)	Generation energy (GWh)				
			Total	Organic	Step	DSM	Losses
2014	**3,184**	**554**	**3,654**	**3,184**	**0**	**0**	**470**
2015	**3,402**	**597**	**3,871**	**3,402**	**0**	**0**	**469**
2016	3,728	645.7	4,241	3,552	200	-24	514

	Energy sales (GWh)	Generation Peak (MW)	Generation energy (GWh)				
			Total	Organic	Step	DSM	Losses
2020	4,483	785.9	5,100	4,119	496	-133	618
2025	5,265	930.7	5,991	4,956	579	-270	725
2030	6,281	1,118.50	7,147	5,994	605	-318	865
2035	7,461	1,328.50	8,490	7,280	542	-361	1,028
AAG	4.0%	4.08%	4.0%	3.88%			4.0%

Source: Nampower, 2016

Table 48 National demand forecast – Low scenario

	Energy sales (GWh)	Generation Peak (MW)	Generation energy (GWh)				
			Total	Organic	Step	DSM	Losses
2014	**3,184**	**554**	**3,654**	**3,184**	**0**	**0**	**470**
2015	**3,387**	**597**	**3,853**	**3,387**	**0**	**0**	**467**
2016	3,692	638.2	4,200	3,521	194	-24	509
2020	4,320	752.3	4,916	4,018	436	-133	595
2025	4,966	868.6	5,651	4,730	506	-270	684
2030	5,795	1,019.40	6,594	5,593	519	-318	798
2035	6,733	1,188.10	7,661	6,638	456	-361	928
AAG	3.5%	3.5%	3.5%	3.42%			3.46%

Source: Nampower, 2016

The organic growth is driven by GDP growth in Namibia and is defined as the current system load. The step-loads are individual projects that are considered too big to be a part of the organic growth. The step-loads are from three sectors:

- Mining
- Commercial/Industrial
- Water pumping

Three scenarios were created for the forecasting of step-loads, reference, low and high scenarios. The Namibian mining sector consists mostly of Uranium, Copper and Gold. The probability of each scenario coming true is therefore heavily dependent on the prices of these three metals.

The annual growth rates of the forecasts are 4.0%, 3.5% and 4.6% for the reference scenario, low scenario and high scenario, respectively.

Forecasting methodology

The organic growth during the forecast period was made through regression analysis of various econometric variables. Data from the period 1990-2014 was available for the regression analysis. The only statistically viable correlation was between GDP and energy sales. No viable correlation was found by comparing demographic or price data with energy sales. The forecast uses an econometric equation based on the 24 years of historical data.

Sales (GWh) = 551.77 + 0.386 * GDP_(N$ millions)

The organic growth is built upon actual data from 2014 and estimates from 2015 to create the forecast. The organic growth is only forecasted under one scenario but step-loads under three scenarios aggregated to create the forecast.

The step-loads are from three sectors, Mining, Commercial/Industry and Water Pumps. Each project is given a probability of implementation and assigned to scenarios accordingly. Information regarding start dates, end dates, load factors and size of load was collected through interviews with regulators and utility.

Under the mining category, various projects are already well advanced in terms of construction and are included in all of the scenarios.

Water pumping includes desalination plants and water pumps related to mine developments.

Under the Commercial/Industrial category are shopping centres, port expansions and other similar projects. The category includes housing projects, or electrification programmes, but due to limited information regarding connection rates they were represented as different loads under each scenario. The residential customers are assumed to have a load factor of 0.2 while the rest of commercial/industrial step-loads to have a load factor of 0.6.

Table 49 Number and size of step loads

Sector	Number of projects in scenarios			Load factor	Max Load
	High	Reference	Low		
Mining	15	7	5	0.75	161 MW
Water pumping	3	3	3	0.60	9 MW
Commercial/Industrial	12	12	9	0.2/0.6	213 MW

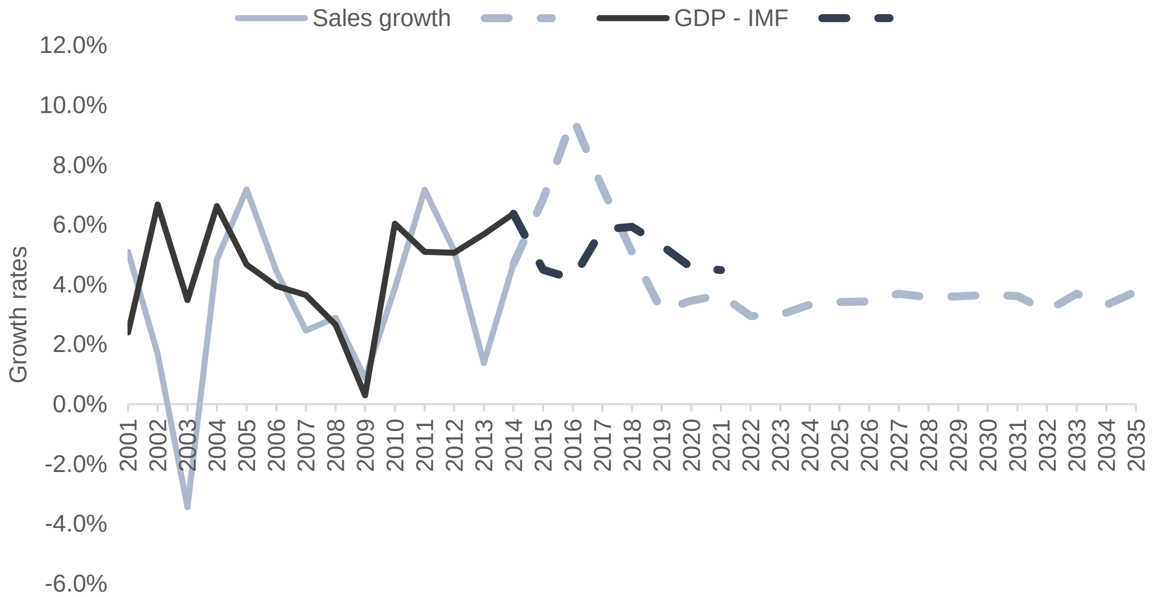
Source: Nampower, 2016

The national demand forecast is aggregated by the organic growth, step-loads and demand side management measures. These DSM include introducing LED lights and installations of residential solar PVs. Furthermore, the forecast provides energy sales, energy generated and transmission losses.

Parameters used in the demand forecast

GDP growth is the only driver of the organic growth portion of the forecast. The correlation between energy sales and GDP was found by doing a regression analysis on over 20 years of historical data. The previous section provides the formula derived from the regression analysis. The formula was used to forecast organic growth during the forecasting period, based on the year 2014 and a GDP growth forecast. The GDP forecast is not provided but Figure 8 compares historical and forecast data of energy sales' growth and GDP growth from NamPower and the IMF, respectively.

Figure 8 Comparison of GDP growth and energy sales growth



Source: Economic Consulting Associates (ECA)

Comments on the demand forecast

The forecast does not include exports from NamPower but annual reports from 2014/2015 show a total of 88 GWh of exports. Future demand for Namibian exports are included in the national forecasts of the importing countries.

The system losses provided in the report show that transmission losses were on average 12% and distribution losses 8.7%. We have used these losses to find the *End user energy sales*. However, we are still missing a data on whether there are any non-technical losses in the Namibian electricity system or if they are included under distribution losses. Until we receive further information we will assume that the losses provided (12% + 8.7%) are all losses in the system.

A1.7.3 Updates to the forecast

Below is Namibia's updated electricity demand forecast for the period 2015-2040. The forecast provided only reached the year 2035 and had to be extended to the year 2040. We have extrapolated the forecast to the year 2040 using the average growth rate for *peak demand sent out* and *Energy sales* for the period 2030-2035, 3.5%. The reference scenario was used as the most likely one.

The 'low' demand forecast is based on an assumption of lower economic growth arising from continuation of mineral prices and a slow-down in the pace of electrification in the country. The annual average rate of growth in maximum demand in the base demand forecast is 4.0% per annum. In the low forecast, this is reduced to 2.5% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 50. The corresponding figures for the low forecast are given in Table 51. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 50 Namibia's updated electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)
2015	3,453	0	11%	3,871	597	74%
2016	3,783	0	11%	4,241	646	75%
2017	4,058	0	11%	4,549	693	75%
2018	4,264	0	11%	4,780	733	74%
2019	4,398	0	11%	4,930	758	74%
2020	4,549	0	11%	5,100	786	74%
2021	4,717	0	11%	5,288	816	74%
2022	4,855	0	11%	5,443	842	74%
2023	5,001	0	11%	5,606	869	74%
2024	5,167	0	11%	5,793	899	74%
2025	5,344	0	11%	5,991	931	73%
2026	5,528	0	11%	6,197	964	73%
2027	5,731	0	11%	6,425	1,001	73%
2028	5,936	0	11%	6,655	1,039	73%
2029	6,150	0	11%	6,895	1,078	73%
2030	6,375	0	11%	7,147	1,119	73%
2031	6,605	0	11%	7,405	1,159	73%
2032	6,811	0	11%	7,636	1,195	73%
2033	7,063	0	11%	7,918	1,239	73%
2034	7,297	0	11%	8,181	1,281	73%
2035	7,573	0	11%	8,490	1,329	73%
2036	7,838	0	11%	8,787	1,376	73%
2037	8,113	0	11%	9,095	1,424	73%
2038	8,397	0	11%	9,414	1,473	73%
2039	8,692	0	11%	9,744	1,525	73%
2040	8,996	0	11%	10,085	1,578	73%
AAG	3.9%	-	-	3.9%	4.0%	-

Source: NamPower, 2016

Table 51 Namibia's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*3,871*	*597*	*3,871*	*597*
2016	*4,241*	*646*	*4,292*	*625*
2017	4,549	693	4,435	643
2018	4,780	733	4,503	654
2019	4,930	758	4,587	667
2020	5,100	786	4,668	681
2021	5,288	816	4,780	698
2022	5,443	842	4,890	716
2023	5,606	869	5,004	734
2024	5,793	899	5,126	753
2025	5,991	931	4,919	735
2026	6,197	964	5,046	755
2027	6,425	1,001	5,176	775
2028	6,655	1,039	5,305	797
2029	6,895	1,078	5,442	819
2030	7,147	1,119	5,577	841
2031	7,405	1,159	5,722	864
2032	7,636	1,195	5,861	887
2033	7,918	1,239	6,004	911
2034	8,181	1,281	6,150	936
2035	8,490	1,329	6,300	961
2036	*8,787*	*1,376*	6,453	987
2037	*9,095*	*1,424*	6,610	1,014
2038	*9,414*	*1,473*	6,770	1,042
2039	*9,744*	*1,525*	6,935	1,070
2040	*10,085*	*1,578*	7,103	1,099
AAG	*3.9%*	*4.0%*	2.5%	2.5%

Source: NamPower, 2016

A1.8 South Africa

A1.8.1 Load forecast information supplied by the utility

The national electricity demand forecast in South Africa is described in the "Transmission Demand Forecast Report for Planning Purposes for the Period 2015-2026" and it was developed in 2015 by Eskom. Table 52 summarises the national electricity demand forecast and comments on the methodology and the main drivers of the demand. The review of the national electricity demand forecast is presented in Section A1.8.2 and the updated electricity demand forecast which will be used in the 'SAPP Regional Generation and Transmission Expansion Plan' is presented in Section A1.8.3.

Table 52 South Africa's national electricity demand forecast

Item	**Demand forecast information provided by utility – *final version in last sub-section***												
National demand forecast		2015		2020		2025		2030		2035		2040	
		Tw	GW	TWh	GW	TWh	GW	TWh	GW	TWh	GW	TWh	GW
	Con.	226.7	43.7	252.4	48.2	271.9	54.3	302.0	58.3	336.6	62.0	368.1	65.4
	Uncon.	227.7	34.7	278.0	43.1	318.3	53.2	366.4	58.3	425.9	62.0	486.3	65.4
	LF (Con.)	0.59		0.60		0.57		0.59		0.62		0.64	
	LF (Uncon.)	0.75		0.74		0.68		0.72		0.78		0.85	
Forecast period	The national demand forecast is a medium to long term forecast covering the period 2015-2040. Two forecast scenarios are developed: the constrained forecast representing the expected reality and the unconstrained forecast representing an economic growth that would enable South Africa to move from a developing country to a developed country status.												
Methodology used	The national demand forecast is broken down by region and consumer sectors to: urban households, rural households, agriculture, construction, mining, manufacturing and services. The national demand forecast methodology follows an end user approach and it uses a trend line analysis to forecast underlying parameters. The effect of demand-side management measures is not included in the electricity demand forecast; suppressed demand is taken into account. Exports are included in the national demand forecast.												
Forecasting parameters	The main parameter used in the demand forecast is the growth rate of the Gross Value Added (GVA) by economic sector by activity by province.												
Main drivers	The main drivers of the electricity demand forecast are the economic activity per province.												

Source: Summary of information from ESKOM

A1.8.2 Review of utility's demand forecast

National demand forecast

The national energy demand forecast was developed for two scenarios and it covers the period 2015-2040:

- Constrained scenario -represents the expected reality with the current energy constraints and low economic growth South Africa is experiencing. The Constrained forecast is accelerated to meet the Unconstrained Forecast by 2024 when additional capacity will be produced from the increased generation fleet and it will unlock economic growth in areas with suppresses demand.
- Unconstrained scenario - the optimistic scenario in line with a combination between the IRP 2010 and economic parameters such as a 5.4% GDP growth. The Unconstrained forecast supports unlocking of economic growth to enable South Africa to move from a developing country to a developed country.

Table 53presents the peak and energy demands electricity forecast for the constrained and the unconstrained scenarios. The average annual demand growth rate is 2.0% for the constrained scenario and 3.1% for the unconstrained scenario. The electricity demand forecast presented in Table 53includesthe transmission and distribution system losses and exports.

Table 53 South Africa's demand forecast 2015-2040

	Constrained scenario					**Unconstrained scenario**				
	Energy demand		Peak demand		LF	Energy demand		Peak demand		LF
	Forecast	Growth rate	Forecast	Growth rate		Forecast	Growth rate	Forecast	Growth rate	
	TWh	%	GW	%	%	TWh	%	GW	%	%
2015	226.7	-	34.7	-	75%	227.7	-	43.7	-	60%
2016	232.6	2.6%	36.3	4.7%	73%	239.1	5.0%	44.6	2.1%	61%
2017	238.3	2.4%	37.9	4.4%	72%	253.5	6.0%	45.5	2.1%	64%
2018	244.3	2.5%	39.6	4.4%	70%	263.4	3.9%	46.5	2.1%	65%
2019	248.7	1.8%	41.3	4.3%	69%	269.1	2.2%	47.2	1.5%	65%
2020	252.4	1.5%	43.1	4.5%	67%	278.0	3.3%	48.2	2.2%	66%
2021	255.0	1.0%	45.1	4.5%	65%	283.7	2.0%	50.1	3.9%	65%
2022	259.0	1.6%	47.2	4.8%	63%	292.6	3.2%	51.6	3.0%	65%
2023	261.6	1.0%	49.2	4.3%	61%	298.4	2.0%	52.6	2.0%	65%
2024	266.2	1.8%	51.2	3.9%	59%	307.6	3.1%	53.5	1.6%	66%
2025	271.9	2.1%	53.2	3.9%	58%	318.3	3.5%	54.3	1.6%	67%
2026	277.9	2.2%	55.2	3.8%	58%	328.0	3.1%	55.2	1.5%	68%
2027	284.1	2.2%	55.9	1.3%	58%	337.5	2.9%	55.9	1.3%	69%
2028	290.1	2.1%	56.7	1.4%	58%	347.1	2.9%	56.7	1.4%	70%

	Constrained scenario					Unconstrained scenario				
2029	296.2	2.1%	57.5	1.3%	59%	357.0	2.8%	57.5	1.3%	71%
2030	302.0	2.0%	58.3	1.4%	59%	366.4	2.6%	58.3	1.4%	72%
2031	307.9	2.0%	59.0	1.3%	60%	376.0	2.6%	59.0	1.3%	73%
2032	315.8	2.6%	59.8	1.2%	60%	388.4	3.3%	59.8	1.2%	74%
2033	323.6	2.5%	60.5	1.2%	61%	400.8	3.2%	60.5	1.2%	76%
2034	331.2	2.4%	61.3	1.4%	62%	413.5	3.2%	61.3	1.4%	77%
2035	336.6	1.6%	62.0	1.1%	62%	425.9	3.0%	62.0	1.1%	78%
2036	343.9	2.2%	62.7	1.1%	63%	438.7	3.0%	62.7	1.1%	80%
2037	348.8	1.4%	63.5	1.1%	63%	451.8	3.0%	63.5	1.1%	81%
2038	358.9	2.9%	64.2	1.2%	64%	461.2	2.1%	64.2	1.2%	82%
2039	363.8	1.4%	64.9	1.1%	64%	474.0	2.8%	64.9	1.1%	83%
2040	368.1	1.2%	65.4	0.7%	64%	486.3	2.6%	65.4	0.7%	85%

Source: Eskom, 2016

Forecasting methodology

The South Africa national demand forecast is calculated as the sum of the individual demand forecasts developed for each of the nine provinces. The demand forecast developed for each province is based on a detailed forecast of the economy using a disaggregated model that has nine sectors further classified into primary, secondary and tertiary activities. The nine identified economic sectors are: the agriculture sector, the mining sector, the manufacturing sector, the electrical sector, the constructions sector, trade, transport, finance and community services. While the exact methodology used for the forecast is not that clearing the "Transmission Demand Forecast Report for Planning Purposes for the Period 2015-2026" report, it is evidently based on a relationship between power demand and growth in value added in various sectors of economic activity. The main indicator used to estimate the load growth is the growth of the Gross Value Added (GVA) from each economic activity per province.

For the peak demand forecast the contribution of each province to the national peak demand forecast is also taken into account as the unique peak of each area does not occur at the same time as the national system peak.

The final peak demand forecast includes the power station consumption from the grid, the demand from each province, the system losses and exports. The estimated exports and the estimated technical losses are added on top of the estimated constrained and unconstrained demand forecast.

It is not clear from the "Transmission Demand Forecast Report for Planning Purposes for the Period 2015-2026" report if the forecast takes into account demand-side measures.

Parameters used in the demand forecast

The main parameter used in the demand forecast is the growth rate of the Gross Value Added (GVA) by economic sector by activity by province. The relationship between the

GVA growth rate and the load growth rate is not presentedin the "Transmission Demand Forecast Report for Planning Purposes for the Period 2015-2026" report. However, the report provides information for the forecast growth rate of the Gross Value Added (GVA) by economic sector by activity by province. The table indicates the parameters used in the constrained and the unconstrained demand forecasts, namely, the average annual GVA growth forecast for each province, the average annual GDP growth forecast per province and the average annual load demand growth forecast per province for the period 2015 to 2026. The constrained forecast average annual growth is higher than that of the unconstrained forecast growth rate in eight of the nine provinces for a period of time. This is because the constrained forecast has to grow at a higher rate for a period of time in order to catch up with the unconstrained values when sufficient generation capacity will unlock suppressed demand.

Table 54 Disaggregated GVA growth by region

	Unconstrained scenario			**Constrained scenario**		
	Average annual GVA growth forecast	Average annual GDP growth forecast	Average annual load demand growth	Average annual GVA growth forecast	Average annual GDP growth forecast	Average annual load demand growth
Eastern Cape	4.0%	2.9%	1.4%	2.8%	1.7%	2.4%
Free State	3.6%	2.6%	1.8%	2.2%	1.8%	2.6%
Gauteng	4.1%	2.9%	1.6%	3.3%	2.2%	2.1%
KwaZulu-Natal	4.0%	2.8%	1.4%	3.1%	1.8%	2.3%
Limpopo	3.9%	2.7%	5.2%	2.2%	2.7%	5.3%
Mpumalanga	3.6%	2.5%	2.0%	2.3%	2.3%	2.2%
Northern Cape	3.9%	2.7%	1.7%	1.8%	1.6%	2.0%
North-West	3.9%	2.6%	3.4%	1.8%	3.7%	2.4%
Western Cape	4.1%	2.9%	3.0%	3.3%	2.4%	3.8%

Source: Eskom, 2016

To estimate the volumes of electricity exports during the forecast period it is assumed that exports will remain at the 2015 levels of around 2 GW even after the contractual obligations terminate. It is mentioned that these loads are not going to disappear at the end of the contracts, but no additional export loads were assumed.

Table 55 South Africa's contracted exports (GW)

	Total exports (contractual values)	**Botswana**	**Mozambique**	**MOZAL**	**Swaziland**	**Namibia**	**Zambia**
2015-2040	1.98	0.3	0.3	0.95	0.25	0.18	0

Source: Eskom, 2015

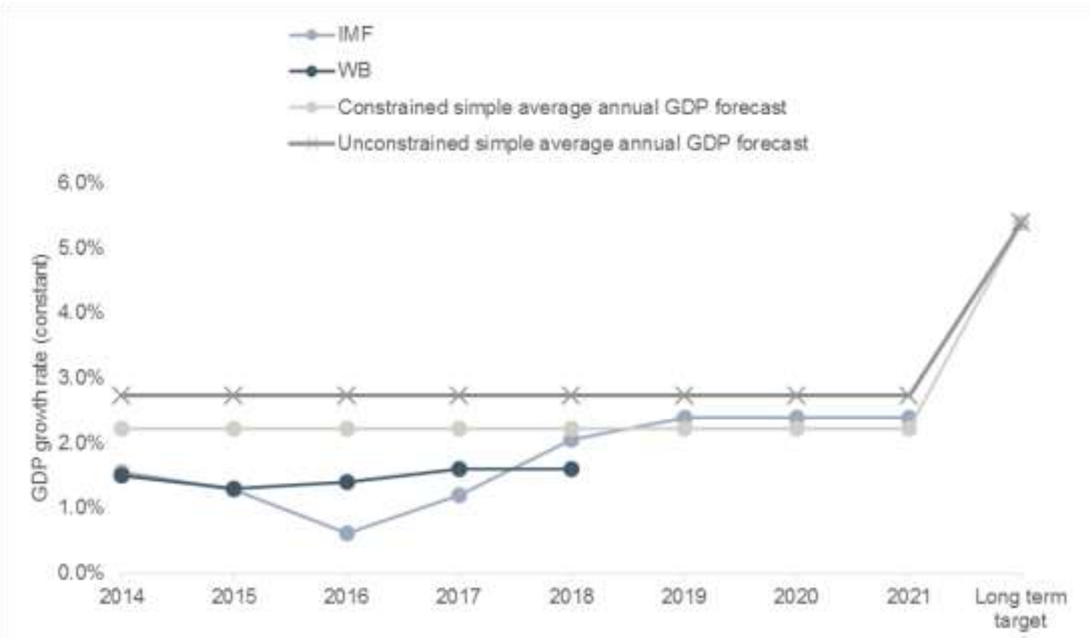
The power station loads are treated as known and the transmission losses are based on previous calculations and future expectations. The power station's auxiliary demand is assumed at 26.3MW annually and the transmission system losses are 3% of the total maximum demand.

Comments on the demand forecast

The discussion about methodology in the "Transmission Demand Forecast Report for Planning Purposes for the Period 2015-2026" focuses more about the spatial disaggregation of the load forecasts at provincial and substation levels than about the basis for the economic growth assumptions that are used. The implied resulting overall growth in national GDP is not calculated. It would be important to know whether the national average implied in the demand forecast is above or below the national GDP target.

The demand forecast report mentions that the unconstrained forecast assumes an annual average GDP growth rate of 5.4%. The average GDP growth rate of 5.4%would enable South Africa to move from a developing country to a developed country. However, the current economic indicators in South Africa make this growth rate look unrealistic in the short to medium term. The assumed annual average GDP growth rate of the unconstrained forecast has an impact on the constrained forecast as the constraint forecast is accelerated to meet the unconstrained forecast in 2024. Figure 9 compares the annual GDP growth rate forecast developed by the IMF and the WB with the simple average annual GDP growth rate forecast used in the constrained and the unconstrained scenarios. The simple average annual GDP growth rate forecast presented in the figure below is the simple average of the average annual GDP growth rates forecasts of the provinces. The resulting overall national growth in GDP used in the demand forecasts or weighting factors to calculate national growth in GDP were not available. The GDP growth rates used in the demand forecast seem to be optimistic in comparison to the current state of the economy and the short term GDP projections from the IMF and the WB.

Figure 9 South Africa's GDP growth rate forecast



Source: Eskom, WB, IMF

The peak demand projections are assumed to be independent of the energy demand. Calculating load factors from the figures provided, it appears that significant changes in system load factor are implicitly being assumed – see Table 53 above. These variations cannot be explained by factors such as changes in the share of domestic customers due to improved electricity access for households or by changes in industrial demand due contraction of energy intensive industries.

The constrained and the unconstrained scenarios assume a different actual value for the base year of the demand forecast. The unconstrained forecast assumes a theoretical value whereas the constrained forecast assumes the actual recorded value. The actual values should be the same in all cases.

After communicating with ESKOM staff we have received an updated electricity demand forecast to be used for the PLEXOS modelling on 19 July 2016. We will use the updated forecast for the completion Table 56. However, we did not receive any information regarding the methodology used for the updated forecast, but will assume that it is an update to the previous forecast and based on the same methodology. Furthermore, we received information that the forecast was still in 'draft' form and can still be slightly altered.

A1.8.3 Updates to base forecast and assumptions for low forecast

After removing export demand, which forms part of the importers' national demand, the forecast received from ESKOM in July 2016 was used for the PLEXOS modelling up to and including the June 2017 workshop.

To take account of the economic growth implications of the downgrading of the country's bond status, the ESKOM demand forecast was reduced. The revised figures received in July 2017 were used for the modelling for the Final Report.

The 'low' demand forecast is based on an assumption of still lower economic growth. The annual average rate of growth in maximum demand in the base demand forecast is 2.5% per annum. In the low forecast, this is reduced to 1.9% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 56. The corresponding figures for the low forecast are given in Table 57. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 56 South Africa's updated demand forecast excluding exports

	Energy sent out (GWh)[5]	Peak demand sent out (GW)	Load factor (%)
2015	215,693	32.8	75%
2016	215,838	32.9	75%
2017	228,633	34.8	75%
2018	237,263	36.1	75%
2019	246,845	37.6	75%
2020	254,042	38.7	75%
2021	262,094	39.9	75%
2022	269,634	41.0	75%
2023	276,608	42.1	75%
2024	284,279	43.3	75%
2025	292,593	44.5	75%
2026	301,498	45.9	75%
2027	310,946	47.3	75%
2028	318,256	48.4	75%
2029	325,360	49.5	75%
2030	332,219	50.6	75%
2031	338,796	51.6	75%
2032	345,061	52.5	75%
2033	350,985	53.4	75%
2034	356,543	54.3	75%
2035	361,717	55.1	75%
2036	366,488	55.8	75%
2037	370,843	56.4	75%
2038	374,769	57.0	75%
2039	378,258	57.6	75%
2040	382,052	58.2	75%
AAG	**2.3%**	**2.3%**	-

Source: ESKOM, 2016

[5] Energy sent out includes technical and non-technical losses.

Table 57 South Africa's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (GW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (GW)
2015	*215,693*	*32.8*	*215,693*	*32.8*
2016	*215,838*	*34.0*	*223,492*	*34.0*
2017	228,633	34.8	228,633	35.7
2018	237,263	36.1	237,263	36.4
2019	246,845	37.6	246,845	37.2
2020	254,042	38.7	254,042	37.9
2021	262,094	39.9	262,094	38.8
2022	269,634	41.0	269,634	39.6
2023	276,608	42.1	276,608	40.4
2024	284,279	43.3	284,279	41.3
2025	292,593	44.5	292,593	42.2
2026	301,498	45.9	301,498	43.0
2027	310,946	47.3	310,946	43.9
2028	318,256	48.4	318,256	44.7
2029	325,360	49.5	325,360	45.5
2030	332,219	50.6	332,219	46.3
2031	338,796	51.6	338,796	47.1
2032	345,061	52.5	345,061	47.8
2033	350,985	53.4	350,985	48.6
2034	356,543	54.3	356,543	49.2
2035	361,717	55.1	361,717	49.9
2036	366,488	55.8	366,488	50.5
2037	370,843	56.4	370,843	51.0
2038	374,769	57.0	374,769	51.5
2039	378,258	57.6	378,258	52.0
2040	382,052	58.2	382,052	52.4
AAG	2.3%	2.3%	2.3%	1.9%

Source: ESKOM, 2016

A1.9 Swaziland

A1.9.1 Load forecast information supplied by the utility

The national electricity demand forecast in Swaziland was developed in 2015 by Swaziland Electricity Company (SEC) and is presented in the *Swaziland Electricity Company Demand Forecast Update* report. Table 27 summarises the national electricity demand forecast and comments on the methodology and the main drivers of the demand. The review of the national electricity demand forecast is presented in Section A1.9.2 and the updated electricity demand forecast which will be used in the 'SAPP Regional Generation and Transmission Expansion Plan' is presented in Section A1.9.3.

Table 58 Swaziland's demand forecast summary

Item	Demand forecast information provided by utility – *final version in last sub-section*												
National demand forecast		2015		2020		2025		2030		2035		2040	
		GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW
	Low	1,053	245	1,304	279	1,586	330	1,700	365				
	Likely	1,055	248	1,337	283	1,661	339	1,810	381				
	High	1,057	249	1,371	289	1,749	352	1,978	410				
	LF	0.55		0.61		0.64		0.62					
Forecast period	The national demand forecast is a long term forecast covering the period 2015-2034.												
Methodology used	Forecast of spatial development across the country, analysis of future point loads and forecast growth in household demand												
Forecasting parameters	Socio-economic and spatial data parameters												
Main drivers	Economic growth parameters per sub-place level, Actual Development initiatives, and Electrification were developed along the guidelines provided by the department of Energy and inputs from SEC												

Source: Swaziland Electricity Company Demand Forecast Update, SEC 2016

A1.9.2 Review of utility's demand forecast

National demand forecast

The electricity demand forecast is developed for three scenarios and it covers the period 2014-2034.The starting year of the demand forecast is 2014. The peak demand and the energy demand for 2014 reflects the actual recordings for 2014. Table 59 below presents SEC's peak and energy demand forecast for the low, the likely and the high scenarios. The peak demand is expected to grow per annum at an average rate of 3%, 4% and 5% in the low, likely and high scenarios, respectively. The total energy consumption excluding losses in 2014 was 992 GWh. The energy demand is expected to grow on average per annum by 2.8%, 3.2% and 3.8% in the low, likely and high scenarios, respectively. The peak demand forecast presented in Table 59 above includes system losses. However, the energy demand forecast represents energy sales.

Table 59 Swaziland's national electricity demand forecast

		Power (MW)			Energy (GWh) - excl. losses		
		Low	Likely	High	Low	Likely	High
Actual	2014	268.2	268.2	268.2	992	992	992
Forecast	2015	278.4	281.8	278.4	1,053	1,055	1,057
Forecast	2016	287.5	286.4	287.5	1,074	1,078	1,083
Forecast	2017	293.2	292.0	295.5	1,107	1,116	1,125
Forecast	2018	298.9	301.1	303.4	1,163	1,178	1,194
Forecast	2019	306.8	310.2	314.8	1,232	1,256	1,280
Forecast	2020	317.0	321.6	328.4	1,304	1,337	1,371
Forecast	2021	328.4	334.1	342.0	1,377	1,419	1,462
Forecast	2022	339.8	347.7	356.8	1,448	1,499	1,552
Forecast	2023	352.3	360.2	370.5	1,508	1,568	1,632
Forecast	2024	363.6	373.9	385.2	1,552	1,620	1,694
Forecast	2025	375.0	385.2	400.0	1,586	1,661	1,749
Forecast	2026	384.1	396.6	414.8	1,615	1,697	1,800
Forecast	2027	394.3	408.0	428.4	1,641	1,730	1,848
Forecast	2028	402.3	417.0	442.0	1,664	1,760	1,895
Forecast	2029	409.1	425.0	454.5	1,683	1,786	1,938
Forecast	2030	414.8	433.0	465.9	1,700	1,810	1,978
Forecast	2031	418.8	438.1	475.0	1,713	1,830	2,015
Forecast	2032	422.7	443.2	484.1	1,726	1,849	2,051
Forecast	2033	425.6	446.6	492.0	1,736	1,865	2,085
Forecast	2034	428.4	450.0	500.0	1,746	1,880	2,119

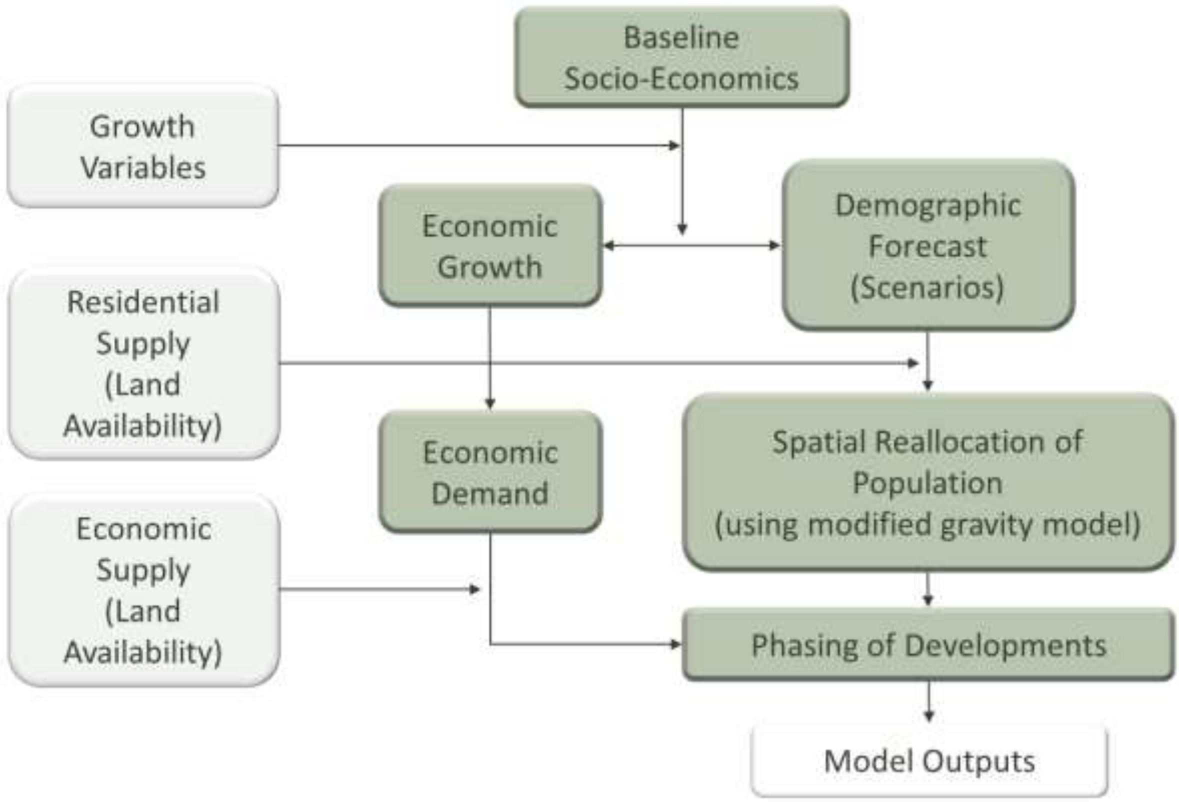
Source: Swaziland Electricity Company Demand Forecast Update, SEC 2016

Forecasting methodology

The methodology is essentially bottom up, encompassing three elements – a forecast of spatial development across the country, analysis of future point loads and forecast growth in household demand as access to electricity is increased over time. The demand forecast is developed separately for each area and for each consumer category included in the area. The identified consumer categories were the agriculture sector, the commercial sector, the communities (including hospitals, churches, etc.), educational facilities, industrial customers, residential consumers and the utilities. The aim of the demand forecast is to determine the present and future electricity requirements of electrical end users by area and then aggregate the demand of each customer and each area to form the national electricity demand forecast.

The main underlying parameters of the demand forecast for each consumer category were socioeconomic indicators and the load characteristics of each consumer category. Regarding the socio-economic background, the demand forecast is "based on the predicted spatial location of future load, guided by aspects such as the Urban and District Development Plans, predicted future developments as well as the socio-economic perspective of Swaziland". This approach is illustrated in the diagram below.

Figure 10 Spatially based methodology used for Swaziland demand forecast



Source: Swaziland Electricity Company Demand Forecast Update, SEC 2016

Parameters used in the demand forecast

The main socioeconomic indicators that were used to develop the electricity demand forecast demand forecast were the GDP growth rate per economic activity per region, the population size and growth rate per region and the population and household income per region. Even though the forecast report presents a detailed analysis for the historical indicators, the underlying socioeconomic parameters of the demand forecast were not available.

A separate report includes the population forecast that was used in the demand forecast. The population forecast and the average annual population growth rate per period is present in Table 60 below.

Table 60 Swaziland population forecast

Year	Population forecast	Population annual average growth rate per period
2015	1119376	1.2%
2020	1185448	1.0%
2025	1247451	0.9%
2030	1303091	

Source: Swaziland Electricity Demand Forecast Socio-Economic Modelling: Draft Report, SEC 2014.

Comments on the demand forecast

The demand forecast aims to identify the socioeconomic growth in each area and from the economic growth to forecast the electricity demand per economic activity. Thus, on an aggregate level, the annual energy demand forecast growth rate would be expected to follow the annual national GDP growth rate forecast, as the forecast methodology aims to correlate electricity demand with economic activity.

Figure 11 compares the energy demand forecast annual growth rate developed by SEC with the annual GDP growth rate forecast developed by IMF and the World Bank. It is evident that the energy demand growth rate does not follow the GDP growth rate projections developed by IMF and the WB. The discrepancies between the GDP and the energy demand growth rate forecast can be explained from the assumed electrification rates of the demand forecast.

Since 2010, access to electricity has increased significantly, particularly in rural areas which are reported to have reached 55% access by 2014. The access rate for the country as a whole is approaching 65%. Current estimates suggest that network coverage is approximately 85%. Thus the electrification of new areas might be contributing to higher energy demand growth rates in comparison to the GDP growth rate forecast, as new customers connect to the grid.

Figure 11 Swaziland's GDP growth rate forecast vs energy demand growth rate

Source: IMF 2016; WB 2016; Swaziland Electricity Company Demand Forecast Update, SEC 2016

The consumption mix of electricity consumers is expected to change within the forecast period. The forecast consumption mix in 2015 and in 2030 is presented in Table 61 below. It is expected that the economic growth will increase the demand of commercial consumers. The share of the commercial demand in 2015 is estimated 9.6%, whereas share of the commercial demand in 2030 is forecasted to be 15.7%. This change in the consumption mix should be reflected in the load factor, which is increasing as the commercial customers consume more electricity.

Table 61 Swaziland forecast consumption mix

	Commercial	Domestic	Industrial	Irrigation	Other
2015	9.60%	34.02%	48.33%	7.92%	0.12%
2031	15.73%	33.19%	45.33%	4.67%	1.08%

Source: Swaziland Electricity Company Demand Forecast Update, SEC 2016

Overall, SEC's forecast seems to reflect the economic development of the country and the subsequent growth in electricity demand. The adopted methodology examines in detail the electricity demand by region by accounting the individual load characteristics of each region and each consumer category. The likely scenario is assumed to be the most representative scenario and will be adopted for the SAPP pool development plan.

The energy demand forecast developed by SEC does not include technical and commercial losses. To calculate the sent out energy demand forecast the assumed technical and commercial losses have to be added to the energy sales forecast. The average system losses for 2012 were 15.5% according to: https://www.usea.org/sites/default/files/event-/Swaziland%20Power%20Sector.pdf. We have assumed the same level of losses throughout the forecasting period. However, it is not clear whether the system losses represent technical and non-technical losses or only technical losses.

Currently, Swaziland does not plan to export electricity to the SAPP and mainly relies on energy imports from South Africa to cover the national electricity demand requirements. No exports were therefore expected throughout the forecasting period.

A1.9.3 Updates to the forecast

Below is the updated Swaziland electricity demand forecast, based on the 'likely' scenario presented in *Swaziland Electricity Company Demand Forecast Update* report. The forecast covers the period 2015-2035. We have extrapolated the forecast to the year 2040 by using the average growth rate for *peak demand sent out* and *energy sent out* for the period 2030-2035, 1.1% and 1% respectively.

The 'low' demand forecast is based on an assumption of lower economic growth arising from continuation of low petroleum prices and a slow-down in the pace of infrastructural investment in the country. The annual average rate of growth in maximum demand in the base demand forecast is 2.3% per annum. In the low forecast, this is reduced to 1.6% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 62. The corresponding figures for the low forecast are given in Table 63. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 62 Swaziland's updated electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out(MW)	Load factor (%)
2015	992	0	15%	1,141	236	54%
2016	1,055	0	15%	1,213	248	54%
2017	1,078	0	15%	1,240	252	56%
2018	1,116	0	15%	1,283	257	57%
2019	1,178	0	15%	1,355	265	58%
2020	1,256	0	15%	1,444	273	60%
2021	1,337	0	15%	1,538	283	62%
2022	1,419	0	15%	1,632	294	63%
2023	1,499	0	15%	1,724	306	64%
2024	1,568	0	15%	1,803	317	65%
2025	1,620	0	15%	1,863	329	65%
2026	1,661	0	15%	1,910	339	64%
2027	1,697	0	15%	1,952	349	64%
2028	1,730	0	15%	1,990	359	63%
2029	1,760	0	15%	2,024	367	63%
2030	1,786	0	15%	2,054	374	63%
2031	1,810	0	15%	2,082	381	62%
2032	1,830	0	15%	2,104	386	62%
2033	1,849	0	15%	2,126	390	62%
2034	1,865	0	15%	2,144	393	62%
2035	1,880	0	15%	2,162	396	62%
2036	1,899	0	15%	2,184	401	62%
2037	1,919	0	15%	2,207	405	62%
2038	1,939	0	15%	2,230	410	62%
2039	1,959	0	15%	2,253	415	62%
2040	1,979	0	15%	2,276	419	62%
AAG	**2.8%**	**-**	**-**	**2.8%**	**2.3%**	**-**

Source: SEC, 2016

Table 63 Swaziland's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*1,141*	*236*	*1,084*	*225*
2016	*1,213*	*248*	*1,148*	*230*
2017	1,240	252	1,161	233
2018	1,283	257	1,177	236
2019	1,355	265	1,231	241
2020	1,444	273	1,301	246
2021	1,538	283	1,369	252
2022	1,632	294	1,436	259
2023	1,724	306	1,499	266
2024	1,803	317	1,551	273
2025	1,863	329	1,584	280
2026	1,910	339	1,610	286
2027	1,952	349	1,630	291
2028	1,990	359	1,647	297
2029	2,024	367	1,664	302
2030	2,054	374	1,679	306
2031	2,082	381	1,692	310
2032	2,104	386	1,704	312
2033	2,126	390	1,716	315
2034	2,144	393	1,726	316
2035	2,162	396	1,737	318
2036	2,184	401	1,748	321
2037	2,207	405	1,760	323
2038	2,230	410	1,772	326
2039	2,253	415	1,784	328
2040	2,276	419	1,796	331
AAG	2.8%	2.3%	2.0%	1.6%

Source: SEC, 2016

A1.10 Tanzania

A1.10.1 Load forecast information supplied by the utility

Tanzania's National Demand Forecast was prepared by the Ministry of Energy and Minerals. It is presented in 'Power System Master Plan 2012 Update' document dated in May 2013. The forecast provides an energy demand forecast as well as a system peak load forecast for the period 2015-2035. Table 64 summarizes the forecasts and the methodology. In Section A1.10.2 a review of the methodology and underlying parameters is provided. The final sub-section provides the energy forecast used for the SAPP Pool Plan, which is based off of the available energy demand forecast for Tanzania.

Table 64 Tanzania's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*						
Country's demand forecast	Base case	2015	2020	2025	2030	2035	2040
	Energy (GWh)	11,246	19,607	27,139	36,543	47,424	-
	Power (MW)	2,073	3,547	4,690	6,040	7,589	-
Forecast period	The forecast covers the period 2010-2035 with 2010 as a base year.						
Methodology used	The forecast builds on a trend line analysis for regional forecasts. The regional forecasts are then aggregated to form the national forecast. The forecast breaks the customers down into three tariffs categories: residential and light industrial and commercial consumption; low voltage consumption; and high voltage consumption. An econometric model was also created to check the validity of the trend line analysis forecast. The forecast used the year 2010 as the base but tries to model all the national demand. Suppressed demand is therefore included and load shedding is added to 2010 figures, which gives the figure used as a basis for the forecast. The forecast takes demand side management into account under all three tariff categories. Transmission and distribution losses are shown.						
Forecasting parameters	The forecast uses a trend relationship between external drivers and electricity sales based on the period 1986-2010. GDP growth, demographic growth and new connection rates are used for the forecast.						
Main drivers	Growth comes mainly from increased activity in the industrial sector and achieving a high rate of new household connections.						

Source: Summary of information from Tanesco

A1.10.2 Review of utility's demand forecast

National demand forecast

The forecast is prepared using an analysis of the relationship between external drivers and electricity sales over the period 1985-2010 and then forecasted until 2035. An econometric forecast was also undertaken to validate the trend line analysis forecast. The forecast sets out to forecast demand in an unconstrained system. 2010 is used as the base year for the forecast but takes account of suppressed demand and load shedding. The analysis is undertaken on a regional basis and the national demand forecast aggregated from the data.

The forecast is based on electricity growth in an unconstrained system, so a higher than average GDP growth was assumed for the forecasting period due to projected increased economic activity from no suppressed electricity demand.

The Tanzania national demand forecast is presented in Table 65. The forecast includes gross generation of energy and thus including parasitic losses and transmission losses. Table 66 shows an overview of the energy generated and different losses. As mentioned previously the forecast is based on an unconstrained 2010 demand and data for 2011 and 2012 are estimates.

Table 65 Tanzania's demand forecast 2010-2035 – Base scenario

	Gross generation	**Peak demand (MW)**		**Breakdown of tariff**			**Electrification rates**
	Energy (GWh)	Coincident peak	Sum of peaks	T1	T2	T3	
2010*	5,653	1054	1062	2024	593	1,559	14.00%
2011	5,908	1109	1117	2126	598	1,641	14.00%
2012	6,085	1131	1139	2258	607	1,732	15.00%
2013	7,332	1355	1365	2661	896	2,094	18.00%
2014	9,200	1692	1704	3094	1234	2,905	21.00%
2015	11,246	2073	2089	3549	1576	3,749	24.00%
2016	13,520	2504	2522	4042	1803	4,418	
2017	15,494	2877	2898	4536	2031	5,086	
2018	17,194	3181	3204	5029	2258	5,755	
2019	18,322	3349	3374	5523	2486	6,423	
2020	19,607	3547	3573	6017	2713	7,092	37.00%
2021	20,943	3753	3781	6677	2891	7,538	
2022	22,424	3980	4009	7337	3068	7,985	
2023	24,000	4222	4253	7997	3246	8,432	
2024	25,514	4450	4483	8658	3423	8,878	
2025	27,139	4690	4724	9318	3601	9,325	51.00%
2026	28,860	4943	4979	10183	3833	9,844	
2027	30,689	5210	5248	11048	4066	10,363	
2028	32,635	5491	5531	11912	4298	10,882	
2029	34,560	5764	5806	12777	4531	11,401	
2030	36,543	6041	6085	13642	4763	11,920	66.00%

	Gross generation	Peak demand (MW)		Breakdown of tariff			Electrification rates
2031	38,646	6331	6378	14679	5073	12,524	
2032	40,836	6630	6679	15716	5383	13,129	
2033	43,030	6928	6979	16753	5694	13,733	
2034	45,359	7237	7290	17790	6004	14,337	
2035	47,724	7589	7645	18828	6314	14,942	78.00%

Source: Power System Master Plan 2012 update. May 2013

Table 66 provides an overview of the energy generated and the losses through the supply chain to the end-user. Transmission and distribution losses decrease from 24% in 2010 to 15% in 2035 reflecting loss reduction measures assumed in the forecast.

Table 66 Tanzania's energy losses – base scenario

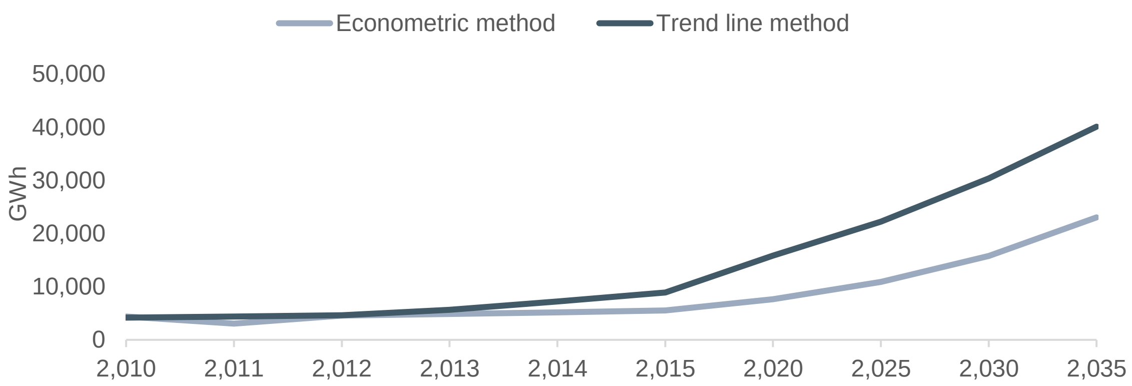
	Generation [GWh]			Losses [GWh]				
	Gross generation	Parasitic load	Net generation	Transmission losses	Distribution losses	Losses (%)	Recovered load shedding	**Total sales**
2010*	5,653	62	5,591	291	1,027	24%	98	4,175
2011	5,908	65	5,843	306	1,074	24%	98	4,365
2012	6,085	67	6,019	331	993	22%	98	4,597
2013	7,332	81	7,251	391	1,111	21%	98	5,651
2014	9,200	101	9,099	481	1,287	19%	98	7,233
2015	11,246	124	11,122	575	1,576	19%	98	8,874
2020	19,607	216	19,391	883	2,589	18%	98	15,821
2025	27,139	299	26,840	1,160	3,339	17%	98	22,244
2030	36,543	402	36,141	1,571	4,148	16%	98	30,325
2035	47,724	525	47,199	2,057	4,961	15%	98	40,083

Source: Power System Master Plan 2012 update. May 2013

An econometric forecast was made to validate the trend line method used to generate the main forecast. The forecast was made for each tariff category based on historical data and disaggregated GDP growth figures. The correlation used for the forecasting was between total sales and GDP at constant 2001 TSh prices. Table 67 provides a comparison between the two forecasts. While the difference between the two forecasts reaches 108% the forecasts' authors considered it to validate the trend line analysis approach due to the additional demand from electrification programs, not represented in the econometric analysis.

Table 67 Comparison of forecasts

	Trend line analysis					Econometric analysis				Difference	
	T1	T2	T3	T1+T2+T3	Global	T1	T2	T3	Global	+/-	%
2010	2,187	600	1,604	4,391	4,391	2,024	593	1,559	4,175	-216	5%
2011	1,444	414	1,193	3,051	3,051	2,126	598	1,641	4,365	1,314	43%
2012	2,140	561	1,737	4,437	4,552	2,258	607	1,732	4,597	45	1%
2013	2,272	586	1,876	4,735	4,853	2,661	896	2,094	5,651	798	16%
2014	2,413	614	2,026	5,053	5,175	3,094	1,234	2,905	7,233	2,059	40%
2015	2,564	643	2,187	5,394	5,518	3,549	1,576	3,749	8,874	3,356	61%
2020	3,485	826	3,198	7,509	7,621	6,017	2,713	7,092	15,821	8,201	108%
2025	4,919	1,120	4,785	10,824	10,893	9,318	3,601	9,325	22,244	11,351	104%
2030	7,063	1,569	7,244	15,876	15,784	13,642	4,763	11,920	30,325	14,541	92%
2035	10,237	2,246	11,048	23,531	23,025	18,828	6,314	14,942	40,083	17,058	74%



Source: Power System Master Plan 2012 update. May 2013

Forecasting methodology

The national demand forecast was created using a trend line analysis on 25 years' worth of historical data. The forecast was created at a regional level and then aggregated to the national level. A forecast based on econometric analysis was then developed to validate the original trend line forecast's validity. As presented in the previous section the two can be reconciled once account is taken of the expected demand from scheduled electrification programs. This conclusion was presented by the forecasts' authors and taken to validate the forecast.

The trend line analysis builds on the adjusted 2010 data and covers the period 2011-2035. The forecast offers three scenarios:

❑ low case – business as usual and follows historical trends, electrification rates at 75%;

- base case – Tanzania is assumed to be a middle income country by 2025 with some emerging high demand industry sector, electrification rates 75%;
- high case -emerging high demand industry sector, electrification rates of 100%.

The regional forecasts were constructed taking into account variable population growth, electrification programs, additions of new industrial loads and the interconnection of isolated grids. The parameters, as they were presented, will be provided in the next section.

The forecast assumes that all isolated grids will become interconnected by 2019 and thus affect sales in each region.

In order to analyse historical data and project future demand, the customers where divided by consumption into three categories.

- T1 – A combined category for general use; residential, light commercial, light industrial and public lighting.
- T2 – Category for low voltage users, excluding customers in T1.
- T3 – High voltage customers; High intensive supply energy, agriculture, mining and National Urban Water Authority (NUWA).

The forecast assumes that the forecasting period will be split into three growth periods; short-term 2012-2017 with high GDP growth, medium-term covering 2018-2025 with moderate growth, and long-term 2026-2036 where growth rate will be similar to middle-income countries.

The forecast includes DSM programmes for all tariff categories. However, it is assumed that new loads have taken DSM into account when organising and designing each project.

For the econometric forecast used for validation of the national demand forecast, the correlation between total GDP and energy sales. The forecast was made for each customer category and GDP data disaggregated by sectors. This approach simply assumes that growth will continue as it has in the past and fails to take into account rapid increase of new household connections, due to electrification programs, and the addition of new large loads. While the forecasts' authors were expecting the econometric approach to yield lower results tan the trend-line approach, it gives information on the organic growth in the system.

Parameters used in the demand forecast

The parameters used in the national demand forecast are:

- GDP
- Demographic data by regions
- New connection rates and governmental targets for electrification programs
- New loads that will come online during the forecasting period

The GDP data used for the forecast is historical data from Tanzania and estimates for the years 2011 and 2012. As mentioned in the previous section, the forecasting period will be split up into different growth periods based on 14 years of historical data. The GDP growth was very stable throughout the historical period and the results and forecasted data are presented in Table 68. The table also provides historical data from the IMF to compare with estimates on the forecast growth rates.

Table 68 GDP forecasts and historical data

	High case	Base case	Low case	IMF (historical)
Four-year growth	7.0%	6.8%	6.6%	6.4%
Eight-year growth	7.2%	6.9%	6.3%	6.3%
Ten-year growth	7.3%	7.1%	6.7%	6.3%
Fourteen-year growth	7.8%	6.6%	4.8%	5.7%

Source: Power System Master Plan 2012 update. May 2013

Population growth for the forecast was estimated by analysing the growth rates in between the 1988 and 2002 censuses, and assuming the same relationship throughout the forecasting period. This yields an average population growth of 2.7% throughout the period 2011-2035. By comparison the WB estimates a growth of 2.9% for the same period.

For forecasting new connection rates a target of 250,000 new customers a year was used, as per the Master Plan. These targets were set for a period of five years and once finished, new connection rates are forecasted based on historical rates. The three scenarios presented in the forecast all assume a varying level of implementation of this target. The high scenario assumes the target will be met and 250,000 new connections will be achieved at the end of the five-year plan. The medium scenario assumes that 85% will be achieved, or 212,500 new connections. The low case assumes only 75% success, or 187,500 new connections.

New mining and industrial loads were identified by surveying regions, investors and ministries. The projects were assigned to their region's forecast, and assigned to a scenario based on the probability.

Comments on the demand forecast

The base case suggests a target electrification rate of 75% by the end of the forecasting period. This target is backed by public policy with the program recently gaining funding to aid in installation, reinforcing that the base case is the most likely scenario for reaching electrification targets. The base case will therefore be used for Table 69.

The 2012P PSMP update does not quantify exports for the forecasting period but rather identifies current interconnections with neighbouring countries. The main export potential identified is through the Kenya-Ethiopia interlink which anticipates potential imports of up to 200MW in 2016. No contracted export demand is assumed.

Comments on the updated demand forecast received July 2016

We received an updated demand forecast for Tanzania, presenting very different data from what originally provided. The forecast was disaggregated by customer sector and regions and covered the entire forecasting period. We have observed that the forecast assumes very high growth rates throughout the entire forecasting period with an average annual growth of 10%. This is quite unusual for such a long period and we have asked for confirmation that this is in fact the projected electricity demand growth rate.

The forecast actual peak demand to compare with the forecast. For 2015 actual peak demand was 974 MW while the forecasted value for the same year was 1291 MW. We have assumed the difference to represent suppressed demand but are still waiting confirmation from TANESCO.

The forecast provides system losses of 19% which decrease to 11% at the end of the forecasting period. The forecast does not mention whether these losses include non-technical losses or only technical losses (transmission and distribution losses). The 11% losses are quite low if they are to include total system losses (technical and non-technical losses) and would be justifiable against an aggressive loss reduction program. We have asked for clarification but are still waiting on a response.

A1.10.3 Updates to base forecast and assumptions for low forecast

The final figures used in the Pool Plan were drawn from the *Power System Master Plan 2016 Update* (December 2016). For the 'low' demand forecast, more cautious assumptions have been used than the lower demand forecast in the Power System Master Plan, as this still resulted in an annual average growth rate (9.9%) which is very high in relation to historical performance.

The annual average rate of growth in maximum demand in the base demand forecast is 11.4% per annum. In the low forecast, this is reduced to 4.9% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 69. The corresponding figures for the low forecast are given in Table 70. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 69 Tanzania's updated electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)
2015	5,320	0	19%	6,320	974	74%
2016	6,684	0	18%	7,860	1,250	72%
2017	7,727	0	17%	9,010	1,450	71%
2018	8,927	0	16%	10,320	1,680	70%
2019	10,296	0	15%	11,810	1,930	70%
2020	11,948	0	12%	13,430	2,190	70%
2021	13,283	0	12%	14,890	2,430	70%
2022	14,736	0	12%	16,490	2,690	70%
2023	16,356	0	12%	18,270	2,980	70%
2024	18,160	0	11%	20,230	3,300	70%
2025	20,144	0	11%	22,440	3,660	70%
2026	22,154	0	11%	24,680	4,030	70%
2027	24,363	0	11%	27,140	4,430	70%
2028	26,777	0	11%	29,830	4,860	70%
2029	29,425	0	11%	32,780	5,340	70%
2030	32,316	0	11%	36,000	5,870	70%
2031	35,494	0	11%	39,540	6,450	70%
2032	38,968	0	11%	43,410	7,080	70%
2033	42,765	0	11%	47,640	7,770	70%
2034	46,921	0	11%	52,270	8,520	70%
2035	51,472	0	11%	57,340	9,350	70%
2036	56,086	0	11%	62,480	10,190	70%
2037	61,095	0	11%	68,060	11,100	70%
2038	66,544	0	11%	74,130	12,090	70%
2039	72,460	0	11%	80,720	13,160	70%
2040	78,887	0	11%	87,880	14,330	70%
AAG	**11.4%**	**-**	**-**	**11.1%**	**11.4%**	**-**

Source: TANESCO, 2016

Table 70 Tanzania's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*6,320*	*974*	*6,067*	*935*
2016	*7,860*	*1,250*	*6,451*	*1,026*
2017	9,010	1,450	6,819	1,097
2018	10,320	1,680	7,206	1,173
2019	11,810	1,930	7,643	1,249
2020	13,430	2,190	8,108	1,322
2021	14,890	2,430	8,487	1,385
2022	16,490	2,690	8,886	1,450
2023	18,270	2,980	9,303	1,517
2024	20,230	3,300	9,737	1,588
2025	22,440	3,660	10,200	1,664
2026	24,680	4,030	10,636	1,737
2027	27,140	4,430	11,099	1,812
2028	29,830	4,860	11,589	1,888
2029	32,780	5,340	12,089	1,969
2030	36,000	5,870	12,599	2,054
2031	39,540	6,450	13,134	2,143
2032	43,410	7,080	13,694	2,233
2033	47,640	7,770	14,274	2,328
2034	52,270	8,520	14,882	2,426
2035	57,340	9,350	15,507	2,529
2036	62,480	10,190	16,110	2,627
2037	68,060	11,100	16,735	2,729
2038	74,130	12,090	17,384	2,835
2039	80,720	13,160	18,060	2,944
2040	87,880	14,330	18,754	3,058
AAG	11.1%	11.4%	4.6%	4.9%

Source: TANESCO, 2016

A1.11 Zambia

A1.11.1 Load forecast information supplied by the utility

Zambia's National demand forecast is presented in the Excel file 'ZESCO -Forecasted Demand 2016-2030.xls'. The forecast includes energy demand for the period 2016-2030 and hourly average peak demand for the same period.

The Zambia Power System Development Master Plan (PSDMP) from 2010 includes peak load forecast and an energy demand forecast for the period 2010-2030.

Table 71 summarizes the 2016 ZESCO energy demand forecast, the methodology used and forecasting parameters. In the following sections the two forecasts (2016 ZESCO and 2010 PSDMP) will be presented, reviewed and forecasting parameters compared to forecasts from international organisations such as the IMF and WB.

Table 71 Zambia's national electricity demand forecast

Item	Demand forecast information provided by utility – *final version in last sub-section*						
Country's demand forecast		2016	2020	2025	2030	2035	2040
	Energy demand (GWh) Base scenario	16,764	20,721	24,667	29,879	-	-
	Energy demand (GWh) High scenario	18,152	22,352	27,287	33,704	-	-
	Peak demand(MW)High Scenario	2.956	3.432	4.247	5.406	-	-
Forecast period	The forecasts cover the period 2016-2030						
Methodology used	The forecast is broken down by customer sector. New mining projects only affect the forecast during the first three years. The forecast for other sectors seems to follow an econometric approach which includes GDP. The forecast is presented under two scenarios, base and high forecast.						
Forecasting parameters	GDP growth rate is the only parameter provided. For the base case a growth rate of 5% was used, while a growth rate of 6.3% was used for the high scenario.						
Main drivers	The residential and commercial sector and existing mines drive the growth in the forecast.						

Source: Summary of information from ZESCO, 2016

A1.11.2 Review of utility's demand forecast

National demand forecast

Zambia's national electricity demand forecast is presented in Table 72 as it came from the utility. The forecast covers the periods from 2016-2030 under two scenarios, base scenario and a high scenario. The forecast is broken down by customer sectors:

- Residential & Commercial
- Industry
- Mining Existing
- Mining New

The forecast presents forecasted energy demand and an hourly average power demand. No information is presented regarding the base year of the forecast. The two scenarios show an annual energy demand growth of 4.2% and 4.5% for the base scenario and high scenario, respectively. Table 73 shows the demand forecast by the four customer sectors.

Table 72 Zambia's national demand forecast

		2016	2017	2018	2019	2020	2025	2030
Base scenario	GWh	18,764	18,314	19,117	19,944	20,721	24,667	29,879
Hourly average (MW)		1,916	2,091	2.182	2,277	2,365	2,816	3,411
High scenario	GWh	18,152	19,463	20,431	21,416	22,352	27,287	33,704
Hourly average (MW)[6]		2,072	2,222	2,332	2,445	2,552	3,115	3,848

Source: ZESCO, 2016

Existing mining projects are forecasted to grow by 5-6% annually throughout the forecasting period, excluding one year, 2018, where growth drops down to 2.3%. Both scenarios show the same growth during the forecasting period.

Demand growth from the residential and commercial sector starts at 4.5% and 6.7% per year for base, and high scenarios, respectively. The growth rates decline steadily over the forecast period and during the last year of the forecast period the growth rate is 2.2% and 3.6% for the base, and high scenario, respectively.

Growth from the industry sector remains relatively stable throughout the forecast period. The base scenario's growth rate increases from 2.6% at the start of the forecast, and increases to 3.5% near the end of the forecast. The high scenario's growth rate starts at 2.8% and increases to 4.3% at the end of the forecast.

Table 73 Zambia's national demand forecast by customer sector [GWh]

	2016	2017	2018	2019	2020	2025	2030
Base Scenario							
Residential & Commercial	5,613	5,869	6,124	6,380	6,635	7,730	8,643
Industry	1,228	1,260	1,286	1,314	1,343	1,526	1,789

[6] An hourly average demand is not useful for this task.

	2016	2017	2018	2019	2020	2025	2030
Mining existing	7,650	8,109	8,596	9,112	9,589	12,258	16,295
Mining New	2,272	3,076	3,111	3,139	3,153	3,153	3,153
High Scenario							
Residential & Commercial	6,073	6,482	6,891	7,300	7,709	9,753	11,797
Industry	1,235	1,271	1,308	1,341	1,376	1,598	1,935
Mining existing	7,650	8,109	8,596	9,112	9,589	12,258	16,295
Mining New	3,193	3,601	3,636	3,664	3,678	3,678	3,678

Source: ZESCO, 2016

The forecast does not mention whether any of the following are included:

- ❑ Transmission and distribution losses
- ❑ Exports
- ❑ Suppressed demand
- ❑ Demand side measures

Forecast from the 2010 PSDMP

The forecast provided in the 2010 PSDMP is presented in Table 74 but not reviewed in any detail, because newer data are available. The electricity demand forecast was developed using three scenarios; base case, high case and low case. The high case is the most comparable to actual 2015 data and is therefore presented in Table 74. All figures include system losses.

Table 74 2010 PSDMP high case electricity demand forecast

	Total consumption (GWh)	CEC (MW) LF=0.91 Losses=3.2%	Mining (MW) LF=0.61 Losses=3.2%	Retail (MW) LF=0.55 Losses=24.4%	Total peak (MW)	Load factor
2008	9,242	521	256	1,000	1,600	0.74
2009	9,006	380	390	1,041	1,631	0.72
2010	9,932	384	531	1,084	1,801	0.73
2011	11,853	531	649	1,129	2,080	0.73
2012	12,542	531	735	1,191	2,214	0.74
2013	12,947	580	764	1,257	2,299	0.74
2014	13,784	580	800	1,326	2,438	0.74
2015	14,069	580	800	1,399	2,504	0.74
2016	14,370	580	800	1,477	2,574	0.73

	Total consumption (GWh)	CEC (MW) LF=0.91 Losses=3.2%	Mining (MW) LF=0.61 Losses=3.2%	Retail (MW) LF=0.55 Losses=24.4%	Total peak (MW)	Load factor
2017	14,687	580	800	1,558	2,647	0.73
2018	15,022	580	800	1,644	2,725	0.72
2019	15,376	580	800	1,735	2,806	0.72
2020	15,749	580	800	1,830	2,893	0.72
2021	16,142	580	800	1,931	2,984	0.71
2022	16,557	580	800	2,038	3,080	0.71
2023	16,996	580	800	2,151	3,181	0.70
2024	17,458	580	800	2,269	3,288	0.70
2025	17,946	580	800	2,394	3,401	0.70
2026	18,461	580	800	2,527	3,520	0.69
2027	19,005	580	800	2,666	3,646	0.69
2028	19,578	580	800	2,813	3,778	0.69
2029	20,184	580	800	2,969	3,918	0.68
2030	20,823	580	800	3,133	4,066	0.68
AAG	**3.76%**	**0.5%**	**5.3%**	**5.3%**	**4.3%**	**-**

Source: PSDMP, 2010

Forecasting methodology

No information is provided on the forecasting methodology for the more recent forecast from ZESCO.

For the 2010 PSDMP the electricity demand forecast was developed by combining two methods. An econometric analysis and an end-use approach for larger loads and mines. The peak demand forecast was aggregated using a coincidence factor of 0.9 for the national power system. The forecast is based on consumption disaggregated by tariff category. The econometric analysis uses macro-economic indicators such as GDP forecasts, electrification ratio and population.

The end-user approach for bigger loads is based on data for new mining projects within the CEC and ZESCO franchises.

The forecast developed three scenarios; base case, low case and high case. The ZESCO forecast most closely resembles the ‘high case’ scenario of the 2010 PSDMP.

Parameters used in the demand forecast

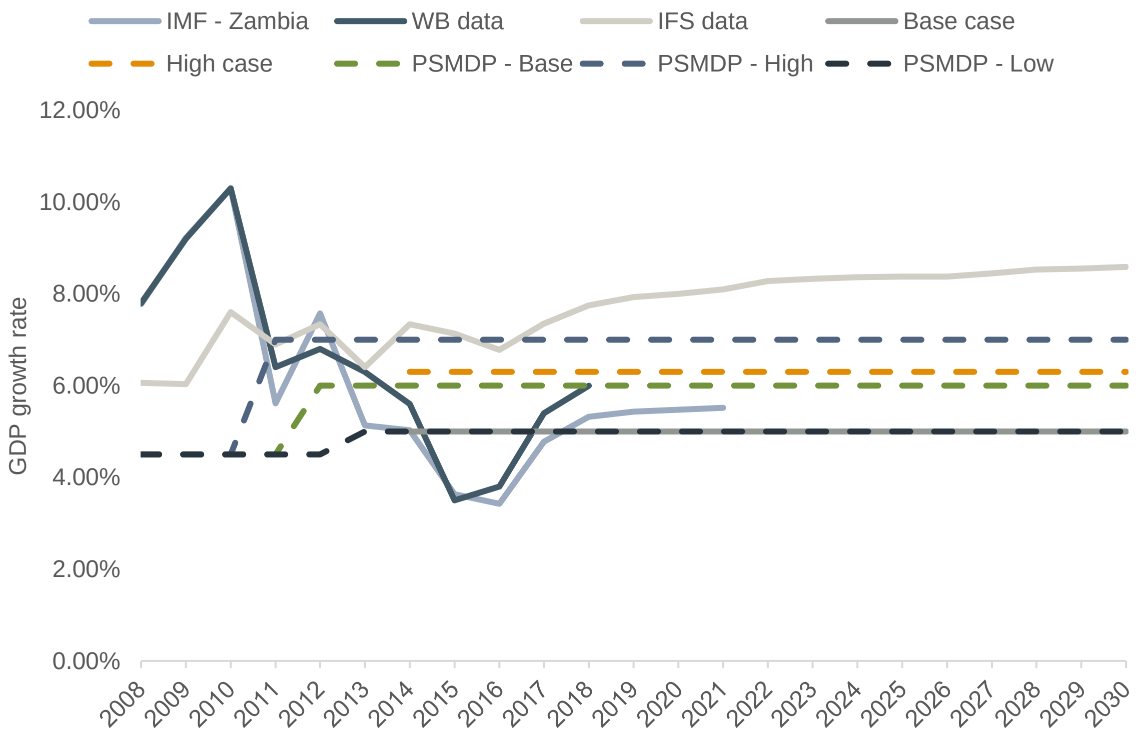
Parameters used for the more recent power demand forecast are:

- Base case GDP growth = 5%

- ❑ High case GDP growth = 6.3%

As can be seen in Figure 12 the GDP growth rates used in the forecasts (PSDMP and the recent energy demand forecast) are close to GDP forecasts of international institutions such as the IMF and WB. Historically, the 'high case' used in the PSDMP forecast shows the greatest correlation with actual GDP growth figures.

Figure 12 Comparison of GDP forecasts



Source: PDSMP, 2010. IMF, 2016. WB, 2016. ZESCO, 2016

Other macro-econometric data used for the econometric analysis are:

Population growth, 2.3% p.a. (all scenarios)

Electrification rates, 4% p.a. (base case), 6% p.a. (high case), 3.5% p.a. (low case)

Comments on the demand forecast

Comments on the more recent energy demand forecast:

- ❑ The methodology used for the forecast is not available to the Consultant and cannot be reviewed.
- ❑ The energy demand forecast was provided under two scenarios but a peak demand was not provided. An hourly average power demand was provided but is not useful for power system planning purposes. The peak demand forecast that was provided is insufficient due to the age of the data. We kindly request the system peak demand forecast.

- The energy demand forecast does not describe transmission and distribution losses, exports or parasitic load from power stations. If some losses are included in the forecast, we request information on their estimated size and portion of the demand forecast. We have assumed that the forecast does include losses and therefore entered the data under 'Energy sent out' in Table 75. In order to find 'Energy sales' we have deducted system losses provided in the 2010 PSDMP forecast.

- The forecast does not include information whether demand side measures are included. We request information if any such programs are foreseen during the forecasting period and their estimated impact on the energy demand forecast.

For Table 75 we have combined data from the 2016 ZESCO forecast with the 2010 PSDMP forecast. Technical system losses were gathered from the 2010 PSDMP forecast, along with the high case peak demand forecast. The energy demand forecast from ZESCO was combined with system losses presented in the PSDMP to find energy sales for the forecasting period.ZESCO members have assured us that an updated load forecast is currently under discussion within ZESCO, but no firm date has been set on when delivery is due.

A1.11.3 Updates to base forecast and assumptions for low forecast

The forecasts presented only reached 2030. In order to extend them to cover the entire forecasting period 2015-2040, we have extrapolated them using the average growth rate from *Energy sent out* and *Peak demand sent out* over the period 2020-2030, 3.7% and 4.6% respectively.

The 'low' demand forecast is based on an assumption of lower economic growth arising from continuation of low mineral prices and a slow-down in the pace of electrification. The annual average rate of growth in maximum demand in the base demand forecast is 4.1% per annum. In the low forecast, this is reduced to 3.4% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 75. The corresponding figures for the low forecast are given in Table 76. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 75 Zambia's updated electricity demand forecast

	Energy sales (GWh)[7]	Exports (GWh)	Losses (%)[8]	Energy sent out (GWh)	Peak demand (MW)[6]	Load factor (%)
2015	14,328	0	17%	16,764	2,857	67%
2016	14,328	0	17%	16,764	2,956	65%
2017	15,653	0	17%	18,314	3,063	68%
2018	16,339	0	17%	19,117	3,177	69%
2019	17,046	0	17%	19,944	3,300	69%
2020	17,710	0	17%	20,721	3,432	69%
2021	18,107	0	17%	21,185	3,573	68%
2022	18,821	0	17%	22,021	3,724	68%
2023	19,568	0	17%	22,894	3,886	67%
2024	20,269	0	17%	23,715	4,060	67%
2025	21,083	0	17%	24,667	4,247	66%
2026	21,837	0	17%	25,549	4,447	66%
2027	22,694	0	17%	26,552	4,662	65%
2028	23,595	0	17%	27,607	4,893	64%
2029	24,542	0	17%	28,715	5,140	64%
2030	25,538	0	17%	29,879	5,406	63%
2031	26,490	0	17%	30,993	5,616	63%
2032	27,478	0	17%	32,149	5,825	63%
2033	28,502	0	17%	33,347	6,043	63%
2034	29,565	0	17%	34,591	6,268	63%
2035	30,667	0	17%	35,880	6,501	63%
2036	31,810	0	17%	37,218	6,744	63%
2037	32,996	0	17%	38,605	6,995	63%
2038	34,226	0	17%	40,045	7,256	63%
2039	35,502	0	17%	41,538	7,527	63%
2040	36,826	0	17%	43,086	7,807	63%
AAG	**3.8%**	**-**	**-**	**3.8%**	**4.1%**	

Source: ZESCO, 2016

[7] Energy sales were gathered from applying technical system losses from PSDMP forecast to the more recent energy demand forecast provided by ZESCO.

[8] Data from the PSDMP forecast from 2010 and needs updating.

Table 76 Zambia's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*16,764*	*2,857*	*11,363*	*2,027*
2016	*16,764*	*2,956*	*11,643*	*2,053*
2017	18,314	3,063	12,645	2,115
2018	19,117	3,177	13,121	2,181
2019	19,944	3,300	13,604	2,251
2020	20,721	3,432	14,043	2,326
2021	21,185	3,573	14,263	2,406
2022	22,021	3,724	14,725	2,490
2023	22,894	3,886	15,203	2,581
2024	23,715	4,060	15,636	2,677
2025	24,667	4,247	16,144	2,780
2026	25,549	4,447	16,596	2,889
2027	26,552	4,662	17,115	3,005
2028	27,607	4,893	17,655	3,129
2029	28,715	5,140	18,216	3,261
2030	29,879	5,406	19,002	3,401
2031	30,993	5,616	19,617	3,511
2032	32,149	5,825	20,226	3,621
2033	33,347	6,043	20,855	3,733
2034	34,591	6,268	21,502	3,849
2035	35,880	6,501	22,170	3,969
2036	37,218	6,744	22,859	4,092
2037	38,605	6,995	23,569	4,219
2038	40,045	7,256	24,302	4,350
2039	41,538	7,527	25,057	4,485
2040	43,086	7,807	25,835	4,625
AAG	3.8%	4.1%	3.3%	3.4%

Source: ZESCO, 2016

A1.12 Zimbabwe

A1.12.1 Load forecast information supplied by the utility

Zimbabwe's national energy demand forecast was submitted in the document 'SAPP POOL PLAN DATA all in one file.docx' which included peak load and energy demand for the entire forecasting period. Table 77 offers a summary of the national electricity demand forecast while the later sections review the methodology used and underlying parameters. Section A1.12.3 presents Zimbabwe's national electricity demand forecast as we propose it to be presented for the SAPP Pool Plan.

Table 77 Zimbabwe's national electricity demand forecast

Item	**Demand forecast information provided by utility** – ***final version in last sub-section***						
Country's demand forecast		2015	2020	2025	2030	2035	2040
	Power (MW)	1,785	2,247	3,077	3,757	4,495	5,348
	Energy (GWh)	7,964	9,676	12,153	14,616	17,253	20,428
Forecast period	The forecast covers the period 2015-2040						
Methodology used	A bottom up end user approach and conducted separately for key economic sectors. Two models were used, the MAED model and the ZILF model. The energy demand forecasts are then aggregated to form the national electricity demand forecast. The networks' technical losses are added on top of the energy demand forecast. The peak demand forecast is created by assuming a load factor and calculating from the energy demand.						
Forecasting parameters	population growth rate, the average electrification rate and the average consumption per urban and rural household for domestic sector. For the industrial sector, GDP growth and energy intensity.						
Main drivers	The main external drivers for residential consumption is population growth while GDP growth drives industrial and commercial consumption						

Source: Summary of information from ZESA

A1.12.2 Review of utility's demand forecast

National demand forecast

The electricity demand forecast was developed in 2016 by ZESA and it covers the period 2015-2041. The base year of the demand forecast is 2015. The electricity demand forecast is composed of one scenario. The annual average energy demand forecast growth rate is 4.3% and the annual average peak demand forecast growth rate is 3.7%. The assumed load factor declines over the years from 63% in 2016 to 52% in 2041. Table 78 below depicts the energy and the power demand forecast in Zimbabwe.

Table 78 Zimbabwe's national electricity demand forecast

	Peak demand forecast (MW)	Energy demand forecast (GWh)	Load factor (%)	Peak demand growth rate (%)	Energy demand growth rate (%)
2015	1,785	7,964	61%		
2016	1,841	8,521	63%	3.1%	7.0%
2017	1,927	8,699	62%	4.7%	2.1%
2018	2,033	9,064	61%	5.5%	4.2%
2019	2,130	9,301	60%	4.8%	2.6%
2020	2,247	9,676	59%	5.5%	4.0%
2021	2,381	10,016	58%	6.0%	3.5%
2022	2,601	10,704	56%	9.2%	6.9%
2023	2,752	11,176	56%	5.8%	4.4%
2024	2,947	11,591	54%	7.1%	3.7%
2025	3,077	12,153	54%	4.4%	4.8%
2026	3,185	12,691	55%	3.5%	4.4%
2027	3,352	13,237	54%	5.2%	4.3%
2028	3,482	13,682	54%	3.9%	3.4%
2029	3,617	14,141	54%	3.9%	3.4%
2030	3,757	14,616	53%	3.9%	3.4%
2031	3,879	15,261	54%	3.2%	4.4%
2032	4,044	15,796	54%	4.3%	3.5%
2033	4,175	16,229	53%	3.2%	2.7%
2034	4,354	16,794	53%	4.3%	3.5%
2035	4,495	17,253	53%	3.2%	2.7%
2036	4,666	17,850	52%	3.8%	3.5%
2037	4,795	18,337	52%	2.8%	2.7%
2038	4,928	18,839	52%	2.8%	2.7%
2039	5,064	19,354	52%	2.8%	2.7%
2040	5,204	19,884	52%	2.8%	2.7%

Source: ZESA, 2016

Forecasting methodology

For the electricity demand forecast ZESA uses the MAED model developed by International Atomic Energy Agency (IAEA) and the ZILF model developed by Economic Consulting Associates (ECA). Both models are built in Microsoft Excel. The submitted electricity demand forecast comes out of the ZILF model.

The methodology used to produce the electricity demand forecast is a bottom up end user approach. The electricity demand forecast is conducted separately for the key economic sectors: domestic, agriculture, mining, manufacturing, and services. The individual energy demand forecasts are then aggregated to form the national electricity demand forecast. The networks' technical losses are added on top of the energy demand forecast and they are calculated as percentage of energy consumed. The peak demand forecast is estimated from the energy demand forecast with the use of an assumed load factor.

The energy demand forecast for the domestic sector is calculated as the product of the average consumption per household, the electrification rate and the number of households. The demand from the urban and the rural household is calculated separately using the above formula and it is then aggregated.

The electricity demand forecast from the productive sector is estimated from the GDP forecast of each sector and the energy intensity of each sector.

The national electricity demand forecast includes technical losses from the transmission and the distribution system and the effect of demand side measures.

The development of the electricity demand forecast with the methodology described above includes the suppressed demand.

Parameters used in the demand forecast

The key external drivers used in the domestic sector electricity demand forecast are the population growth rate, the average electrification rate and the average consumption per urban and rural household. The submitted data by ZESA include the average electrification rate and the average population growth. However, the split between urban and rural households and the average consumption per urban and rural household is missing.

Table 79 Zimbabwe average electrification rate and average population growth rate (%)

Parameter	2016 - 2018	2019-2023	2024 - 2041
Average Population Growth rate (%)	2.0	2.0	2.0
Average Electrification Rate (%)	46	54	71

Source: ZESA, 2016

The key external drivers for the productive sectors electricity demand forecast are the GDP growth rate and the energy intensities per sector. The assumed energy intensities, the GDP growth rates and the GDP contribution of each sector to the total GDP used in the electricity demand forecast are depicted in Table 80 below. The 2015 GDP used to develop the electricity demand forecast and the GDP forecast for the key productive sectors are missing.

Table 80 Zimbabwe energy intensities and GDP growth rates

Parameter	Economic Sector	2016 - 2018	2019-2023	2024 - 2041
Energy intensities (GWh/US$m)	Agriculture	0.31	0.32	0.36
	Mining	0.91	0.92	0.94
	Manufacturing	1.30	1.33	1.40
	Services	0.22	0.22	0.26
Average GDP Growth rate (%)	Total	2.0	4.0	3.0
GDP Contribution (%)	Agriculture	20.1	19.5	19.0
	Mining	8.6	8.5	8.5
	Manufacturing	16.8	16.9	17
	Services	54.5	55.1	55.1

Source: ZESA, 2016

The historical demand data cover a period from2008-2015. Table 81 presents the historical sent out generation and Table 82 presents he historical energy sales by customer category. Data for the historical technical losses, the suppressed demand and the maximum demand are missing.

Table 81 Zimbabwe historical sent out generation 2008-2015 (GWh)

Year	Hydro	Thermal	Purchases from IPP	Others (State eg Geothermal)	Total
2008	5706	1763	0.4	-	7469
2009	5458	1707	0.0	-	7165
2010	5799	2712	0.7	-	8511
2011	5201	3812	2.0	-	9016
2012	5387	3576	2.6	-	8966
2013	4982	3827	2.6	-	8811
2014	5403	3821	24.9	-	9249
2015	4938	4277	53.9	-	9269

Source: SAPP POOL PLAN DATA all in one file.docx

Table 82 Zimbabwe historical energy sales by customer category 2008-2015 (GWh)

Year	Residential	Commercial	Industrial	Agriculture	Public lighting	Others	Total (National)
2008	2,282	2,064	1,611	592	80	847	7,476
2009	2,609	1,538	1,404	599	93	809	7,052
2010	2,283	1,378	2,197	464	122	923	7,367
2011	2,634	1,473	2,156	511	58	1,107	7,940
2012	2,709	1,586	1,961	499	29	1,107	7,891
2013	2,878	1,631	3,289	490	48	1,654	8,288
2014	2,496	1,643	2,161	468	22	1,464	8,254
2015	2,249	1,653	1,757	448	14	1,297	7,417

Source: ZESA, 2016

Comments on the demand forecast

We have assumed that the energy demand forecast provided represents unsuppressed E*nergy sales* and do not include losses (technical or non-technical). In order to find *Energy sent out* we have added losses of 20% to the *Energy sales.*

The loss rate was found from historical data from 2015 provided in 'SAPP POOL PLAN DATA all in one file', where 'Historical Energy Sent out' in 2015 was shown to be 9,267 GWh and suppressed sales to be 7,417 GWh in the same year. The difference between the two was assumed to represent total system losses. The 'Energy demand' forecast for 2015 showed the national demand to be 7,964 GWh, leading to a suppressed demand of 547 GWh.

Table 83 Historical data

	2015
Historical energy sent out (GWh)	9,269.4
Total national energy sales (GWh) (suppressed demand)	7,417.3

Source: SAPP POOL PLAN DATA all in one file.docx

We have assumed that the loss rate from 2015 continues throughout the forecasting period as we have not received any data regarding loss reduction programmes.

The load factor is gathered from the *Peak demand sent out* and *Energy sent out*. We notice that the load factor starts out just over 60% but decreased throughout the forecasting period to 52% in 2040. We would like clarification on this declining trend and whether it is due to increased rural electrification.

A1.12.3 Updates to base forecast and assumptions for low forecast

The Zimbabwe national electricity demand forecast provided 'Energy Demand' and 'Peak Demand' for the entire forecasting period. From historical data we were able to find a system loss rate and assumed the same loss rate throughout the forecasting period. A suitable 'low' demand forecast was also provided.

The annual average rate of growth in maximum demand in the base demand forecast given below is 4.4% per annum. In the low forecast, this is reduced to 3.5% per annum, but as this is still above the population growth rate, there is still some improvement over the planning horizon in energy consumption per capita.

The energy and peak demand on a sent out basis, together with the implied load factor, are shown for the base forecast in Table 84. The corresponding figures for the low forecast are given in Table 85. For ease of comparison, the base forecast sent out demand and energy are also included in this table.

Table 84 Zimbabwe's updated electricity demand forecast

	Energy sales (GWh)	Exports (GWh)	Losses (%)	Energy sent out (GWh)	Peak demand sent out (MW)	Load factor (%)
2015	7,964	0	20%	9,557	1,785	61%
2016	8,521	0	19%	10,140	1,841	63%
2017	8,699	0	18%	10,265	1,927	59%
2018	9,064	0	15%	10,424	2,033	57%
2019	9,301	0	12%	10,417	2,130	56%
2020	9,676	0	12%	10,837	2,247	55%
2021	10,016	0	12%	11,218	2,381	54%
2022	10,704	0	12%	11,988	2,601	53%
2023	11,176	0	12%	12,517	2,752	52%
2024	11,591	0	12%	12,982	2,947	50%
2025	12,153	0	12%	13,611	3,077	50%
2026	12,691	0	12%	14,214	3,185	51%
2027	13,237	0	12%	14,825	3,352	50%
2028	13,682	0	12%	15,324	3,482	50%
2029	14,141	0	12%	15,838	3,617	50%
2030	14,616	0	12%	16,370	3,757	50%
2031	15,261	0	12%	17,092	3,879	50%
2032	15,796	0	12%	17,692	4,044	50%
2033	16,229	0	12%	18,176	4,175	50%
2034	16,794	0	12%	18,809	4,354	49%
2035	17,253	0	12%	19,323	4,495	49%
2036	17,850	0	12%	19,992	4,666	49%
2037	18,337	0	12%	20,537	4,795	49%
2038	18,839	0	12%	21,100	4,928	49%
2039	19,354	0	12%	21,676	5,064	49%
2040	19,884	0	12%	22,270	5,204	49%
AAG	**3.7%**	-	-	3.4%	**4.4%**	-

Source: SAPP POOL PLAN DATA all in one file.docx

Table 85 Zimbabwe's 'low' demand forecast

	Energy sent out – Base (GWh)	Peak demand sent out - Base (MW)	Energy sent out - Low (GWh)	Peak demand sent out – Low (MW)
2015	*9,557*	*1,785*	*7,763*	*1,450*
2016	*10,140*	*1,841*	*8,185*	*1,486*
2017	10,265	1,927	8,171	1,574
2018	10,424	2,033	8,213	1,641
2019	10,417	2,130	8,172	1,671
2020	10,837	2,247	8,413	1,744
2021	11,218	2,381	8,611	1,828
2022	11,988	2,601	9,046	1,963
2023	12,517	2,752	9,342	2,054
2024	12,982	2,947	9,871	2,170
2025	13,611	3,077	10,220	2,247
2026	14,214	3,185	10,507	2,310
2027	14,825	3,352	10,947	2,407
2028	15,324	3,482	11,287	2,482
2029	15,838	3,617	11,637	2,558
2030	16,370	3,757	11,997	2,638
2031	17,092	3,879	12,309	2,706
2032	17,692	4,044	12,728	2,798
2033	18,176	4,175	13,058	2,871
2034	18,809	4,354	13,506	2,969
2035	19,323	4,495	13,855	3,046
2036	19,992	4,666	14,277	3,139
2037	20,537	4,795	14,593	3,208
2038	21,100	4,928	14,917	3,280
2039	21,676	5,064	15,246	3,352
2040	22,270	5,204	15,583	3,426
AAG	3.4%	4.4%	2.8%	3.5%

Source: SAPP POOL PLAN DATA all in one file.docx

A2 Demand Forecast Summary Tables

A2.1 Maximum sent out demand (MW)

Table 86 SAPP sent out peak demand (MW), low load forecast

Year	SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	**45,794**	1,504	641	1,512	186	341	1,921	643	35,656	233	1,097	2,115	1,574
2018	**46,867**	1,577	683	1,589	182	359	2,002	654	36,388	236	1,173	2,181	1,641
2019	**47,953**	1,660	712	1,663	182	377	2,102	667	37,152	241	1,249	2,251	1,671
2020	**49,075**	1,735	744	1,725	185	394	2,187	681	37,944	246	1,322	2,326	1,744
2021	**50,221**	1,813	775	1,796	185	408	2,267	698	38,759	252	1,385	2,406	1,828
2022	**51,479**	1,884	834	1,859	186	421	2,379	716	39,593	259	1,450	2,490	1,963
2023	**52,678**	1,955	862	1,924	191	436	2,483	734	40,441	266	1,517	2,581	2,054
2024	**53,899**	2,029	891	2,021	190	450	2,541	753	41,297	273	1,588	2,677	2,170
2025	**55,021**	2,099	916	2,092	187	464	2,602	735	42,156	280	1,664	2,780	2,247
2026	**56,043**	2,168	943	2,172	190	479	2,520	755	43,013	286	1,737	2,889	2,310
2027	**57,264**	2,249	989	2,249	196	494	2,590	775	43,863	291	1,812	3,005	2,407
2028	**58,461**	2,333	1,030	2,339	195	510	2,662	797	44,702	297	1,888	3,129	2,482
2029	**59,632**	2,421	1,044	2,422	204	526	2,735	819	45,523	302	1,969	3,261	2,558
2030	**60,806**	2,514	1,071	2,510	205	542	2,810	841	46,323	306	2,054	3,401	2,638
2031	**61,891**	2,593	1,095	2,603	205	563	2,868	864	47,098	310	2,143	3,511	2,706
2032	**62,972**	2,674	1,119	2,700	205	583	2,928	887	47,843	312	2,233	3,621	2,798
2033	**64,015**	2,758	1,145	2,800	205	605	2,989	911	48,554	315	2,328	3,733	2,871
2034	**65,054**	2,845	1,168	2,904	207	626	3,053	936	49,229	316	2,426	3,849	2,969
2035	**66,039**	2,934	1,184	3,011	207	648	3,118	961	49,863	318	2,529	3,969	3,046
2036	**67,006**	3,027	1,198	3,123	211	670	3,186	987	50,455	321	2,627	4,092	3,139
2037	**67,929**	3,122	1,222	3,239	215	692	3,256	1,014	51,002	323	2,729	4,219	3,208
2038	**68,823**	3,220	1,246	3,359	220	715	3,328	1,042	51,502	326	2,835	4,350	3,280
2039	**69,681**	3,322	1,268	3,484	224	739	3,402	1,070	51,951	328	2,944	4,485	3,352
2040	**70,626**	3,427	1,291	3,613	229	763	3,479	1,099	52,350	331	3,058	4,625	3,426
AAG	**1.8%**	3.4%	3.1%	3.8%	2.1%	3.4%	2.7%	2.5%	1.9%	1.6%	4.9%	3.4%	3.5%

Table 87 SAPP sent out peak demand (MW), base load forecast

Year	SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	321,431	9,507	4,203	10,641	706	2,501	13,755	4,549	236,740	1,240	9,010	18,314	10,265
2018	335,344	10,661	4,479	10,592	740	2,944	14,327	4,780	245,677	1,283	10,320	19,117	10,424
2019	350,682	11,768	4,669	10,910	774	3,459	15,047	4,930	255,599	1,355	11,810	19,944	10,417
2020	365,016	12,994	5,406	11,445	819	3,994	15,775	5,100	263,050	1,444	13,430	20,721	10,837
2021	378,981	14,152	5,609	12,057	864	4,426	16,365	5,288	271,388	1,538	14,890	21,185	11,218
2022	393,769	15,385	5,996	12,609	914	4,897	17,199	5,443	279,195	1,632	16,490	22,021	11,988
2023	407,843	16,718	6,180	13,174	962	5,412	17,969	5,606	286,417	1,724	18,270	22,894	12,517
2024	422,747	18,051	6,370	14,046	1,015	5,973	18,409	5,793	294,359	1,803	20,230	23,715	12,982
2025	439,102	19,427	6,930	14,684	1,069	6,586	18,866	5,991	302,968	1,863	22,440	24,667	13,611
2026	455,123	21,089	7,107	15,414	1,124	7,253	18,397	6,197	312,189	1,910	24,680	25,549	14,214
2027	473,394	22,906	7,408	16,121	1,181	7,981	18,930	6,425	321,972	1,952	27,140	26,552	14,825
2028	489,812	24,895	7,519	16,960	1,238	8,774	19,479	6,655	329,541	1,990	29,830	27,607	15,324
2029	506,578	27,073	7,632	17,746	1,297	9,637	20,043	6,895	336,898	2,024	32,780	28,715	15,838
2030	523,460	29,029	7,790	18,582	1,357	10,627	20,623	7,147	343,999	2,054	36,000	29,879	16,370
2031	540,968	31,128	7,985	19,765	1,420	11,675	21,073	7,405	350,810	2,082	39,540	30,993	17,092
2032	558,404	33,379	8,185	20,718	1,486	12,811	21,537	7,636	357,297	2,104	43,410	32,149	17,692
2033	576,112	35,794	8,344	21,717	1,556	14,044	22,018	7,918	363,431	2,126	47,640	33,347	18,176
2034	594,595	38,385	8,410	23,094	1,628	15,380	22,516	8,181	369,187	2,144	52,270	34,591	18,809
2035	613,193	41,164	8,518	24,208	1,703	16,829	23,031	8,490	374,544	2,162	57,340	35,880	19,323
2036	632,465	44,146	8,696	25,738	1,776	18,400	23,563	8,787	379,484	2,184	62,480	37,218	19,992
2037	651,764	47,345	8,874	26,979	1,851	20,102	24,115	9,095	383,993	2,207	68,060	38,605	20,537
2038	672,030	50,778	9,035	28,679	1,929	21,947	24,685	9,414	388,059	2,230	74,130	40,045	21,100
2039	692,559	54,461	9,203	30,062	2,011	23,945	25,275	9,744	391,672	2,253	80,720	41,538	21,676
2040	714,586	58,413	9,377	31,511	2,096	26,105	25,885	10,085	395,600	2,276	87,880	43,086	22,270
AAG	3.42%	7.7%	3.5%	4.5%	4.8%	11.4%	2.9%	3.9%	2.5%	2.8%	11.1%	3.8%	3.4%

A2.2 Sent out energy (GWh)

Table 88 SAPP sent out energy (GWh), low load forecast

Year	SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	**306,094**	8,565	4,203	9,931	793	1,899	13,213	4,435	234,258	1,161	6,819	12,645	8,171
2018	**313,147**	8,978	4,479	9,742	804	2,000	13,853	4,503	239,070	1,177	7,206	13,121	8,213
2019	**320,821**	9,452	4,669	9,903	822	2,101	14,547	4,587	244,091	1,231	7,643	13,604	8,172
2020	**329,035**	9,879	4,879	10,277	851	2,189	15,134	4,668	249,294	1,301	8,108	14,043	8,413
2021	**337,098**	10,325	5,082	10,699	874	2,269	15,687	4,780	254,650	1,369	8,487	14,263	8,611
2022	**346,100**	10,725	5,469	11,076	902	2,350	16,466	4,890	260,128	1,436	8,886	14,725	9,046
2023	**354,842**	11,131	5,652	11,458	937	2,437	17,180	5,004	265,695	1,499	9,303	15,203	9,342
2024	**363,746**	11,551	5,842	12,042	962	2,525	17,586	5,126	271,318	1,551	9,737	15,636	9,871
2025	**372,050**	11,951	6,006	12,462	979	2,616	18,006	4,919	276,963	1,584	10,200	16,144	10,220
2026	**379,621**	12,347	6,183	12,939	1,011	2,712	17,440	5,046	282,595	1,610	10,636	16,596	10,507
2027	**388,621**	12,806	6,485	13,395	1,053	2,808	17,923	5,176	288,182	1,630	11,099	17,115	10,947
2028	**397,373**	13,286	6,582	13,932	1,074	2,909	18,419	5,305	293,689	1,647	11,589	17,655	11,287
2029	**406,096**	13,788	6,681	14,429	1,127	3,011	18,926	5,442	299,086	1,664	12,089	18,216	11,637
2030	**414,999**	14,312	6,856	14,952	1,161	3,076	19,446	5,577	304,343	1,679	12,599	19,002	11,997
2031	**423,655**	14,762	7,027	15,734	1,195	3,184	19,847	5,722	309,432	1,692	13,134	19,617	12,309
2032	**432,074**	15,226	7,203	16,318	1,231	3,297	20,261	5,861	314,326	1,704	13,694	20,226	12,728
2033	**440,272**	15,704	7,369	16,923	1,271	3,411	20,687	6,004	319,000	1,716	14,274	20,855	13,058
2034	**448,599**	16,198	7,428	17,805	1,311	3,529	21,127	6,150	323,432	1,726	14,882	21,502	13,506
2035	**456,457**	16,708	7,529	18,466	1,351	3,651	21,581	6,300	327,603	1,737	15,507	22,170	13,855
2036	**464,502**	17,234	7,701	19,424	1,378	3,776	22,049	6,453	331,493	1,748	16,110	22,859	14,277
2037	**471,988**	17,777	7,872	20,145	1,405	3,904	22,532	6,610	335,085	1,760	16,735	23,569	14,593
2038	**479,558**	18,337	8,027	21,186	1,433	4,034	23,030	6,770	338,366	1,772	17,384	24,302	14,917
2039	**486,652**	18,915	8,188	21,972	1,462	4,170	23,543	6,935	341,321	1,784	18,060	25,057	15,246
2040	**493,539**	19,512	8,356	22,788	1,491	4,309	24,073	7,103	343,940	1,796	18,754	25,835	15,583
AAG	**2.0%**	3.4%	3.0%	3.1%	3.4%	3.7%	2.8%	2.5%	1.9%	2.0%	4.6%	3.3%	2.8%

Table 89 SAPP sent out energy (GWh), base load forecast

Year	SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	321,431	9,507	4,203	10,641	706	2,501	13,755	4,549	236,740	1,240	9,010	18,314	10,265
2018	335,344	10,661	4,479	10,592	740	2,944	14,327	4,780	245,677	1,283	10,320	19,117	10,424
2019	350,682	11,768	4,669	10,910	774	3,459	15,047	4,930	255,599	1,355	11,810	19,944	10,417
2020	365,016	12,994	5,406	11,445	819	3,994	15,775	5,100	263,050	1,444	13,430	20,721	10,837
2021	378,981	14,152	5,609	12,057	864	4,426	16,365	5,288	271,388	1,538	14,890	21,185	11,218
2022	393,769	15,385	5,996	12,609	914	4,897	17,199	5,443	279,195	1,632	16,490	22,021	11,988
2023	407,843	16,718	6,180	13,174	962	5,412	17,969	5,606	286,417	1,724	18,270	22,894	12,517
2024	422,747	18,051	6,370	14,046	1,015	5,973	18,409	5,793	294,359	1,803	20,230	23,715	12,982
2025	439,102	19,427	6,930	14,684	1,069	6,586	18,866	5,991	302,968	1,863	22,440	24,667	13,611
2026	455,123	21,089	7,107	15,414	1,124	7,253	18,397	6,197	312,189	1,910	24,680	25,549	14,214
2027	473,394	22,906	7,408	16,121	1,181	7,981	18,930	6,425	321,972	1,952	27,140	26,552	14,825
2028	489,812	24,895	7,519	16,960	1,238	8,774	19,479	6,655	329,541	1,990	29,830	27,607	15,324
2029	506,578	27,073	7,632	17,746	1,297	9,637	20,043	6,895	336,898	2,024	32,780	28,715	15,838
2030	523,460	29,029	7,790	18,582	1,357	10,627	20,623	7,147	343,999	2,054	36,000	29,879	16,370
2031	540,968	31,128	7,985	19,765	1,420	11,675	21,073	7,405	350,810	2,082	39,540	30,993	17,092
2032	558,404	33,379	8,185	20,718	1,486	12,811	21,537	7,636	357,297	2,104	43,410	32,149	17,692
2033	576,112	35,794	8,344	21,717	1,556	14,044	22,018	7,918	363,431	2,126	47,640	33,347	18,176
2034	594,595	38,385	8,410	23,094	1,628	15,380	22,516	8,181	369,187	2,144	52,270	34,591	18,809
2035	613,193	41,164	8,518	24,208	1,703	16,829	23,031	8,490	374,544	2,162	57,340	35,880	19,323
2036	632,465	44,146	8,696	25,738	1,776	18,400	23,563	8,787	379,484	2,184	62,480	37,218	19,992
2037	651,764	47,345	8,874	26,979	1,851	20,102	24,115	9,095	383,993	2,207	68,060	38,605	20,537
2038	672,030	50,778	9,035	28,679	1,929	21,947	24,685	9,414	388,059	2,230	74,130	40,045	21,100
2039	692,559	54,461	9,203	30,062	2,011	23,945	25,275	9,744	391,672	2,253	80,720	41,538	21,676
2040	714,586	58,413	9,377	31,511	2,096	26,105	25,885	10,085	395,600	2,276	87,880	43,086	22,270
AAG	3.42%	7.7%	3.5%	4.5%	4.8%	11.4%	2.9%	3.9%	2.5%	2.8%	11.1%	3.8%	3.4%

A2.3 Load factor

Table 90 SAPP load factors, low load forecast

Year	SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	**76%**	65%	75%	75%	49%	64%	79%	79%	75%	57%	71%	68%	59%
2018	**76%**	65%	75%	70%	50%	64%	79%	79%	75%	57%	70%	69%	57%
2019	**76%**	65%	75%	68%	51%	64%	79%	79%	75%	58%	70%	69%	56%
2020	**77%**	65%	75%	68%	53%	63%	79%	78%	75%	60%	70%	69%	55%
2021	**77%**	65%	75%	68%	54%	64%	79%	78%	75%	62%	70%	68%	54%
2022	**77%**	65%	75%	68%	55%	64%	79%	78%	75%	63%	70%	68%	53%
2023	**77%**	65%	75%	68%	56%	64%	79%	78%	75%	64%	70%	67%	52%
2024	**77%**	65%	75%	68%	58%	64%	79%	78%	75%	65%	70%	67%	52%
2025	**77%**	65%	75%	68%	60%	64%	79%	76%	75%	65%	70%	66%	52%
2026	**77%**	65%	75%	68%	61%	65%	79%	76%	75%	64%	70%	66%	52%
2027	**77%**	65%	75%	68%	61%	65%	79%	76%	75%	64%	70%	65%	52%
2028	**78%**	65%	73%	68%	63%	65%	79%	76%	75%	63%	70%	64%	52%
2029	**78%**	65%	73%	68%	63%	65%	79%	76%	75%	63%	70%	64%	52%
2030	**78%**	65%	73%	68%	65%	65%	79%	76%	75%	63%	70%	64%	52%
2031	**78%**	65%	73%	69%	67%	65%	79%	76%	75%	62%	70%	64%	52%
2032	**78%**	65%	73%	69%	69%	65%	79%	75%	75%	62%	70%	64%	52%
2033	**79%**	65%	73%	69%	71%	64%	79%	75%	75%	62%	70%	64%	52%
2034	**79%**	65%	73%	70%	72%	64%	79%	75%	75%	62%	70%	64%	52%
2035	**79%**	65%	73%	70%	74%	64%	79%	75%	75%	62%	70%	64%	52%
2036	**79%**	65%	73%	71%	74%	64%	79%	75%	75%	62%	70%	64%	52%
2037	**79%**	65%	74%	71%	74%	64%	79%	74%	75%	62%	70%	64%	52%
2038	**80%**	65%	74%	72%	74%	64%	79%	74%	75%	62%	70%	64%	52%
2039	**80%**	65%	74%	72%	74%	64%	79%	74%	75%	62%	70%	64%	52%
2040	**80%**	65%	74%	72%	74%	65%	79%	74%	75%	62%	70%	64%	52%

Values are adjusted for a diversity factory of 1.03, rising to 1.10 in 2040.

Table 91 SAPP load factors, base load forecast

Year	SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	**76%**	65%	75%	75%	49%	64%	81%	75%	75%	56%	71%	68%	59%
2018	**76%**	65%	75%	70%	50%	64%	80%	74%	75%	57%	70%	69%	57%
2019	**76%**	65%	75%	68%	51%	64%	80%	74%	75%	58%	70%	69%	56%
2020	**76%**	65%	75%	68%	53%	63%	80%	74%	75%	60%	70%	69%	55%
2021	**76%**	65%	75%	68%	54%	64%	79%	74%	75%	62%	70%	68%	54%
2022	**76%**	65%	75%	68%	55%	64%	79%	74%	75%	63%	70%	68%	53%
2023	**76%**	65%	75%	68%	56%	64%	79%	74%	75%	64%	70%	67%	52%
2024	**76%**	65%	75%	68%	58%	64%	78%	74%	75%	65%	70%	67%	50%
2025	**76%**	65%	75%	68%	60%	64%	78%	73%	75%	65%	70%	66%	50%
2026	**76%**	65%	75%	68%	61%	65%	79%	73%	75%	64%	70%	66%	51%
2027	**77%**	65%	75%	68%	61%	65%	79%	73%	75%	64%	70%	65%	50%
2028	**77%**	65%	73%	68%	63%	65%	79%	73%	75%	63%	70%	64%	50%
2029	**77%**	65%	73%	68%	63%	65%	79%	73%	75%	63%	70%	64%	50%
2030	**77%**	65%	73%	68%	65%	65%	78%	73%	75%	63%	70%	63%	50%
2031	**77%**	65%	74%	69%	67%	65%	78%	73%	75%	62%	70%	63%	50%
2032	**77%**	65%	74%	69%	69%	65%	78%	73%	75%	62%	70%	63%	50%
2033	**77%**	65%	74%	69%	71%	64%	78%	73%	75%	62%	70%	63%	50%
2034	**77%**	65%	73%	70%	72%	64%	78%	73%	75%	62%	70%	63%	49%
2035	**77%**	65%	73%	70%	74%	64%	78%	73%	75%	62%	70%	63%	49%
2036	**78%**	65%	74%	71%	74%	64%	77%	73%	75%	62%	70%	63%	49%
2037	**78%**	65%	74%	71%	74%	64%	77%	73%	75%	62%	70%	63%	49%
2038	**78%**	65%	74%	72%	74%	64%	77%	73%	75%	62%	70%	63%	49%
2039	**78%**	65%	74%	72%	74%	64%	77%	73%	75%	62%	70%	63%	49%
2040	**78%**	65%	75%	72%	74%	65%	77%	73%	75%	62%	70%	63%	49%

Values are adjusted for a diversity factory of 1.03, rising to 1.10 in 2040.

A2.4 Energy sent out (kWh per capita)

Table 92 SAPP Energy sent out (kWh per capita), low load forecast

Year	Av SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	**939**	321	1,793	121	363	104	447	1,726	4,164	880	120	734	500
2018	**949**	327	1,879	115	364	106	457	1,717	4,195	881	123	738	491
2019	**960**	333	1,928	113	368	108	467	1,714	4,230	911	126	743	478
2020	**973**	338	1,983	114	377	109	473	1,709	4,268	952	130	744	482
2021	**986**	342	2,034	115	383	110	478	1,716	4,308	991	132	733	482
2022	**1,006**	345	2,156	116	391	111	488	1,722	4,351	1,029	135	735	496
2023	**1,019**	347	2,197	116	403	112	496	1,729	4,394	1,063	137	736	502
2024	**1,032**	350	2,239	119	409	112	495	1,739	4,438	1,089	139	735	520
2025	**1,032**	351	2,270	119	412	113	494	1,639	4,483	1,102	142	737	528
2026	**1,040**	352	2,306	120	422	114	466	1,651	4,527	1,108	144	736	532
2027	**1,054**	355	2,388	121	435	115	467	1,664	4,570	1,112	146	737	543
2028	**1,061**	358	2,394	122	440	116	468	1,676	4,612	1,114	148	739	549
2029	**1,069**	361	2,400	123	457	116	468	1,691	4,652	1,115	150	741	555
2030	**1,079**	364	2,434	124	467	116	469	1,704	4,689	1,114	152	751	562
2031	**1,087**	365	2,466	127	476	117	467	1,720	4,725	1,113	154	753	566
2032	**1,096**	366	2,499	128	486	118	465	1,735	4,758	1,111	156	755	574
2033	**1,104**	367	2,529	130	497	118	463	1,749	4,787	1,109	159	757	578
2034	**1,109**	368	2,522	133	508	119	462	1,764	4,813	1,105	161	759	587
2035	**1,114**	369	2,530	134	519	120	460	1,780	4,836	1,102	163	761	592
2036	**1,121**	371	2,561	138	524	121	459	1,796	4,856	1,100	165	763	599
2037	**1,127**	373	2,592	139	530	122	458	1,813	4,871	1,097	167	766	602
2038	**1,133**	374	2,617	143	535	123	457	1,830	4,883	1,094	169	768	605
2039	**1,139**	376	2,644	145	541	124	457	1,848	4,891	1,092	171	771	608
2040	**1,145**	378	2,673	146	547	125	456	1,867	4,896	1,090	173	774	611
AAG	**0.8%**	0.6%	1.7%	0.3%	2.4%	0.8%	0.2%	0.7%	0.9%	1.0%	1.7%	0.4%	0.8%

Table 93 SAPP Energy sent out (kWh per capita), base load forecast

Year	Av SAPP	Angola	Botswana	DRC	Lesotho	Malawi	Mozambique	Namibia	S Africa	Swaziland	Tanzania	Zambia	Zimbabwe
2017	1,005	357	1,793	129	323	137	550	1,771	4,208	939	158	1,062	628
2018	1,033	388	1,879	125	335	156	544	1,822	4,311	961	176	1,076	624
2019	1,059	415	1,928	125	346	178	546	1,842	4,429	1,003	195	1,089	609
2020	1,108	444	2,198	127	363	199	609	1,867	4,503	1,057	216	1,097	620
2021	1,138	469	2,246	130	379	215	660	1,898	4,591	1,113	232	1,089	628
2022	1,169	495	2,364	132	397	231	651	1,917	4,669	1,169	250	1,099	658
2023	1,192	522	2,402	134	413	248	637	1,937	4,737	1,223	269	1,109	673
2024	1,216	547	2,441	138	432	266	631	1,965	4,815	1,266	289	1,116	684
2025	1,258	571	2,619	140	451	285	695	1,996	4,904	1,296	312	1,127	703
2026	1,281	602	2,651	143	469	305	671	2,027	5,001	1,316	333	1,133	719
2027	1,316	635	2,728	146	488	326	726	2,065	5,106	1,331	356	1,144	736
2028	1,339	670	2,734	149	507	349	750	2,103	5,175	1,345	380	1,155	746
2029	1,358	708	2,741	152	527	373	731	2,143	5,240	1,356	406	1,167	756
2030	1,379	738	2,765	154	546	400	714	2,184	5,300	1,363	434	1,180	767
2031	1,402	769	2,802	160	566	427	707	2,226	5,357	1,369	464	1,190	786
2032	1,423	802	2,840	163	587	457	700	2,260	5,408	1,372	495	1,200	798
2033	1,444	836	2,863	167	609	488	694	2,306	5,454	1,374	529	1,210	805
2034	1,463	872	2,856	172	631	520	688	2,347	5,494	1,373	565	1,220	818
2035	1,483	910	2,862	176	654	555	682	2,399	5,529	1,372	604	1,231	826
2036	1,506	950	2,892	183	676	591	677	2,446	5,559	1,374	640	1,242	839
2037	1,528	992	2,922	187	698	630	672	2,495	5,582	1,375	680	1,254	847
2038	1,550	1,037	2,946	193	721	671	668	2,545	5,601	1,377	721	1,266	855
2039	1,573	1,083	2,972	198	744	714	664	2,597	5,613	1,379	765	1,278	864
2040	1,597	1,132	3,000	202	768	760	660	2,651	5,631	1,381	812	1,291	873
AAG	1.8%	4.8%	2.2%	1.6%	3.8%	8.4%	1.3%	2.1%	1.4%	1.8%	8.0%	0.9%	1.4%

A3 Generation Plan Annexes

A3.1 Energy balance and planned / installed capacity by country

The tables for this annex are provided as a **separate spreadsheet**. For each country, each year from 2017 to 2040, and for both energy (GWh) and capacity (MW), the following details are given:

- Energy Balance – national generation, imports, exports, unserved energy and energy demand by country.
- Capacity totals – total national installed capacity[9], peak demand and reserve margin.

The information is presented in separate panels for existing, committed and the candidate projects which have been selected.

[9] Note that the capacities presented below are installed capacities. Available capacities used in PLEXOS simulations may differ and are not presented below.

A3.2 Capital costs of candidate projects

The following tables present the capital costs assumed for each candidate project by country.

Table 94 Capital costs of candidate projects in Angola

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Baynes (Angola)	Hydro	300	2,310
Cafula (Keve)	Hydro	400	3,885
Calengue (Catumbela)	Hydro	190	3,150
Cutato 1-3	Hydro	100	3,150
Jamba Ya Mina	Hydro	180	3,150
Jamba Ya Oma	Hydro	75	3,150
Lomaum 2	Hydro	160	3,150
Angola OCGT NG	Thermal	100	835
Quilengue (Keve)	Hydro	217	4,350
Tumulo do Cacador	Hydro	450	3,150
Zenzo I	Hydro	450	3,150

Table 95 Capital costs of candidate projects in Botswana

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Botswana Coal	Thermal	700	2,377
Botswana Coal Green field	Thermal	132	2,377

Table 96 Capital costs of candidate projects in DRC

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Busanga	Hydro	240	3,150
Gecamines Coal (500)	Thermal	500	2,377
Inga 3 BC	Hydro	4,800	4,410
Inga 3 HC	Hydro	7,942	630
Inga 4	Hydro	3,712	2,205
Sombwe	Hydro	300	3,150
Wanie Rukula	Hydro	688	3,150
Nzongo	Hydro	150	3,150

Table 97 Capital costs of candidate projects in Lesotho

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Lesotho Letseng Wind	Renewable	65	1,806
Muela 2	Hydro	110	3,150
Oxbow	Hydro	80	3,150

Table 98 Capital costs of candidate projects in Malawi

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Malawi Biomass	Biomass	20	4,263
Chasombo	Hydro	41	4,095
Chizuma	Hydro	40	4,095
Malawi Coal 300	Thermal	819	2,377
Malawi Engines	Thermal	75	1,140
Fufu	Hydro	261	3,150
Hamilton Falls	Hydro	96	3,780
Malawi HFO	Thermal	19	1,140
Kapichira Falls Phase III	Hydro	112	3,780
Kholombidzo	Hydro	219	3,150
Mpatamanga	Hydro	309	3,150
Malawi Solar	Renewable	165	1,040
Songwe	Hydro	45	6,510
Malawi Wind	Renewable	120	1,806

Table 99 Capital costs of candidate projects in Mozambique

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Moz CCGT NG	Thermal	750	1,065
Moz Engines NG	Thermal	5,000	1,140
Massingir	Hydro	54	3,150
Moz OCGT NG	Thermal	4,000	835
Moz CCGT NG	Thermal	2,625	1,065
Moz Coal	Thermal	75	2,377
Moz Engines NG	Thermal	80	1,140

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Moz ENI NG	Thermal	6,000	1,140
Moz ENRC	Thermal	300	1,140
Moz Cahora Bassa Norte	Hydro	1,245	788
Lurio	Hydro	120	3,150
Moatize	Thermal	300	2,377
Ncondezi	Thermal	300	2,377
Moz OCGT NG	Thermal	4,000	835
Moz Shell	Thermal	80	1,575
Tsate	Hydro	50	3,150
Moz CCGT NG	Thermal	2,500	1,065
Moz Engines NG	Thermal	5,000	1,140
Moz OCGT NG	Thermal	1,245	835

Table 100 Capital costs of candidate projects in Namibia

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Baynes (Namibia)	Hydro	300	2,310
Namibia CCGT NG	Thermal	1,250	1,065
Namibia Coal	Thermal	300	2,377
Kudu	Thermal	400	1,065
Namibia OCGT NG	Thermal	1,200	835

Table 101 Capital costs of candidate projects in South Africa

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
SA Generic Biomass	Biomass	500	4,263
SA CCGT NG	Thermal	1,875	1,065
SA Coal (Large)	Thermal	7,500	3,926
SA OCGT NG	Thermal	700	835
SA Generic Solar PV (Large)	Renewable	2,000	1,040
SA Generic Solar PV (Medium)	Renewable	2,000	1,040
SA Generic Wind (Large)	Renewable	3,000	1,806
SA Generic Wind (Medium)	Renewable	2,000	1,806

Table 102 Capital costs of candidate projects in Swaziland

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Ngwempisi	Hydro	120	3,150
Swaziland Biomass	Biomass	35	4,263
Lubhuku	Thermal	300	2,377

Table 103 Capital costs of candidate projects in Tanzania

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Tanzania Biomass	Biomass	85	4,263
Future CGT3	Thermal	5,640	1,065
Tanzania Geothermal	Thermal	200	4,263
Tanzania Local Coal I	Thermal	100	2,377
Tanzania Local Coal II	Thermal	300	2,377
Tanzania Local Coal III	Thermal	300	2,377
Tanzania Local Coal IV	Thermal	300	2,377
Malagaresi	Hydro	45	3,150
Masigira	Hydro	59	3,150
Mchuchuma III	Thermal	200	2,377
Mkuranga OCGT	Thermal	200	835
Mpanga	Hydro	160	3,150
Mtwara	Thermal	400	835
Ruhudji	Hydro	360	3,150
Rumakali	Hydro	173	3,150
Songwe Bipungu	Hydro	11	3,150
Songwe Manolo	Hydro	50	3,150
Songwe Sofre	Hydro	80	3,150
Steiglers Gorge I	Hydro	1,048	3,150
Steiglers Gorge II	Hydro	210	3,603
Taveta	Hydro	146	3,603
Upper Kihansi	Hydro	47	3,977

Table 104 Capital costs of candidate projects in Zambia

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
Zambia Coal	Thermal	300	2,377
Devil's Gorge North	Hydro	600	3,150
Indola HFO	Thermal	21	2,400
Kabompo Gorge	Hydro	34	3,150
Kalungwishi II	Hydro	62	3,150
Luchenene	Hydro	30	3,150
Lunsemfwa	Hydro	55	3,150
Mambilimba Falls I	Hydro	124	3,150
Mambilimba Falls II	Hydro	202	3,150
Mkushi	Hydro	65	3,150
Mupata Gorge North	Hydro	150	9,000
Mutinondo	Hydro	40	3,150

Table 105 Capital costs of candidate projects in Zimbabwe

Name	Fuel	Capacity (MW)	Investment costs per kW (US$)
CASECO Coal	Thermal	1,200	2,377
Chisumbanje	Biomass	4	2,625
Zimbabwe Coal	Thermal	2,400	2,377
Devil's Gorge South	Hydro	600	3,150
Zimbabwe NG	Thermal	50	1,575
Gokwe North	Thermal	300	2,310
Lupane CCGT	Thermal	600	2,625
Lusulu	Thermal	200	2,310
Mupata Gorge South	Hydro	600	9,000
Southern Energy	Thermal	660	2,377
Western Area Coal	Thermal	1,200	2,377
ZPC Solar CSP	Thermal	300	4,186

A3.3 Operating costs of candidate projects

The tables below present the operating costs of candidate power plants by country by year. Costs are presented for those candidate power plants that were selected in PLEXOS simulations.

Table 106 Operating costs of candidate power plants in Angola ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Baynes (Angola)	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Cafula (Keve)	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Calengue (Catumbela)	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5
Cutato 1-3	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Jamba Ya Mina	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5
Jamba Ya Oma	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Lomaum 2	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5
Quilengue (Keve)	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5
Tumulo do Cacador	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Zenzo I	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5

Table 107 Operating costs of candidate power plants in Botswana ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Botswana Coal	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.5	33.7
Botswana Coal Green field	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.7	34.0	34.2

Table 108 Operating costs of candidate power plants in DRC ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Gecamines Coal (500)	Coal	0.0	0.0	0.0	26.9	27.1	27.3	0.0	27.7	27.9	28.1	28.3	28.5	28.7	28.9	29.1	29.3	29.5	29.7	30.0	30.2	30.4	30.6	30.8	31.1
Inga 3 BC	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inga 3 HC	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Inga 4	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Sombwe	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5

Table 109 Operating costs of candidate power plants in Lesotho ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Lesotho Letseng Wind	Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.0	11.0	11.0	11.0	11.0	11.0
Muela 2	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5
Oxbow	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5

Table 110 Operating costs of candidate power plants in Malawi ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Chasombo	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5
Chizuma	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5
Malawi Coal 300	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.6	37.9	38.2
Malawi Engines	Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	218.5	225.7	228.0	230.5	0.0	235.4	237.9	240.4	243.0	245.5	248.2	250.8
Fufu	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5
Kapichira Falls Phase III	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Kholombidzo	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5
Mpatamanga	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Malawi Solar	Solar PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Malawi Wind	Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 111 Operating costs of candidate power plants in Mozambique ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Moz CCGT NG	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.2	28.7	29.1	29.6	30.1	30.5	31.0	31.5	32.0	32.6	33.1	33.6	34.2	34.7
Moz CCGT NG	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.2	28.7	29.1	29.6	30.1	30.5	31.0	31.5	32.0	32.6	33.1	33.6	34.2	34.7
Moz ENRC	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.5	5.5
Lurio	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Moatize	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.5	5.5
Tsate	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Moz CCGT NG	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.2	28.7	29.1	29.6	30.1	30.5	31.0	31.5	32.0	32.6	33.1	33.6	34.2	34.7
Moz CCGT NG	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.2	28.7	29.1	29.6	30.1	30.5	31.0	31.5	32.0	32.6	33.1	33.6	34.2	34.7

Table 112 Operating costs of candidate power plants in Namibia ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Baynes (Namibia)	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Kudu	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.8	33.4	33.9	34.5

Table 113 Operating costs of candidate power plants in Swaziland ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Ngwempisi	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Lubhuku	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	35.2

Table 114 Operating costs of candidate power plants in Tanzania ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Future CGT3	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.8	27.2	27.7	28.1	28.6	29.0	29.5	30.0	30.5	31.0	31.5	32.0	32.5	33.0	33.6
Tanzania Geothermal	Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	8.0	8.0	8.0	8.0	8.0
Tanzania Local Coal I	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.2	31.4
Tanzania Local Coal II	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.2	31.4
Tanzania Local Coal III	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.2	31.4
Tanzania Local Coal IV	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.2	31.4
Malagaresi	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Mchuchuma III	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.2	31.4
Mkuranga OCGT	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	42.1	42.8	43.5	44.2	45.0	45.7
Mpanga	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5
Mtwara	Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	45.7
Ruhudji	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Songwe Sofre	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Steiglers Gorge I	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5
Taveta	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5

Table 115 Operating costs of candidate power plants in Zambia ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Zambia Coal	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.2	31.4
Devil's Gorge North	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Indola HFO	Heavy fuel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Kabompo Gorge	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Kalungwishi II	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Luchenene	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Lunsemfwa	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Mambilimba Falls I	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Mambilimba Falls II	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Mkushi	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Mutinondo	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5

Table 116 Operating costs of candidate power plants in Zimbabwe ($/MWh)

Name	Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Devil's Gorge South	Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5

A4 GIS and RIAM Analysis

The various generation projects and interconnector and transmission lines of national importance which have been modelled within PLEXOShave also been assessed utilizing the GIS and RIAM. The analysis for both transmission and generation is presented following utilizing a map based approach.

A4.1 Transmission Line Route Corridors

The alignment of the transmission corridors was carried out using the national parks and RIAM sensitivity maps to provide an alignment which seeks to mitigate against impacts (or enhance benefits) in the following areas (range values in brackets):

- Physical / Chemical
  - Water Bodies (-2)
  - Erosion Potential (-2)

- Biological / Ecological
  - Water Bodies (-4)
  - High Vegetation (-3)
  - Protected Areas (-5)
  - Biodiversity Hotspots (-5)

- Socio-Economic / Cultural
  - Settlements (-2)
  - High Population Density (-1)
  - Historical /Cultural (-4)
  - Tourist Sites (-4)
  - Cultivated Land (-2)
  - Developments (3)
  - Tribal/Customary Land (-4)

- National Park

For each interconnector or transmission corridor a map is presented illustrating the alignment in combination with the Combined RIAM Sensitivity Map as well as the location of the National Parks. A table is also provided which illustrated a summary of all the spatial data variables integrated into the 2.5 km by 2.5km grid cells.

For planning purposes, National Parks have been defined as "no-go" areas for major transmission line corridors. As the GIS database is expanded additional parameters may be added as no-go criteria if deemed appropriate.

Figure 2 and Table 1 give the overview of the transmission lines assessed. Thereafter the maps illustrate individual lines.

Figure 13 Map of main regional transmission corridors

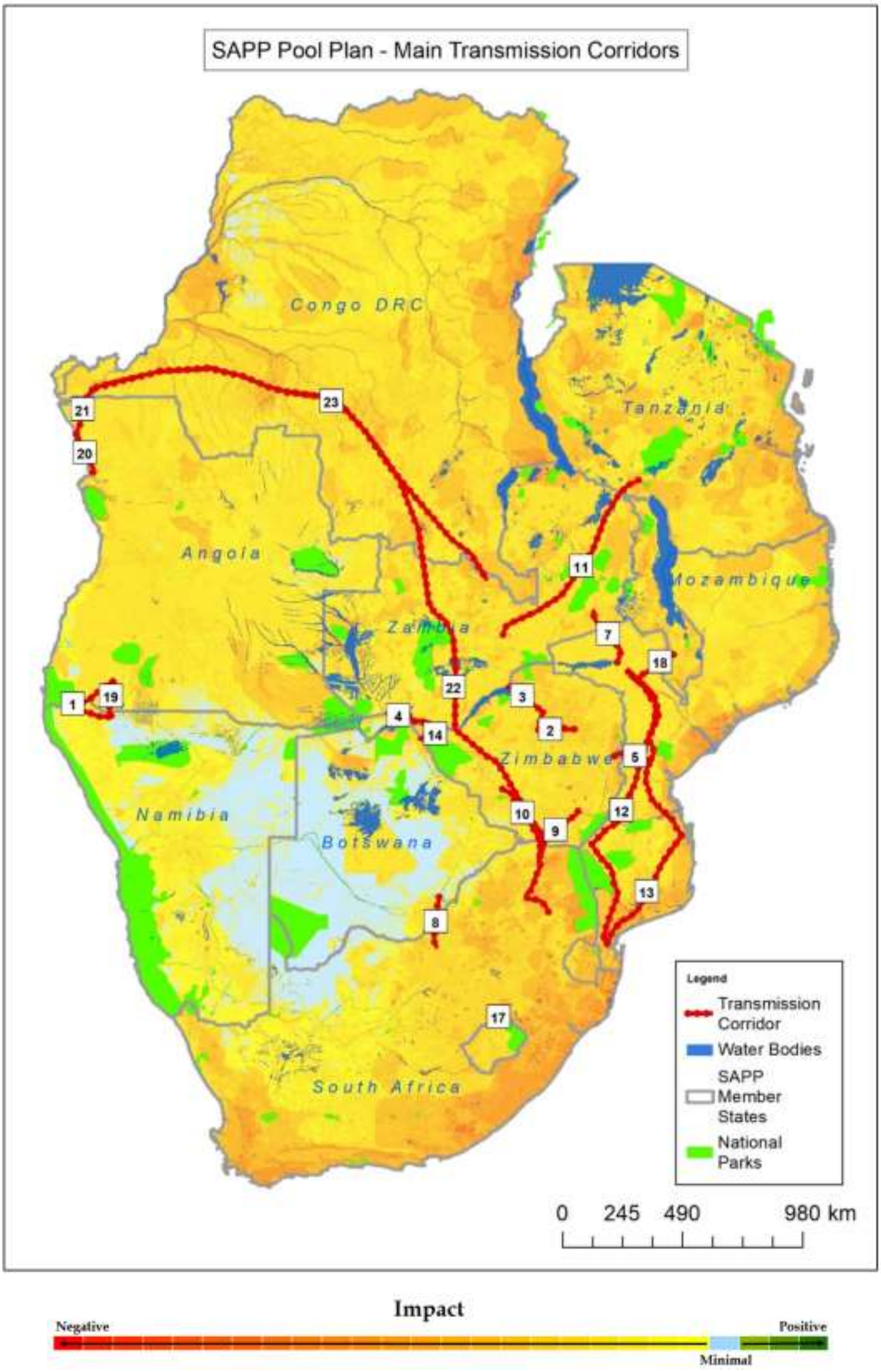


Table 117 List of main regional transmission corridors

No	PLEXOS Name
1	P_Angola-Namibia I (400kV HVAC) and P_Angola-Namibia Ib (400kV HVAC)
2	P_Zambia-Zimbabwe IV (400kV HVAC)
3	P_Zambia-Zimbabwe III (400kV HVAC)
4	P_Zambia-Namibia I (400kV HVDC)
5	P_MozC-Zimbabwe I (400kV HVAC)
7	P_MozN-Zambia (330kV HVAC)
8	P_Botswana -South Africa II (400 kV HVAC)
9	E_South Africa-Zimbabwe I (400kV HVAC)
10	P_Zimbabwe-South Africa I (400kV HVAC)
11	P_Zambia-Tanzania IIa (500kV HVDC) and P_Zambia-Tanzania IIb (500kV HVDC)
12	P_MozN-MozS Ia (500kV HVDC) and P_MozN-MozS Ib (500kV HVDC)
13	P_MozN-MozC I (400kV HVAC) and P_MozC-MozS I (400kV HVAC)
14	C_Zambia-Zimbabwe I (330kV HVAC)
16	P_Botswana-Zimbabwe I (330kV HVAC)
17	P_Lesotho-South Africa III (132kV HVAC)
18	P_Malawi-MozN I (400kV HVAC) and P_Malawi-MozN II (400kV HVAC) and P_Malawi-MozN III (400kV HVAC)
19	P_Angola-Namibia I (400kV HVAC)
20	Part of P_DRC-Angola III (400kV HVAC)
21	P_DRC-Angola I (400kV HVAC) andP_DRC-Angola II (400kV HVAC) and P_DRC-Angola III (400kV HVAC)
22	P_DRC-South Africa I (600kV HVDC) and P_DRC-South Africa II (600kV HVDC)
23	P_DRC-Zambia I (500kV HVDC) and P_DRC-Zambia II (500kV HVDC)

Table 118 P_Angola-Namibia I (400kV HVAC) and Ib (400kV HVAC)

Component A	
Component B	2022, Baynes in 2029
Component C	2022, Baynes in 2027
Voltage (kV)	400 AC
Capacity (MW)	250 MW initially, 350 MW once Baynes is added
Start	Cahama
End	Kunene
Other substations	Baynes

Figure 14 Map of P_Angola-Namibia I and Ib

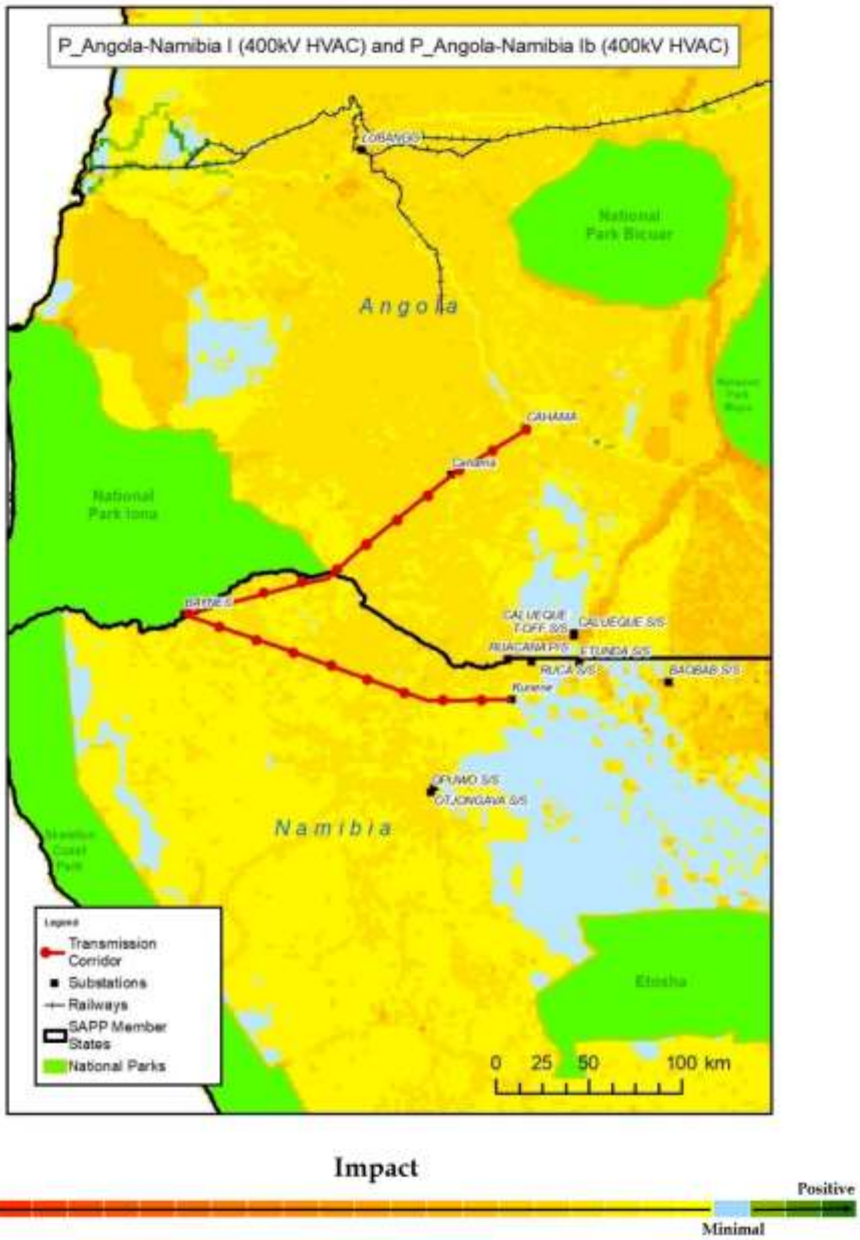


Table 119 GIS Analysis of P_Angola-Namibia I and Ib

Number of GRIDS: 500

Sinks

Mines	6
Big Mines (>5 ha)	1
Small Mines (<5 ha)	4
Industrial Areas	0
Commercial Areas	0
Airports	2
Utilities	0
Harbours	0
Reservoirs	2

Sources

Power Lines (exist)	11
Power Lines (plan)	14
Power Plants (exist)	1
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	23
Wetland	0
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	147
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	4
Towns	1
Night Lights	0
Village/Rural Settlmnt	4
Densely Populated	0
Population Estimates	10,131
Commercial Cultivation	0
Development Corridors	5
Development Hubs	0
Potential Development	0

Resources

Coal Resources	0
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	20
National Parks	20
Cultivation	0
Historic Areas	0
Tourist Attractions	2
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	112
Tropical Storms	0
Lightning	0
Wildfires	0
Erosion	497

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	161
Floodplain	16

Constraints

Paved Roads	30
Unpaved Roads	161
Major/Main Roads	7
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	333
Low Vegetation	497
Grasslands	354
Bare Earth	302

Table 120 P_Zambia-Zimbabwe IV (400kV HVAC)	
Component A	
Component B	
Component C	2033
Voltage (kV)	400 AC
Capacity (MW)	500
Start	Alaska
End	DEMA
Other substations	Chakari, Selous

Figure 15 Map of P_Zambia-Zimbabwe IV

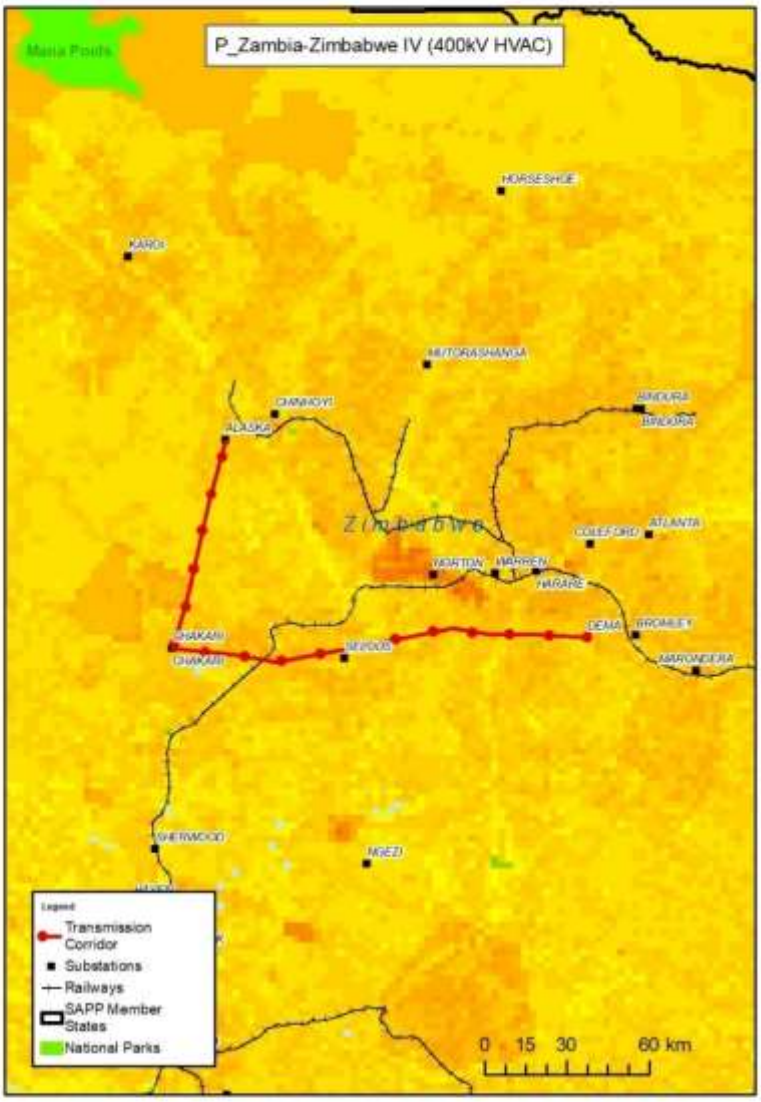


Table 121 GIS Analysis of P_Zambia-Zimbabwe IV

Number of GRIDS: 291

Sinks

Mines	22
Big Mines (>5 ha)	12
Small Mines (<5 ha)	6
Industrial Areas	1
Commercial Areas	1
Airports	1
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	19
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	3
Substations (plan)	0

Limitations

Water	86
Wetland	0
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	185
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	51
Towns	1
Night Lights	5
Village/Rural Settlmnt	92
Densely Populated	58
Population Estimates	104,710
Commercial Cultivation	177
Development Corridors	23
Development Hubs	0
Potential Development	0

Resources

Coal Resources	0
PV Resources	130
CSP Resources	130
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	7
National Parks	0
Cultivation	177
Historic Areas	3
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	19
Wildfires	0
Erosion	284

Sinks

Load Centres	0

Commodities

Gold	3
Copper	66
Aluminium	0
Diamonds	0
Uranium	0
Chromium	13
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	4
Floodplain	100

Constraints

Paved Roads	64
Unpaved Roads	279
Major/Main Roads	46
Railway Lines	5
Railway Stations	0

Background Info

Tall Bushes / Trees	289
Low Vegetation	291
Grasslands	291
Bare Earth	71

Table 122 P_Zambia-Zimbabwe III (400kV HVAC)	
Component A	
Component B	
Component C	2033
Voltage (kV)	400 AC
Capacity (MW)	300
Start	Kariba North
End	Alaska
Other substations	

Figure 16 Map of P_Zambia-Zimbabwe III

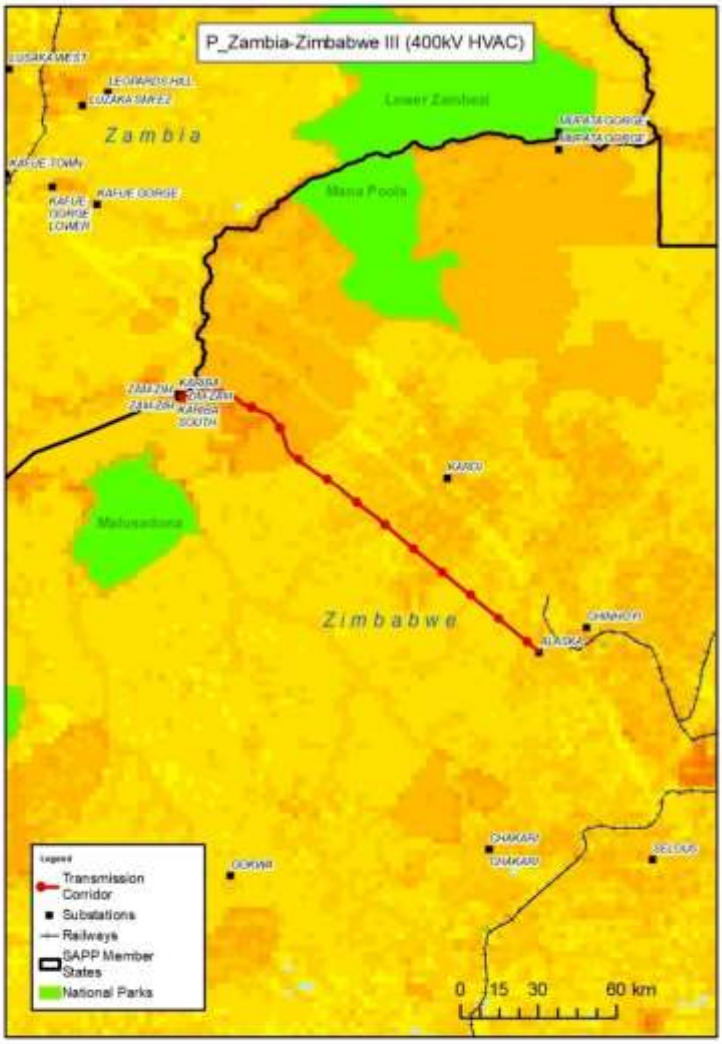


Table 123 GIS Analysis of P_Zambia-Zimbabwe III

Number of GRIDS: 237

Sinks

Mines	6
Big Mines (>5 ha)	3
Small Mines (<5 ha)	3
Industrial Areas	0
Commercial Areas	0
Airports	1
Utilities	0
Harbours	3
Reservoirs	0

Sources

Power Lines (exist)	69
Power Lines (plan)	0
Power Plants (exist)	1
Power Plants (plan)	0
Substations (exist)	2
Substations (plan)	0

Limitations

Water	104
Wetland	11
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	149
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	24
Towns	1
Night Lights	3
Village/Rural Settlmnt	55
Densely Populated	4
Population Estimates	26,488
Commercial Cultivation	21
Development Corridors	0
Development Hubs	0
Potential Development	0

Resources

Coal Resources	18
PV Resources	42
CSP Resources	0
Wind Resources	32
Undiscovered Oil / Gas	0

Land Use

Protected Areas	73
National Parks	0
Cultivation	21
Historic Areas	0
Tourist Attractions	1
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	40
Tropical Storms	0
Lightning	46
Wildfires	0
Erosion	236

Sinks

Load Centres	0

Commodities

Gold	0
Copper	16
Aluminium	0
Diamonds	2
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	22
Floodplain	38

Constraints

Paved Roads	29
Unpaved Roads	192
Major/Main Roads	30
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	221
Low Vegetation	236
Grasslands	236
Bare Earth	48

Table 124 P_Zambia-Namibia I (400kV HVDC)	
Component A	
Component B	2035
Component C	2039
Voltage (kV)	400 AC
Capacity (MW)	150 MW increment on Zambia - Namibia link
Start	Livingstone
End	Zambesi
Other substations	Sesheke

Figure 17 Map of P_Zambia-Namibia I

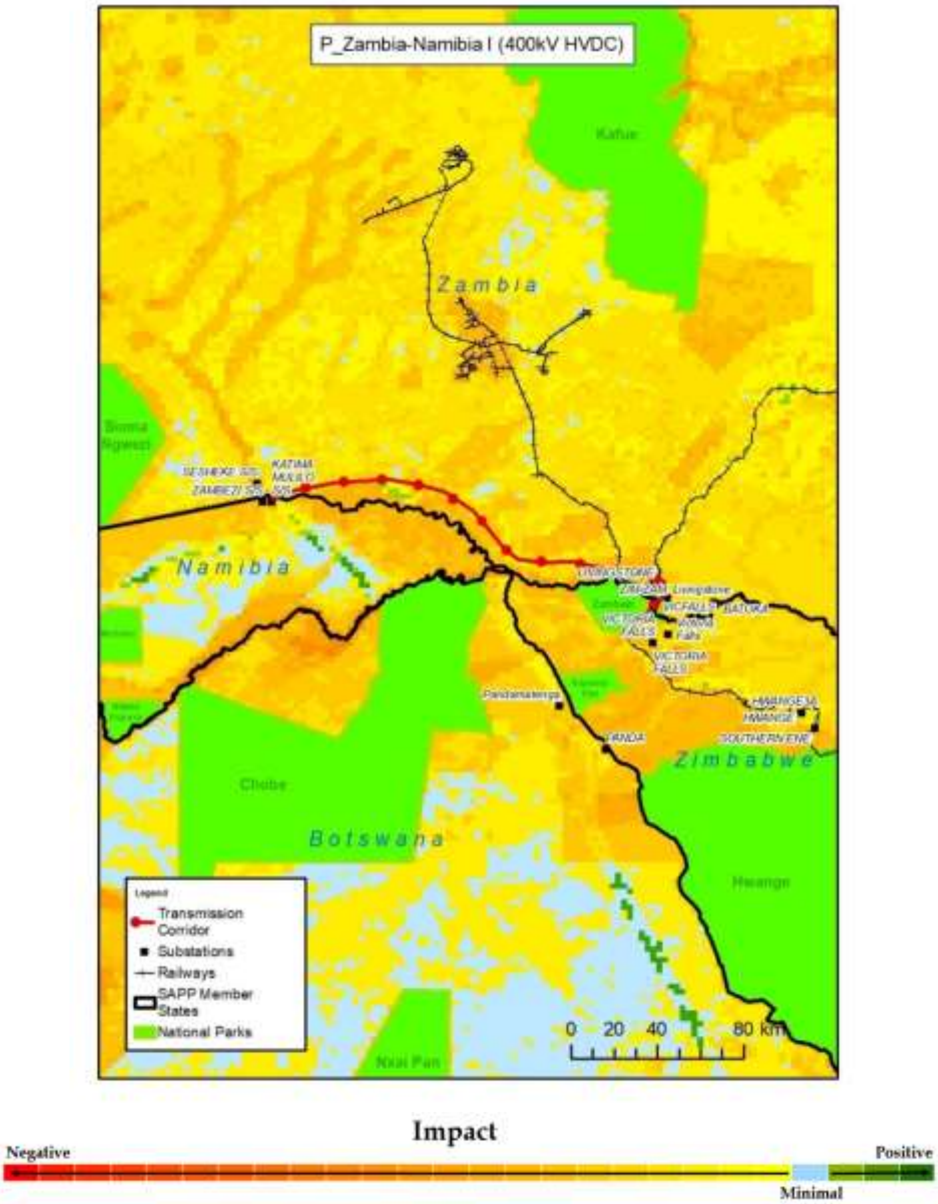


Table 125 GIS Analysis of P_Zambia-Namibia I

Number of GRIDS: 276

Sinks

Mines	9
Big Mines (>5 ha)	4
Small Mines (<5 ha)	5
Industrial Areas	2
Commercial Areas	6
Airports	5
Utilities	6
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	79
Power Lines (plan)	58
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	1
Substations (plan)	0

Limitations

Water	45
Wetland	79
RAMSAR Sites	2
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	276
Min Temp (<5 Deg C)	47

Sinks

Urban / Builtup Areas	59
Towns	3
Night Lights	20
Village/Rural Settlmnt	13
Densely Populated	40
Population Estimates	155,100
Commercial Cultivation	13
Development Corridors	83
Development Hubs	46
Potential Development	0

Resources

Coal Resources	0
PV Resources	19
CSP Resources	19
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	91
National Parks	19
Cultivation	13
Historic Areas	6
Tourist Attractions	8
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	85
Tropical Storms	0
Lightning	10
Wildfires	0
Erosion	232

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	3
Floodplain	158

Constraints

Paved Roads	84
Unpaved Roads	165
Major/Main Roads	89
Railway Lines	20
Railway Stations	2

Background Info

Tall Bushes / Trees	220
Low Vegetation	276
Grasslands	275
Bare Earth	186

Table 126 P_MozC-Zimbabwe I (400kV HVAC)	
Component A	
Component B	
Component C	
Voltage (kV)	400 AC
Capacity (MW)	
Start	Inchope
End	Orange Grove
Other substations	

Figure 18 Map of P_MozC-Zimbabwe I

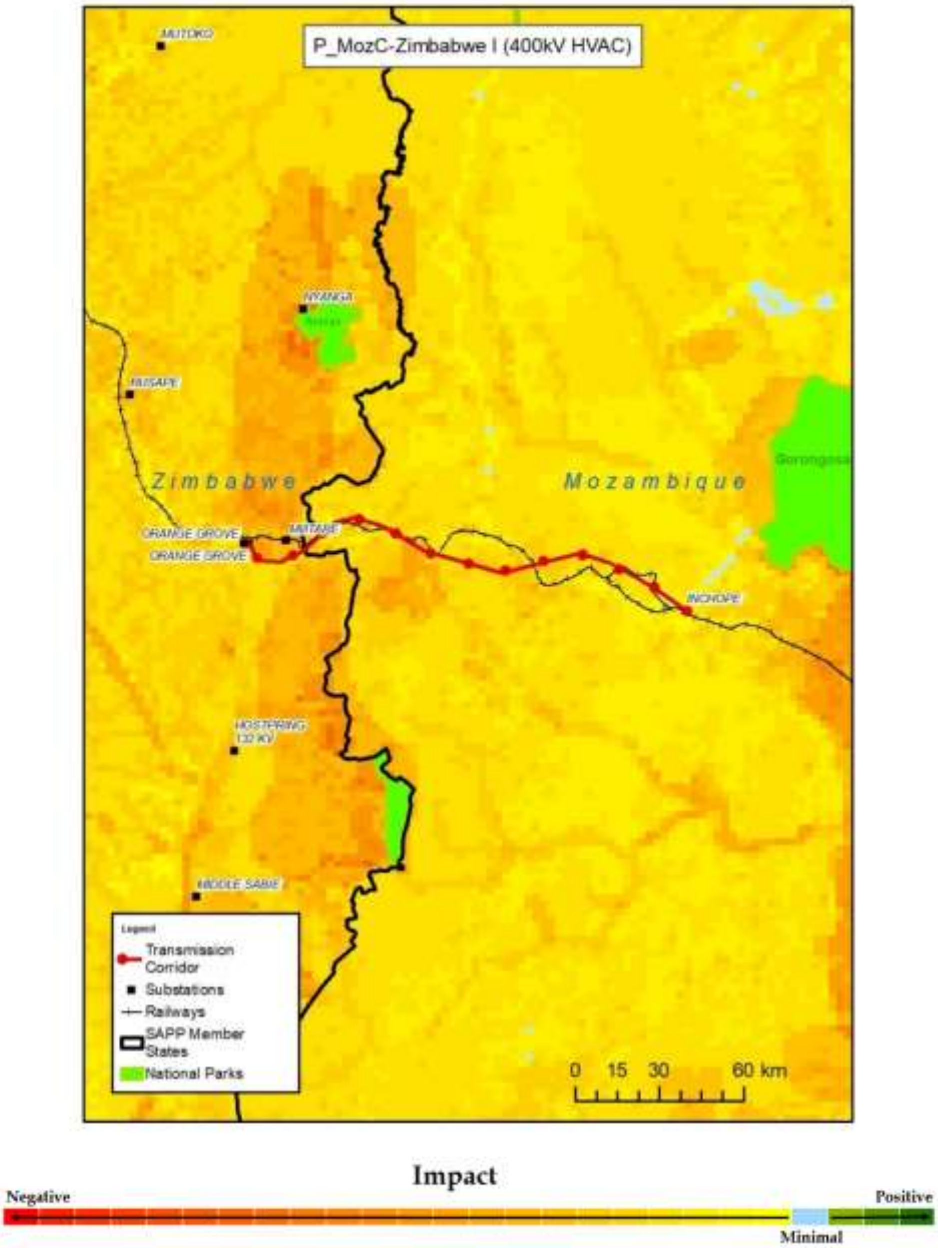


Table 127 GIS Analysis of P_MozC-Zimbabwe I

Number of GRIDS: 229

Sinks

Mines	36
Big Mines (>5 ha)	17
Small Mines (<5 ha)	23
Industrial Areas	0
Commercial Areas	3
Airports	1
Utilities	1
Harbours	0
Reservoirs	1

Sources

Power Lines (exist)	52
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	4
Substations (plan)	1

Limitations

Water	26
Wetland	9
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	18

Weather

Annual Precipitation	191
Max Temp (> 30Deg C)	183
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	52
Towns	1
Night Lights	7
Village/Rural Settlmnt	43
Densely Populated	113
Population Estimates	244,515
Commercial Cultivation	10
Development Corridors	86
Development Hubs	54
Potential Development	0

Resources

Coal Resources	0
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	3
National Parks	3
Cultivation	10
Historic Areas	3
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	32
Lightning	0
Wildfires	0
Erosion	219

Sinks

Load Centres	0

Commodities

Gold	1
Copper	13
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	33
Floodplain	63

Constraints

Paved Roads	85
Unpaved Roads	143
Major/Main Roads	86
Railway Lines	66
Railway Stations	1

Background Info

Tall Bushes / Trees	229
Low Vegetation	229
Grasslands	229
Bare Earth	17

Table 128 P_MozN-Zambia (330kV HVAC)	
Component A	
Component B	
Component C	
Voltage (kV)	400 AC
Capacity (MW)	
Start	Songo
End	Msoro
Other substations	

Figure 19 Map of P_MozN-Zambia

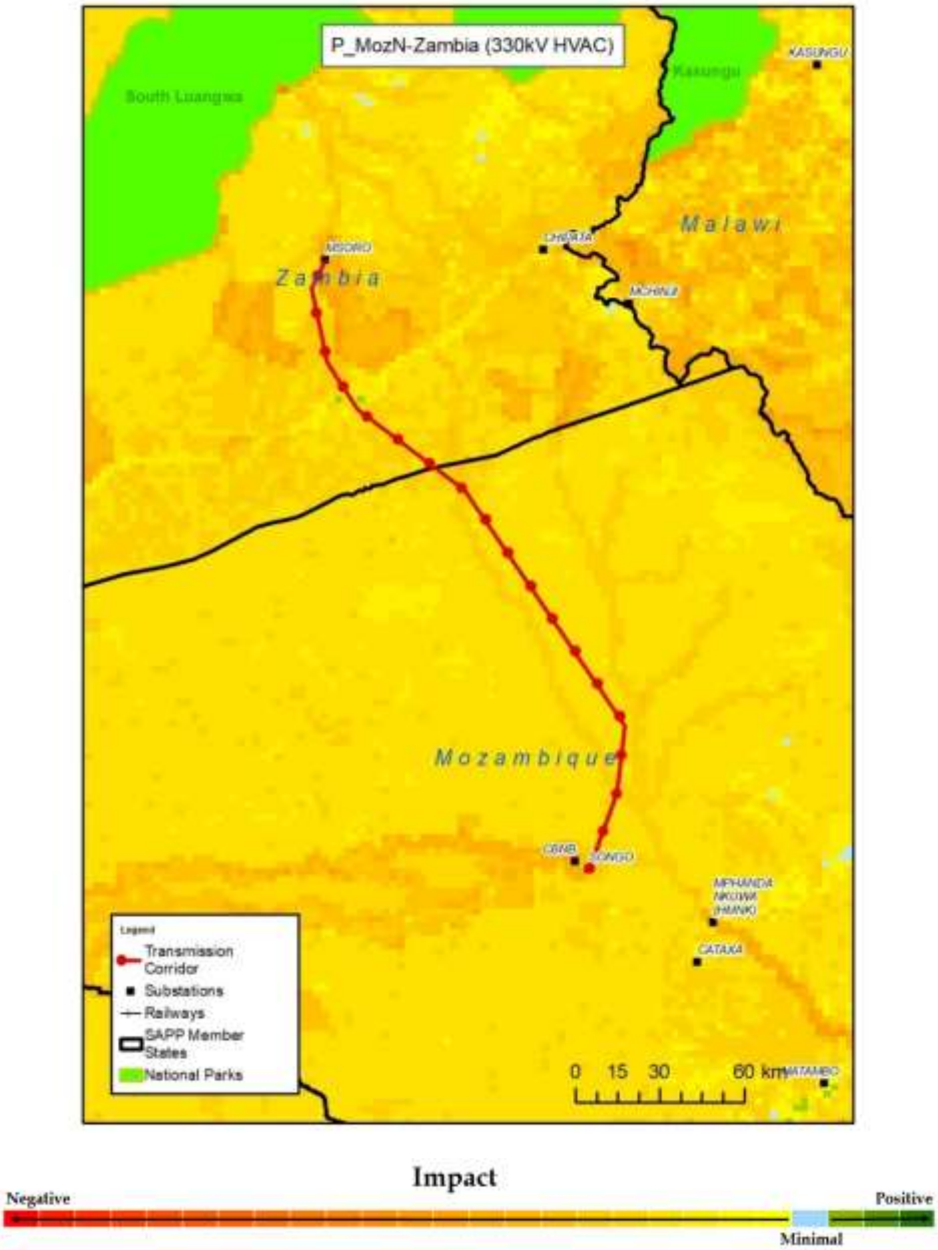


Table 129 GIS Analysis of P_MozN-Zambia

Number of GRIDS: 344

Sinks

Mines	3
Big Mines (>5 ha)	2
Small Mines (<5 ha)	1
Industrial Areas	0
Commercial Areas	2
Airports	3
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	31
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	1
Substations (plan)	1

Limitations

Water	44
Wetland	2
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	141
Max Temp (> 30Deg C)	344
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	38
Towns	2
Night Lights	9
Village/Rural Settlmnt	25
Densely Populated	64
Population Estimates	97,198
Commercial Cultivation	0
Development Corridors	5
Development Hubs	3
Potential Development	0

Resources

Coal Resources	0
PV Resources	48
CSP Resources	48
Wind Resources	73
Undiscovered Oil / Gas	0

Land Use

Protected Areas	13
National Parks	0
Cultivation	0
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	60
Tropical Storms	0
Lightning	1
Wildfires	0
Erosion	339

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	36
Floodplain	97

Constraints

Paved Roads	67
Unpaved Roads	121
Major/Main Roads	66
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	339
Low Vegetation	344
Grasslands	344
Bare Earth	197

Table 130 P_Botswana -South Africa II (400 kV HVAC)	
Component A	
Component B	
Component C	2031
Voltage (kV)	400 AC
Capacity (MW)	700
Start	Isang
End	Watershed
Other substations	

Figure 20 Map of P_Botswana -South Africa II

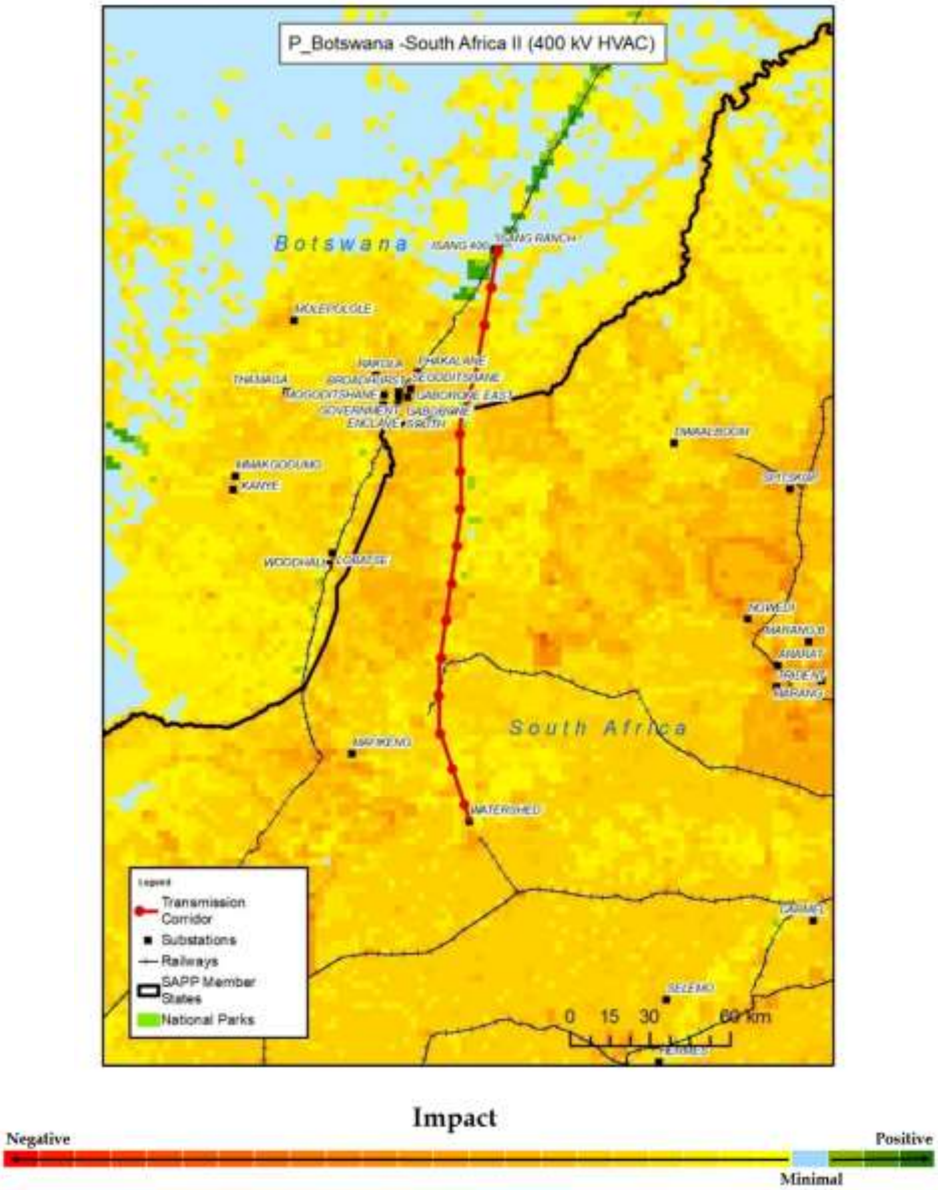


Table 131 GIS Analysis of P_Botswana -South Africa II

Number of GRIDS: 242

Sinks

Mines	48
Big Mines (>5 ha)	17
Small Mines (<5 ha)	32
Industrial Areas	0
Commercial Areas	3
Airports	1
Utilities	0
Harbours	0
Reservoirs	1

Sources

Power Lines (exist)	15
Power Lines (plan)	15
Power Plants (exist)	0
Power Plants (plan)	1
Substations (exist)	2
Substations (plan)	0

Limitations

Water	13
Wetland	0
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	187
Min Temp (<5 Deg C)	242

Sinks

Urban / Builtup Areas	24
Towns	0
Night Lights	8
Village/Rural Settlmnt	9
Densely Populated	17
Population Estimates	35,533
Commercial Cultivation	62
Development Corridors	39
Development Hubs	25
Potential Development	0

Resources

Coal Resources	0
PV Resources	240
CSP Resources	58
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	12
National Parks	0
Cultivation	62
Historic Areas	4
Tourist Attractions	0
Tribal/Customary Land	21

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	17
Lightning	65
Wildfires	0
Erosion	207

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	5

Topography

Slope (>30%)	2
Floodplain	34

Constraints

Paved Roads	70
Unpaved Roads	161
Major/Main Roads	64
Railway Lines	17
Railway Stations	1

Background Info

Tall Bushes / Trees	169
Low Vegetation	240
Grasslands	217
Bare Earth	44

Table 132 E_South Africa-Zimbabwe I (400kV HVAC)	
Component A	Committed – 2021 in all components
Component B	Committed – 2021 in all components
Component C	Committed – 2021 in all components
Voltage (kV)	400 AC
Capacity (MW)	300 MW initially, 200 MW later on
Start	Triangle
End	Nzehelele
Other substations	

Figure 21 Map of E_South Africa-Zimbabwe I

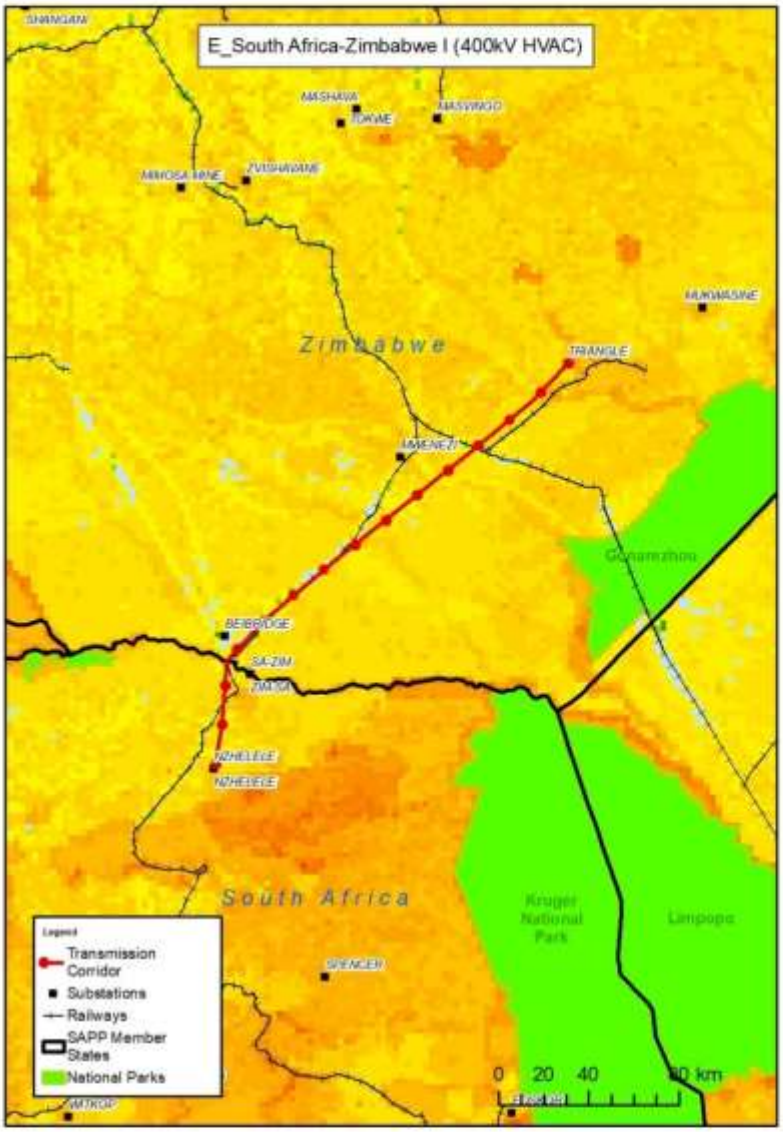


Table 133 GIS Analysis of E_South Africa-Zimbabwe I

Number of GRIDS: 321

Sinks

Mines	16
Big Mines (>5 ha)	4
Small Mines (<5 ha)	12
Industrial Areas	0
Commercial Areas	1
Airports	3
Utilities	1
Harbours	0
Reservoirs	26

Sources

Power Lines (exist)	4
Power Lines (plan)	4
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	1
Substations (plan)	1

Limitations

Water	43
Wetland	3
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	321
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	13
Towns	1
Night Lights	16
Village/Rural Settlmnt	6
Densely Populated	4
Population Estimates	24,886
Commercial Cultivation	40
Development Corridors	104
Development Hubs	17
Potential Development	0

Resources

Coal Resources	22
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	2
National Parks	0
Cultivation	40
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	4

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	25
Lightning	0
Wildfires	0
Erosion	267

Sinks

Load Centres	1

Commodities

Gold	0
Copper	15
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	0
Floodplain	19

Constraints

Paved Roads	88
Unpaved Roads	216
Major/Main Roads	82
Railway Lines	75
Railway Stations	0

Background Info

Tall Bushes / Trees	289
Low Vegetation	316
Grasslands	318
Bare Earth	53

Table 134 P_Zimbabwe-South Africa I (400kV HVAC)	
Component A	
Component B	2038
Component C	2039
Voltage (kV)	400 AC
Capacity (MW)	200 (higher early on in study period)
Start	Insukamini
End	Nzehelele
Other substations	

Figure 22 Map of P_Zimbabwe-South Africa I

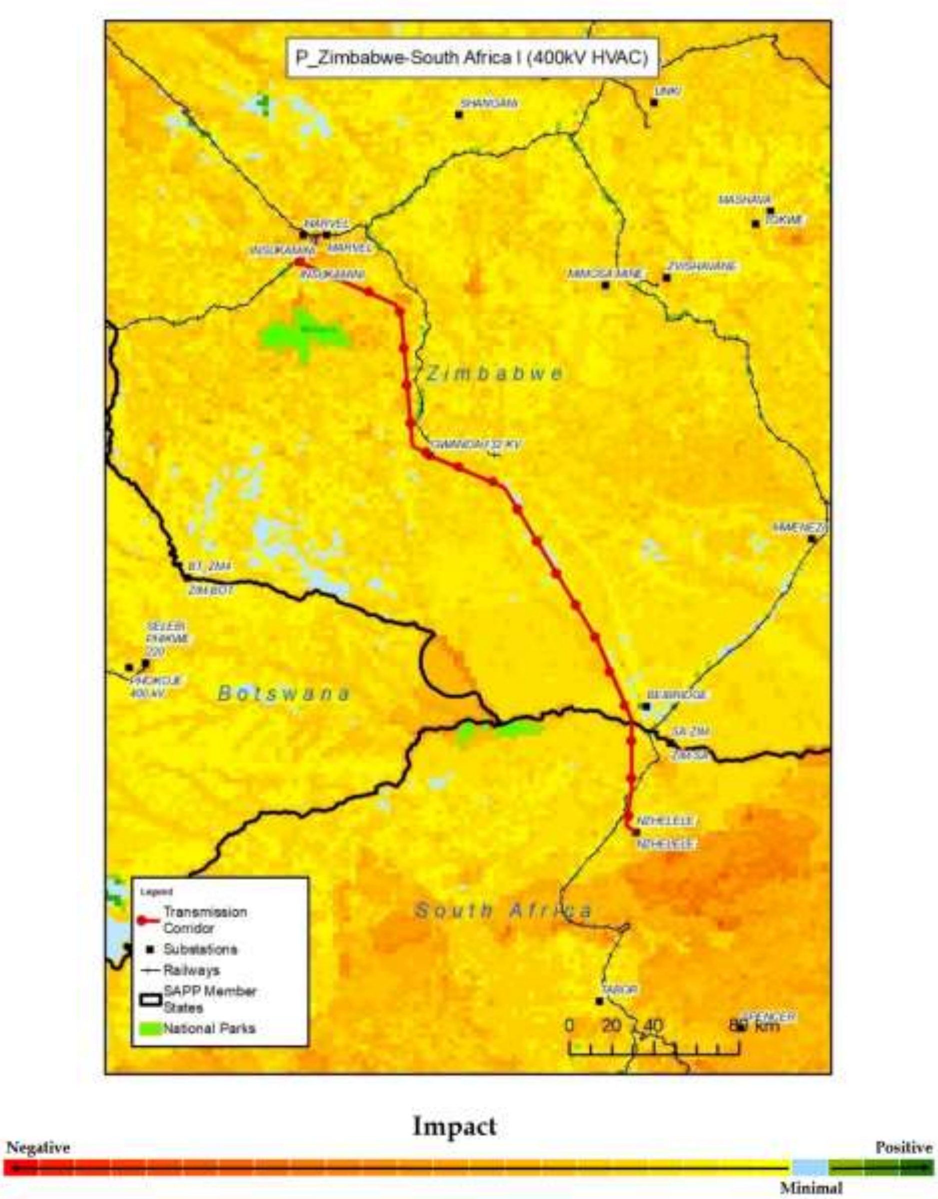


Table 135 GIS Analysis of P_Zimbabwe-South Africa I

Number of GRIDS: 424

Sinks

Mines	27
Big Mines (>5 ha)	13
Small Mines (<5 ha)	16
Industrial Areas	0
Commercial Areas	0
Airports	1
Utilities	0
Harbours	0
Reservoirs	7

Sources

Power Lines (exist)	10
Power Lines (plan)	5
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	2
Substations (plan)	1

Limitations

Water	150
Wetland	10
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	386
Min Temp (<5 Deg C)	196

Sinks

Urban / Builtup Areas	12
Towns	1
Night Lights	1
Village/Rural Settlmnt	9
Densely Populated	8
Population Estimates	48,901
Commercial Cultivation	31
Development Corridors	94
Development Hubs	2
Potential Development	0

Resources

Coal Resources	66
PV Resources	56
CSP Resources	28
Wind Resources	66
Undiscovered Oil / Gas	0

Land Use

Protected Areas	10
National Parks	0
Cultivation	31
Historic Areas	4
Tourist Attractions	3
Tribal/Customary Land	4

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	29
Lightning	0
Wildfires	0
Erosion	357

Sinks

Load Centres	0

Commodities

Gold	0
Copper	5
Aluminium	0
Diamonds	15
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	6
Floodplain	46

Constraints

Paved Roads	46
Unpaved Roads	317
Major/Main Roads	36
Railway Lines	19
Railway Stations	1

Background Info

Tall Bushes / Trees	392
Low Vegetation	424
Grasslands	422
Bare Earth	121

Table 136 P_Zambia-Tanzania IIa (500kV HVDC) and IIb (500kV HVDC)	
Component A	
Component B	2030
Component C	
Voltage (kV)	500 ADC
Capacity (MW)	1500
Start	Kabwe
End	Mbeya
Other substations	Pensulo, Mpika, Nakonde

Figure 23 Map of P_Zambia-Tanzania IIa and IIb

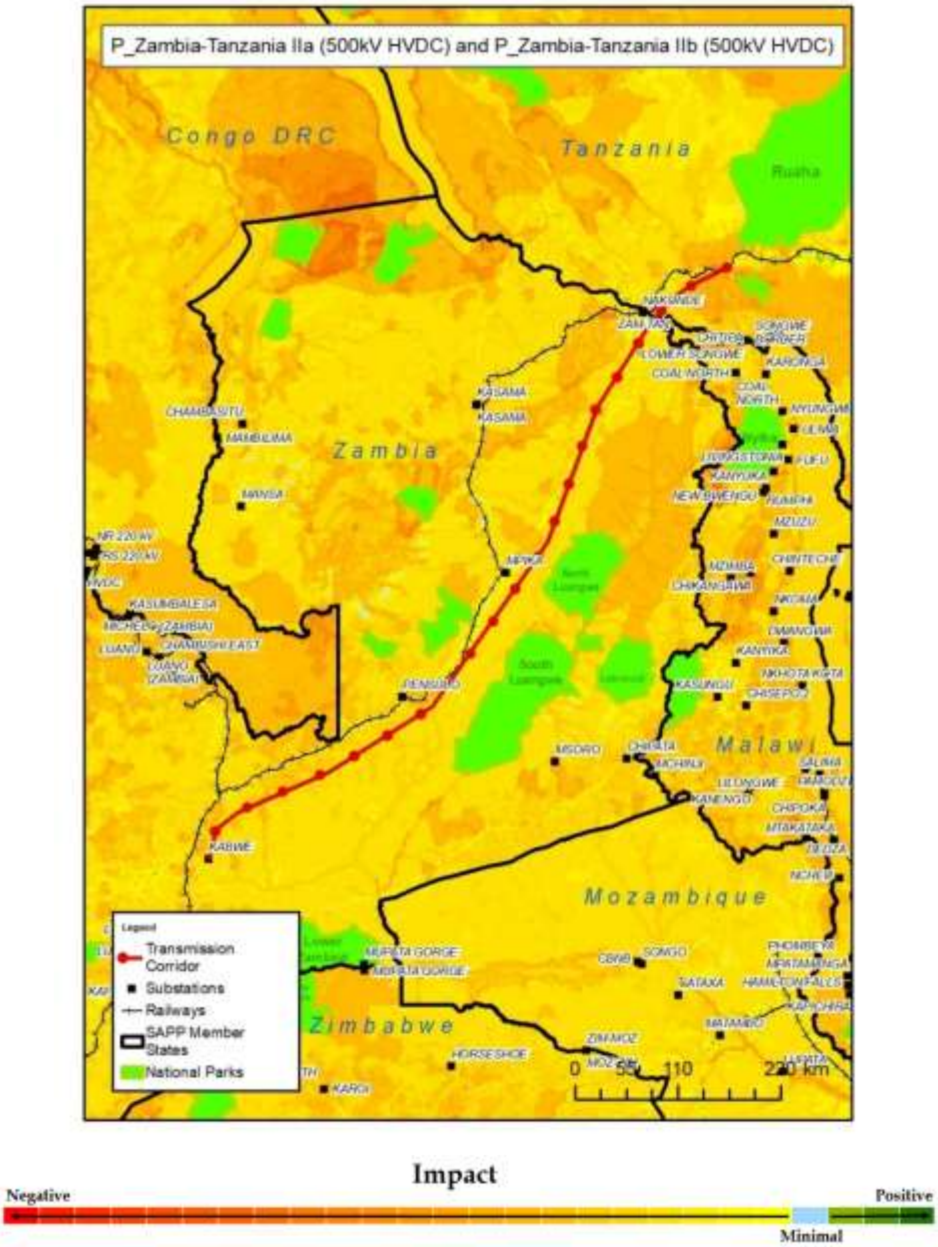


Table 137 GIS Analysis of P_Zambia-Tanzania IIa and IIb

Number of GRIDS: 1,170

Sinks

Mines	5
Big Mines (>5 ha)	4
Small Mines (<5 ha)	2
Industrial Areas	0
Commercial Areas	0
Airports	0
Utilities	1
Harbours	0
Reservoirs	1

Sources

Power Lines (exist)	61
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	81
Wetland	13
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	944
Max Temp (> 30Deg C)	758
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	114
Towns	0
Night Lights	1
Village/Rural Settlmnt	62
Densely Populated	103
Population Estimates	214,454
Commercial Cultivation	46
Development Corridors	92
Development Hubs	14
Potential Development	0

Resources

Coal Resources	55
PV Resources	19
CSP Resources	19
Wind Resources	26
Undiscovered Oil / Gas	0

Land Use

Protected Areas	19
National Parks	0
Cultivation	46
Historic Areas	3
Tourist Attractions	1
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	27
Earthquakes	150
Tropical Storms	0
Lightning	53
Wildfires	0
Erosion	1,161

Sinks

Load Centres	2

Commodities

Gold	0
Copper	4
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	5

Topography

Slope (>30%)	31
Floodplain	572

Constraints

Paved Roads	60
Unpaved Roads	711
Major/Main Roads	78
Railway Lines	25
Railway Stations	2

Background Info

Tall Bushes / Trees	1,098
Low Vegetation	1,102
Grasslands	1,157
Bare Earth	806

Table 138P_MozN-MozS Ia (500kV HVDC) and Ib (500kV HVDC)	
Component A	1325 MW in 2025and 1325 MW in 2032
Component B	2027
Component C	2028
Voltage (kV)	500 DC
Capacity (MW)	2650 MW (in stages of 1325 MW)
Start	Cataxa
End	Maputo
Other substations	

Figure 24 Map of P_MozN-MozS Ia and Ib

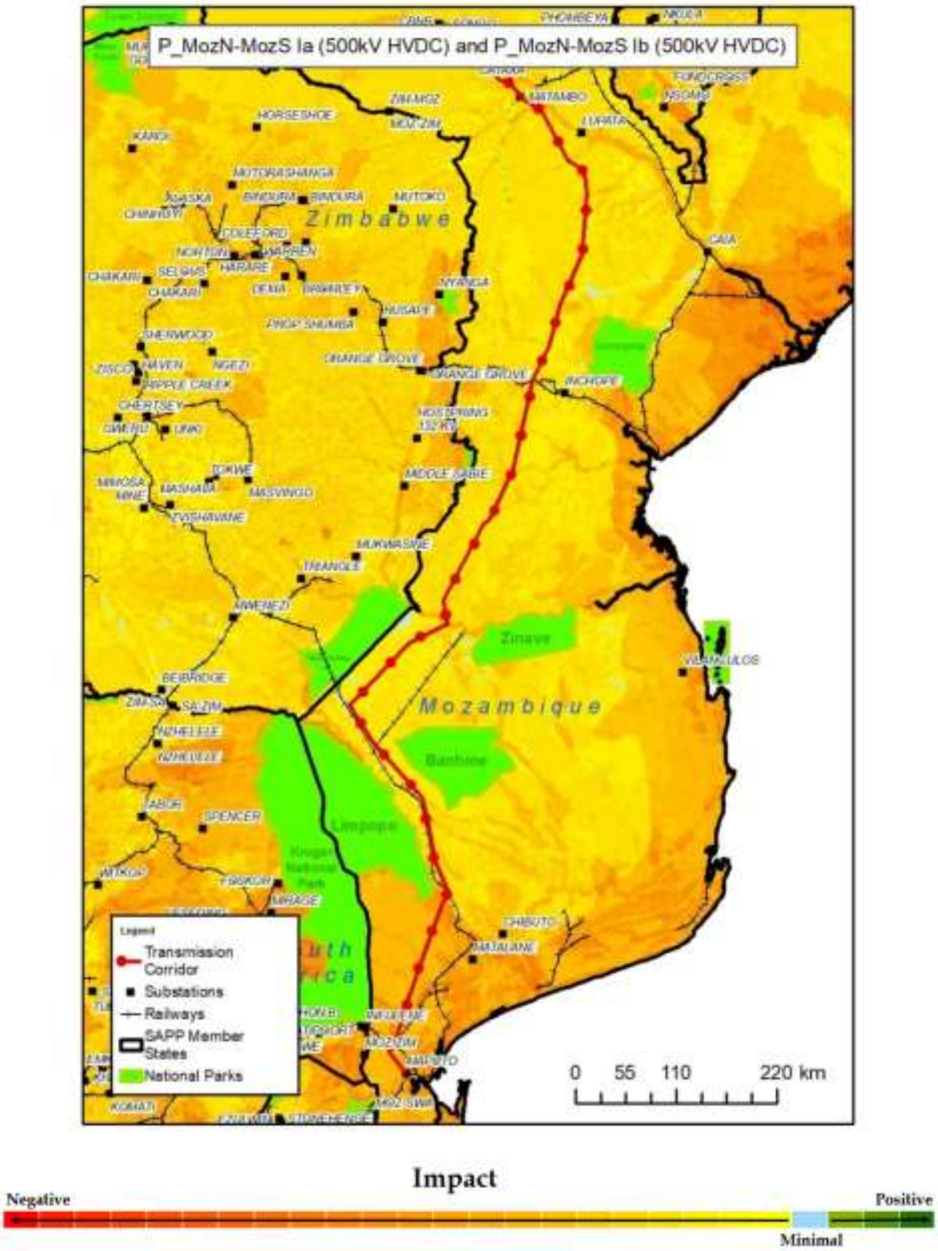


Table 139 GIS Analysis of P_MozN-MozS Ia and Ib

Number of GRIDS: 1,638

Sinks

Mines	38
Big Mines (>5 ha)	19
Small Mines (<5 ha)	21
Industrial Areas	0
Commercial Areas	2
Airports	2
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	60
Power Lines (plan)	4
Power Plants (exist)	2
Power Plants (plan)	0
Substations (exist)	2
Substations (plan)	2

Limitations

Water	132
Wetland	82
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	278

Weather

Annual Precipitation	293
Max Temp (> 30Deg C)	1,638
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	38
Towns	1
Night Lights	5
Village/Rural Settlmnt	61
Densely Populated	185
Population Estimates	352,955
Commercial Cultivation	31
Development Corridors	95
Development Hubs	13
Potential Development	0

Resources

Coal Resources	126
PV Resources	215
CSP Resources	0
Wind Resources	192
Undiscovered Oil / Gas	0

Land Use

Protected Areas	0
National Parks	0
Cultivation	31
Historic Areas	0
Tourist Attractions	1
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	152
Tropical Storms	114
Lightning	66
Wildfires	0
Erosion	1,172

Sinks

Load Centres	14

Commodities

Gold	0
Copper	0
Aluminium	1
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	4
Floodplain	519

Constraints

Paved Roads	97
Unpaved Roads	512
Major/Main Roads	118
Railway Lines	54
Railway Stations	3

Background Info

Tall Bushes / Trees	1,598
Low Vegetation	1,634
Grasslands	1,590
Bare Earth	118

Table 140 P_MozN-MozC I (400kV HVAC) and P_MozC-MozS I (400kV HVAC)	
Component A	
Component B	2027
Component C	2028
Voltage (kV)	400 AC
Capacity (MW)	400
Start	Cataxa
End	Maputo
Other substations	Matambo, Lupata, Inchope, Vilanculos, Chibuto, Matalane, Moamba

Figure 25 Map of P_MozN-MozC I and P_MozC-MozS I

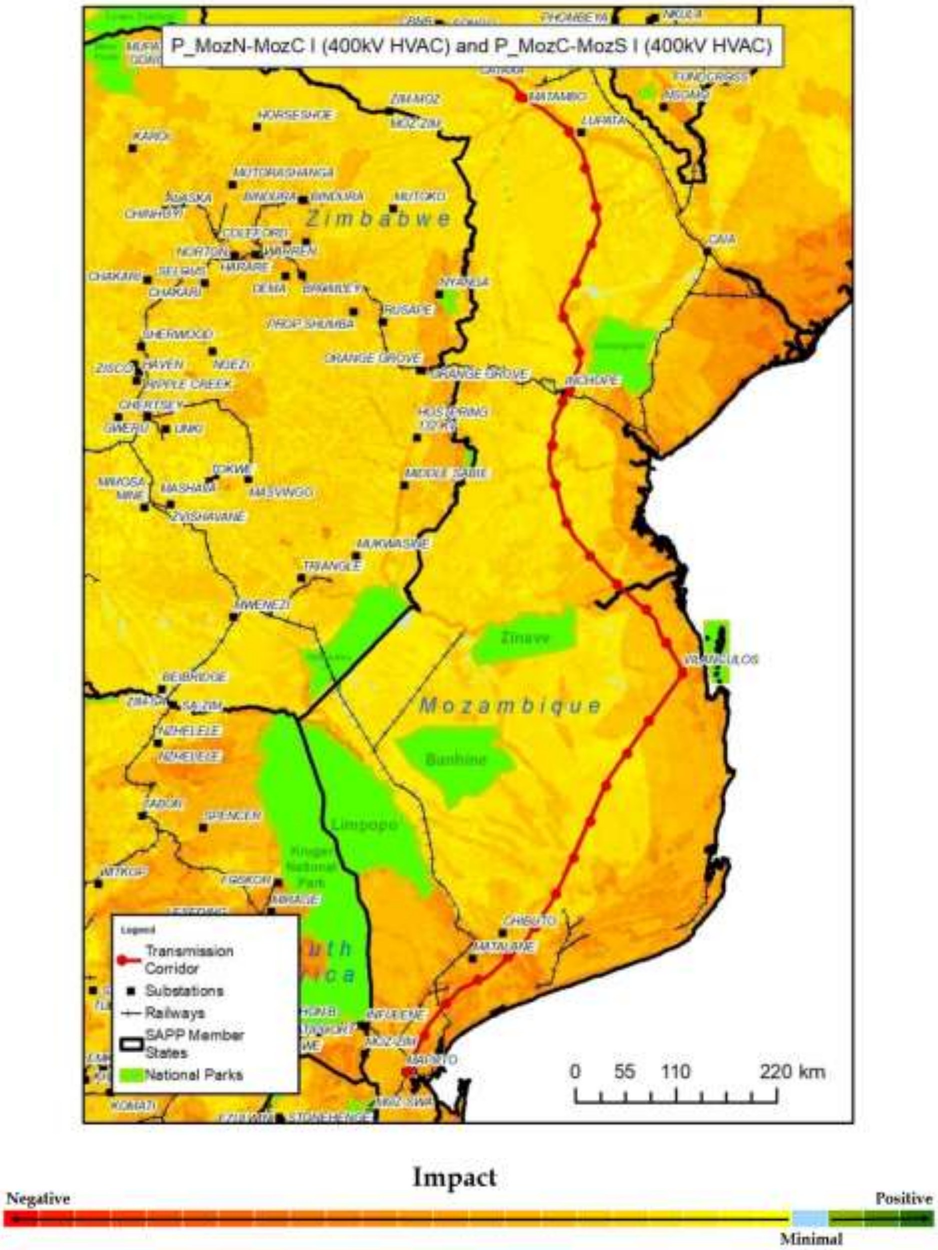


Table 141 GIS Analysis of P_MozN-MozC I and P_MozC-MozS I

Number of GRIDS: 1,700

Sinks

Mines	29
Big Mines (>5 ha)	9
Small Mines (<5 ha)	21
Industrial Areas	1
Commercial Areas	3
Airports	4
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	43
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	3
Substations (plan)	5

Limitations

Water	127
Wetland	239
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	527

Weather

Annual Precipitation	286
Max Temp (> 30Deg C)	1,700
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	49
Towns	0
Night Lights	12
Village/Rural Settlmnt	77
Densely Populated	234
Population Estimates	484,054
Commercial Cultivation	24
Development Corridors	125
Development Hubs	24
Potential Development	0

Resources

Coal Resources	25
PV Resources	142
CSP Resources	0
Wind Resources	176
Undiscovered Oil / Gas	411

Land Use

Protected Areas	12
National Parks	12
Cultivation	24
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	92
Tropical Storms	182
Lightning	67
Wildfires	0
Erosion	1,323

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	16
Floodplain	671

Constraints

Paved Roads	228
Unpaved Roads	564
Major/Main Roads	165
Railway Lines	17
Railway Stations	0

Background Info

Tall Bushes / Trees	1,658
Low Vegetation	1,695
Grasslands	1,628
Bare Earth	167

Table 142 C_Zambia-Zimbabwe I (330kV HVAC)	
Component A	Committed – 2020 in all components
Component B	Committed – 2020 in all components
Component C	Committed – 2020 in all components
Voltage (kV)	400 AC
Capacity (MW)	250
Start	Livingstone
End	Hwange
Other substations	Victoria Falls

Figure 26 Map of C_Zambia-Zimbabwe I

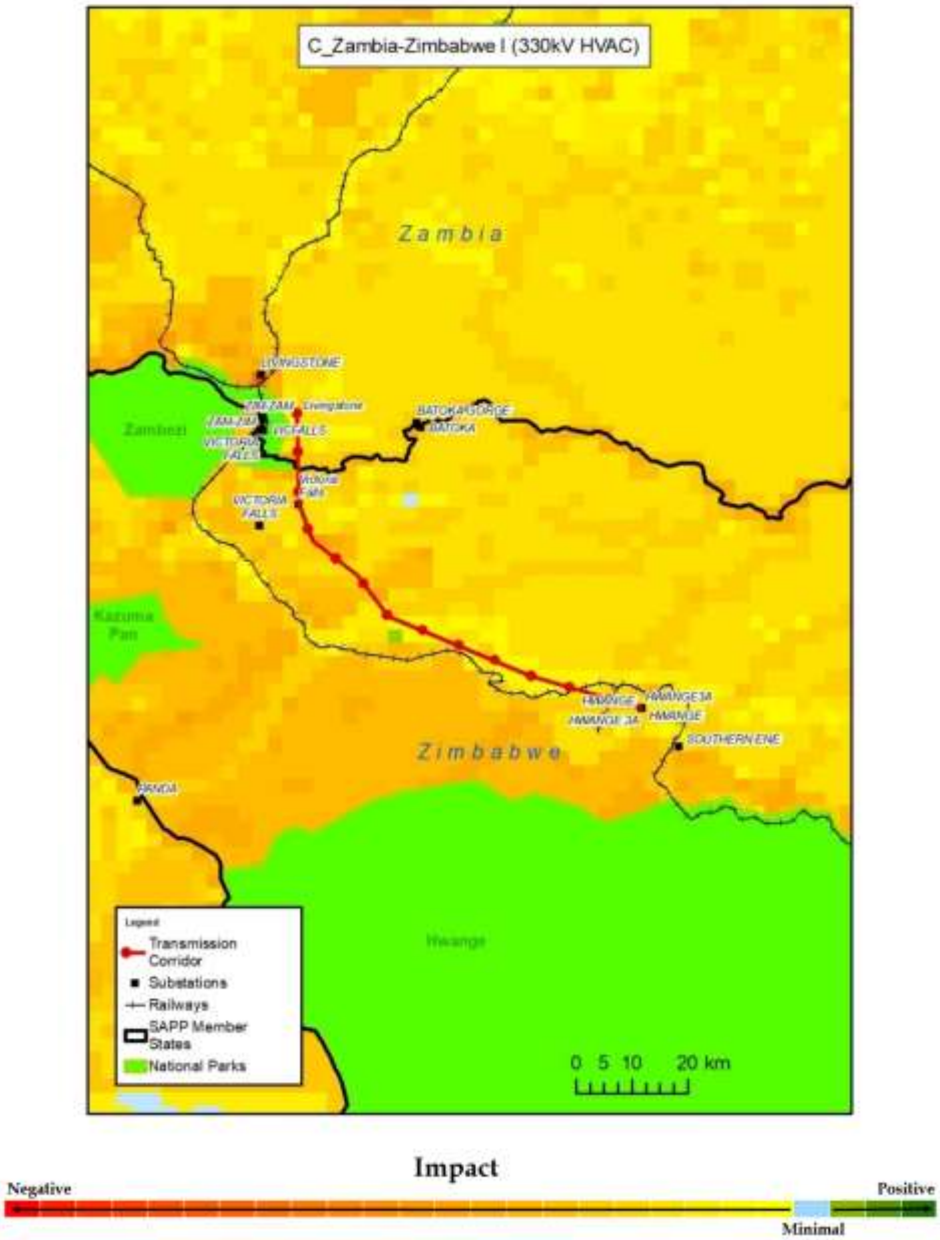


Table 143 GIS Analysis of C_Zambia-Zimbabwe I

Number of GRIDS: 113

Sinks

Mines	14
Big Mines (>5 ha)	13
Small Mines (<5 ha)	1
Industrial Areas	1
Commercial Areas	1
Airports	0
Utilities	1
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	1
Power Lines (plan)	6
Power Plants (exist)	1
Power Plants (plan)	0
Substations (exist)	1
Substations (plan)	0

Limitations

Water	29
Wetland	0
RAMSAR Sites	2
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	113
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	15
Towns	0
Night Lights	2
Village/Rural Settlmnt	10
Densely Populated	4
Population Estimates	8,999
Commercial Cultivation	0
Development Corridors	52
Development Hubs	10
Potential Development	0

Resources

Coal Resources	19
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	27
National Parks	3
Cultivation	0
Historic Areas	2
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	9
Wildfires	0
Erosion	108

Sinks

Load Centres	12

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	4
Floodplain	33

Constraints

Paved Roads	43
Unpaved Roads	85
Major/Main Roads	34
Railway Lines	27
Railway Stations	1

Background Info

Tall Bushes / Trees	110
Low Vegetation	113
Grasslands	111
Bare Earth	73

Table 144 P_Botswana-Zimbabwe I (330kV HVAC)	
Component A	
Component B	
Component C	
Voltage (kV)	
Capacity (MW)	
Start	Victoria Falls
End	Pandamatenga
Other substations	

Figure 27 Map of P_Botswana-Zimbabwe I

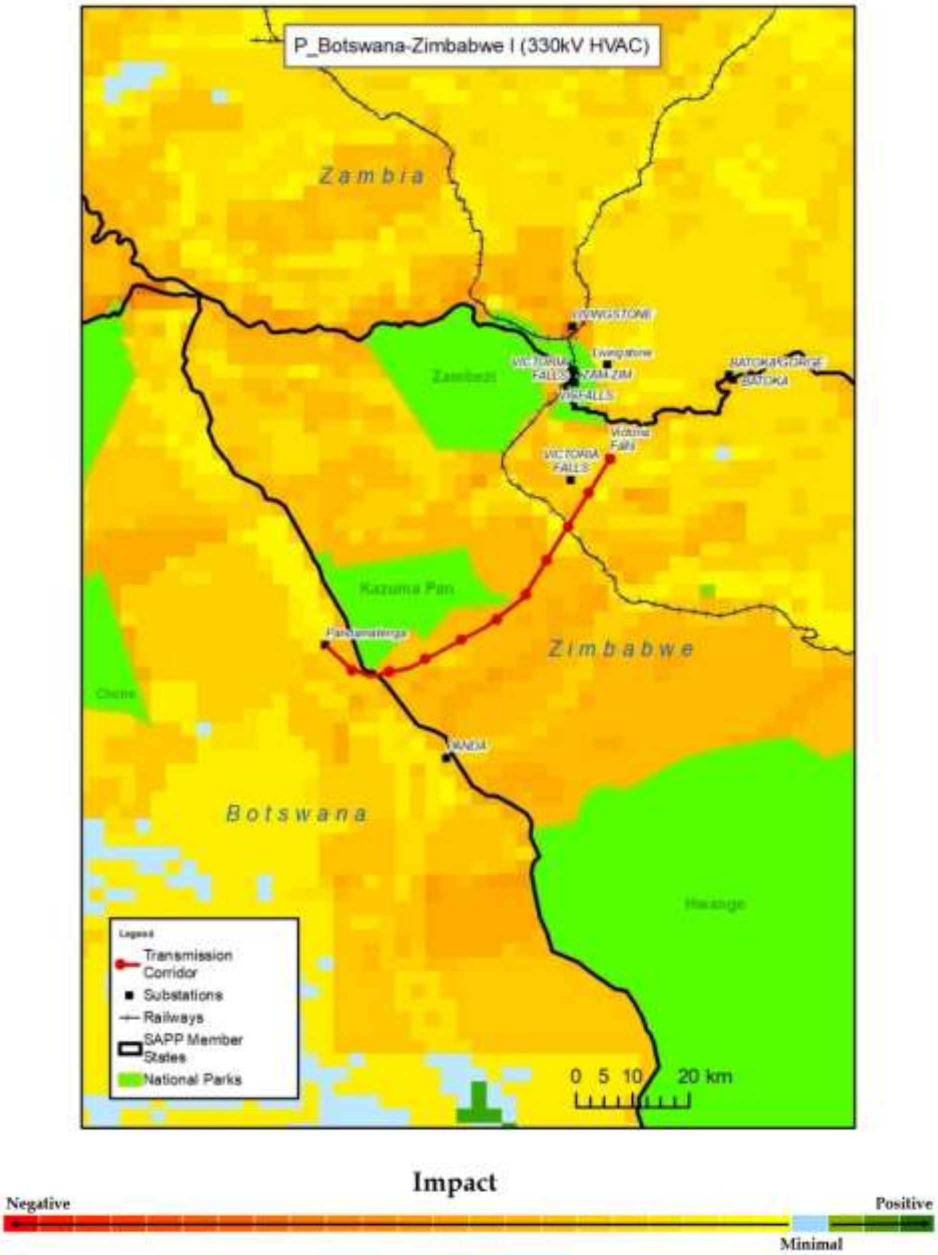


Table 145 GIS Analysis of P_Botswana-Zimbabwe I

Number of GRIDS: 100

Sinks

Mines	1
Big Mines (>5 ha)	1
Small Mines (<5 ha)	0
Industrial Areas	0
Commercial Areas	0
Airports	1
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	0
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	1
Substations (plan)	0

Limitations

Water	13
Wetland	0
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	100
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	2
Towns	0
Night Lights	0
Village/Rural Settlmnt	7
Densely Populated	0
Population Estimates	1,155
Commercial Cultivation	0
Development Corridors	22
Development Hubs	0
Potential Development	0

Resources

Coal Resources	0
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	78
National Parks	15
Cultivation	0
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	6
Lightning	7
Wildfires	0
Erosion	82

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	0
Floodplain	11

Constraints

Paved Roads	13
Unpaved Roads	49
Major/Main Roads	13
Railway Lines	5
Railway Stations	0

Background Info

Tall Bushes / Trees	97
Low Vegetation	100
Grasslands	100
Bare Earth	50

Table 146 P_Lesotho-South Africa III (132kV HVAC)	
Component A	
Component B	2020
Component C	2020
Voltage (kV)	132
Capacity (MW)	50 - 60
Start	Khukhune
End	Clarens
Other substations	

Figure 28 Map of P_Lesotho-South Africa III

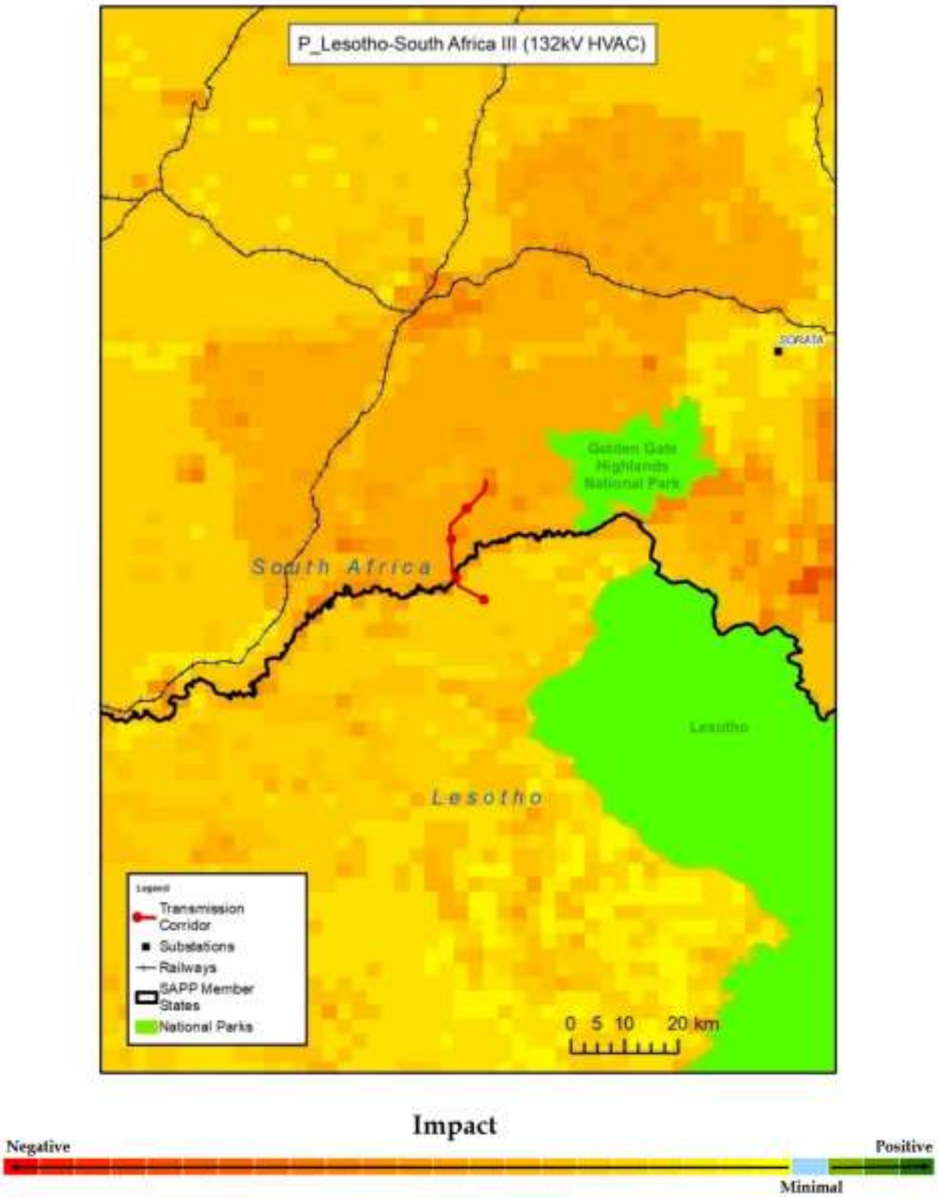


Table 147 GIS Analysis of P_Lesotho-South Africa III

Number of GRIDS: 43

Sinks

Mines	8
Big Mines (>5 ha)	0
Small Mines (<5 ha)	7
Industrial Areas	1
Commercial Areas	1
Airports	0
Utilities	1
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	5
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	0
Wetland	0
RAMSAR Sites	0
Important Bird Areas	32
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	0
Min Temp (<5 Deg C)	43

Sinks

Urban / Builtup Areas	18
Towns	0
Night Lights	0
Village/Rural Settlmnt	15
Densely Populated	15
Population Estimates	20,715
Commercial Cultivation	29
Development Corridors	0
Development Hubs	0
Potential Development	0

Resources

Coal Resources	21
PV Resources	43
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	1
National Parks	0
Cultivation	29
Historic Areas	3
Tourist Attractions	1
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	7
Lightning	20
Wildfires	0
Erosion	43

Sinks

Load Centres	5

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	22
Floodplain	4

Constraints

Paved Roads	22
Unpaved Roads	35
Major/Main Roads	22
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	43
Low Vegetation	43
Grasslands	14
Bare Earth	25

Table 148 P_Malawi-MozN I (400kV HVAC), II (400kV HVAC) and III (400kV HVAC)

Component A	
Component B	2020, 2022, and 2033
Component C	2020 and 2027
Voltage (kV)	400 AC
Capacity (MW)	First line 200 MW, second adds 800 MW, third adds another 800 MW
Start	Matamba
End	Matamba SDE
Other substations	Ncondezi, Phombeya

Figure 29 Map of P_Malawi-MozN I, II and III

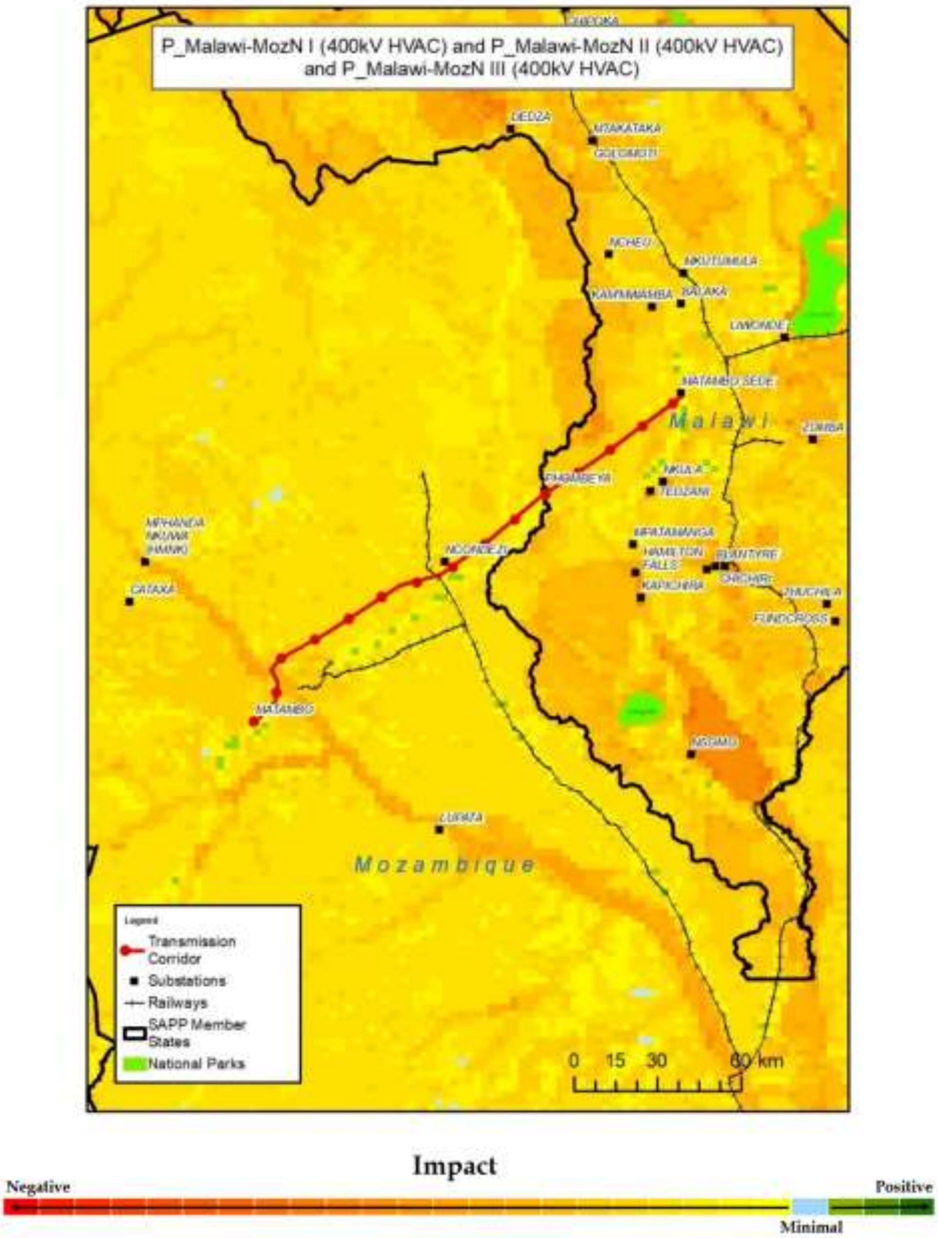


Table 149 GIS Analysis of P_Malawi-MozN I, II and III

Number of GRIDS: 269

Sinks

Mines	8
Big Mines (>5 ha)	6
Small Mines (<5 ha)	1
Industrial Areas	1
Commercial Areas	4
Airports	2
Utilities	1
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	24
Power Lines (plan)	84
Power Plants (exist)	0
Power Plants (plan)	2
Substations (exist)	2
Substations (plan)	1

Limitations

Water	14
Wetland	9
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	91
Max Temp (> 30Deg C)	269
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	22
Towns	2
Night Lights	12
Village/Rural Settlmnt	28
Densely Populated	98
Population Estimates	200,730
Commercial Cultivation	1
Development Corridors	37
Development Hubs	30
Potential Development	0

Resources

Coal Resources	79
PV Resources	116
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	0
National Parks	0
Cultivation	1
Historic Areas	1
Tourist Attractions	1
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	7
Tropical Storms	5
Lightning	3
Wildfires	0
Erosion	269

Sinks

Load Centres	5

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	29
Floodplain	44

Constraints

Paved Roads	44
Unpaved Roads	114
Major/Main Roads	42
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	240
Low Vegetation	269
Grasslands	269
Bare Earth	65

Table 150 P_Angola-Namibia I (400kV HVAC)	
Component A	
Component B	2022
Component C	2022
Voltage (kV)	400 AC
Capacity (MW)	250
Start	Khunene
End	Cahama
Other substations	

Figure 30 Map of P_Angola-Namibia I

Table 151 GIS Analysis of P_Angola-Namibia I

Number of GRIDS: 188

Sinks

Mines	1
Big Mines (>5 ha)	1
Small Mines (<5 ha)	0
Industrial Areas	0
Commercial Areas	0
Airports	0
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	16
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	5
Wetland	0
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	188
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	1
Towns	0
Night Lights	0
Village/Rural Settlmnt	2
Densely Populated	0
Population Estimates	7,955
Commercial Cultivation	0
Development Corridors	5
Development Hubs	0
Potential Development	0

Resources

Coal Resources	0
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	0
National Parks	0
Cultivation	0
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	0
Wildfires	0
Erosion	185

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	0
Floodplain	7

Constraints

Paved Roads	37
Unpaved Roads	84
Major/Main Roads	5
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	111
Low Vegetation	188
Grasslands	182
Bare Earth	66

Table 152 Part of P_DRC-Angola III (400kV HVAC)

Component A	
Component B	2033
Component C	2034
Voltage (kV)	400 AC
Capacity (MW)	First line 300 MW, second adds 800 MW, third adds another 800 MW
Start	Nzeto
End	Kapary
Other substations	

Figure 31 Map of Part of P_DRC-Angola III

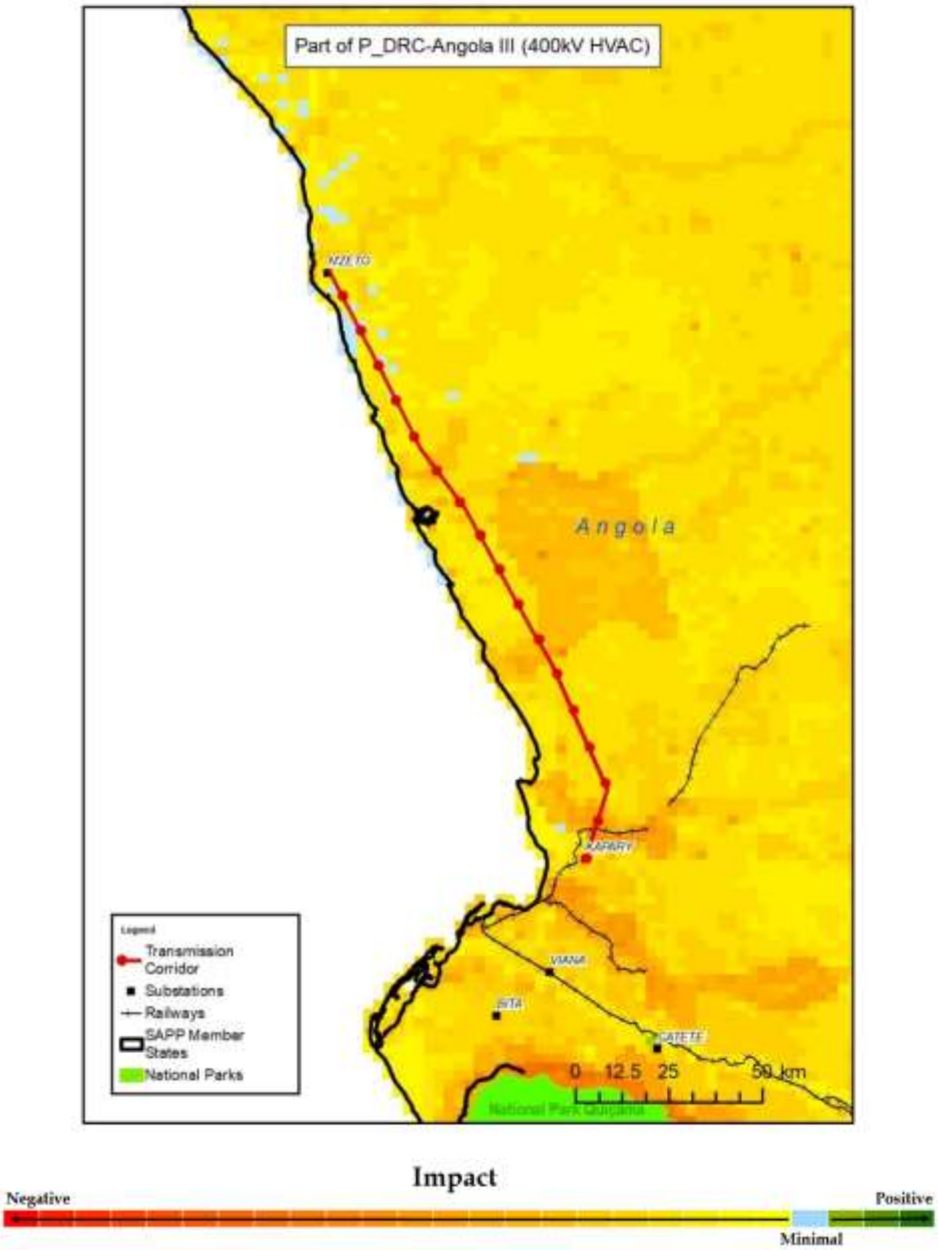


Table 153 GIS Analysis of Part of P_DRC-Angola III

Number of GRIDS: 242

Sinks

Mines	35
Big Mines (>5 ha)	20
Small Mines (<5 ha)	22
Industrial Areas	1
Commercial Areas	2
Airports	1
Utilities	1
Harbours	0
Reservoirs	1

Sources

Power Lines (exist)	2
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	25
Wetland	25
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	242
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	11
Towns	0
Night Lights	2
Village/Rural Settlmnt	5
Densely Populated	6
Population Estimates	20,798
Commercial Cultivation	42
Development Corridors	0
Development Hubs	0
Potential Development	0

Resources

Coal Resources	0
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	171

Land Use

Protected Areas	8
National Parks	0
Cultivation	42
Historic Areas	3
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	0
Wildfires	0
Erosion	151

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	0
Floodplain	169

Constraints

Paved Roads	83
Unpaved Roads	73
Major/Main Roads	61
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	214
Low Vegetation	39
Grasslands	240
Bare Earth	43

Table 154 P_DRC-Angola I (400kV HVAC), II (400kV HVAC) and III (400kV HVAC)

Component A	
Component B	2023, 2023 and 2033
Component C	2020, 2020 and 2034
Voltage (kV)	400 AC
Capacity (MW)	First line 300 MW, second adds 800 MW, third adds another 800 MW
Start	Inga
End	Nzeto
Other substations	

Figure 32 Map of P_DRC-Angola I, II and III

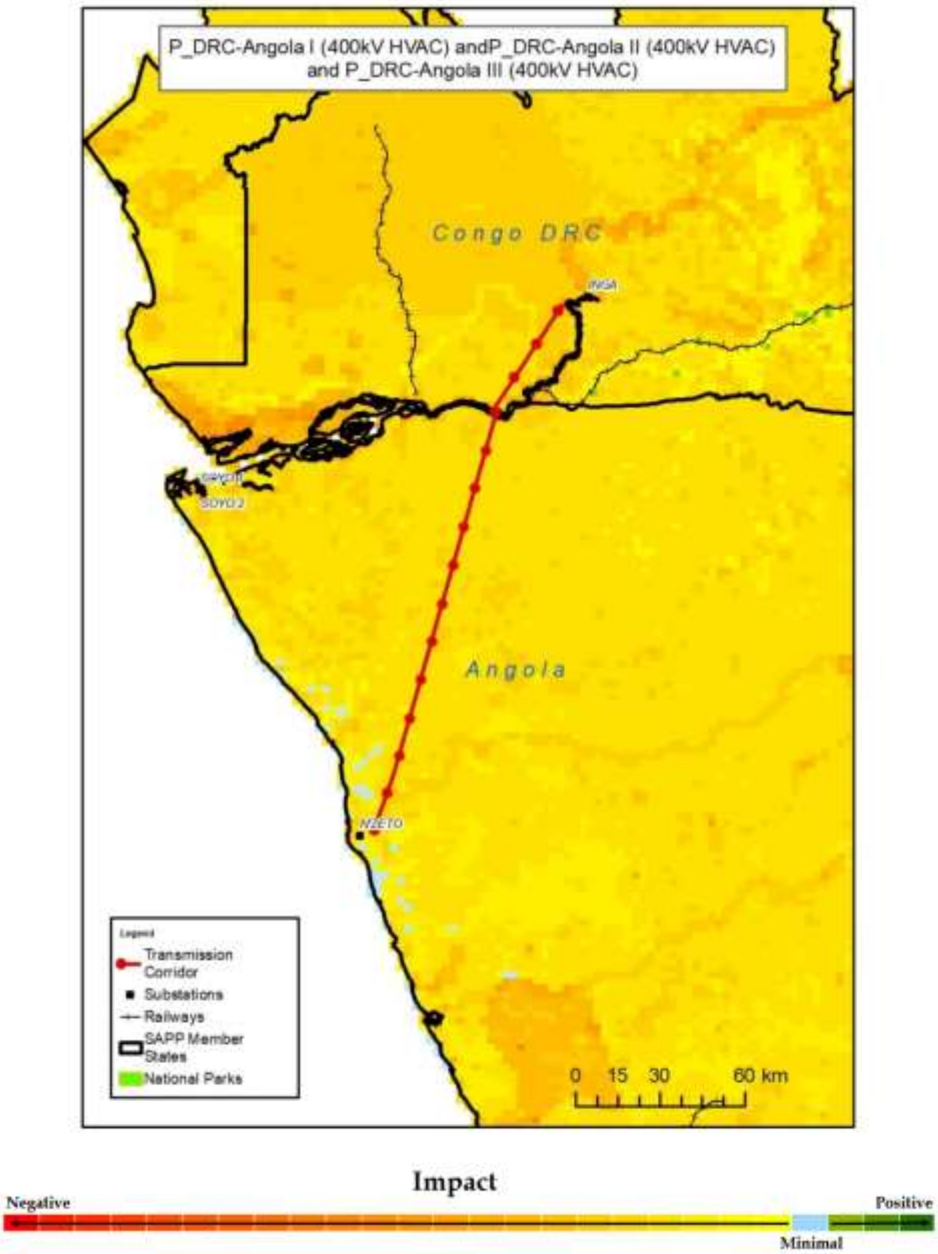


Table 155 GIS Analysis of P_DRC-Angola I, II and III

Number of GRIDS: 274

Sinks

Mines	0
Big Mines (>5 ha)	0
Small Mines (<5 ha)	0
Industrial Areas	0
Commercial Areas	0
Airports	1
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	8
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	24
Wetland	13
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	65
Max Temp (> 30Deg C)	274
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	5
Towns	0
Night Lights	0
Village/Rural Settlmnt	4
Densely Populated	32
Population Estimates	44,236
Commercial Cultivation	23
Development Corridors	6
Development Hubs	1
Potential Development	0

Resources

Coal Resources	0
PV Resources	0
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	102

Land Use

Protected Areas	0
National Parks	0
Cultivation	23
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	89
Wildfires	0
Erosion	256

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	3
Floodplain	201

Constraints

Paved Roads	33
Unpaved Roads	36
Major/Main Roads	24
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	269
Low Vegetation	2
Grasslands	274
Bare Earth	17

Table 156 P_DRC-South Africa I (600kV HVDC) and II (600kV HVDC)

Component A	
Component B	2033
Component C	2032
Voltage (kV)	600 DC
Capacity (MW)	3000
Start	Inga
End	Merensky
Other substations	

Figure 33 Map A of P_DRC-South Africa I and II

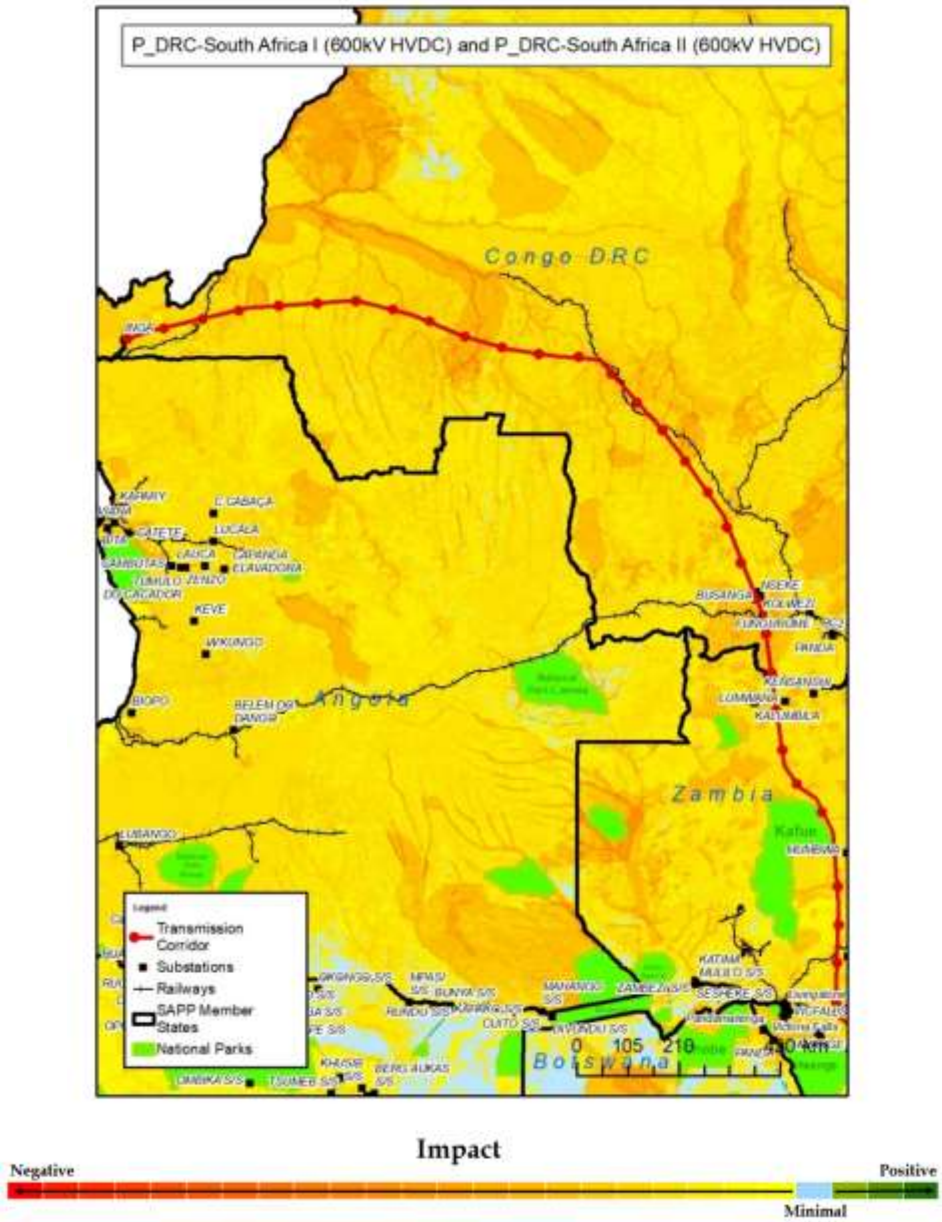


Figure 34 Map B of P_DRC-South Africa I and II

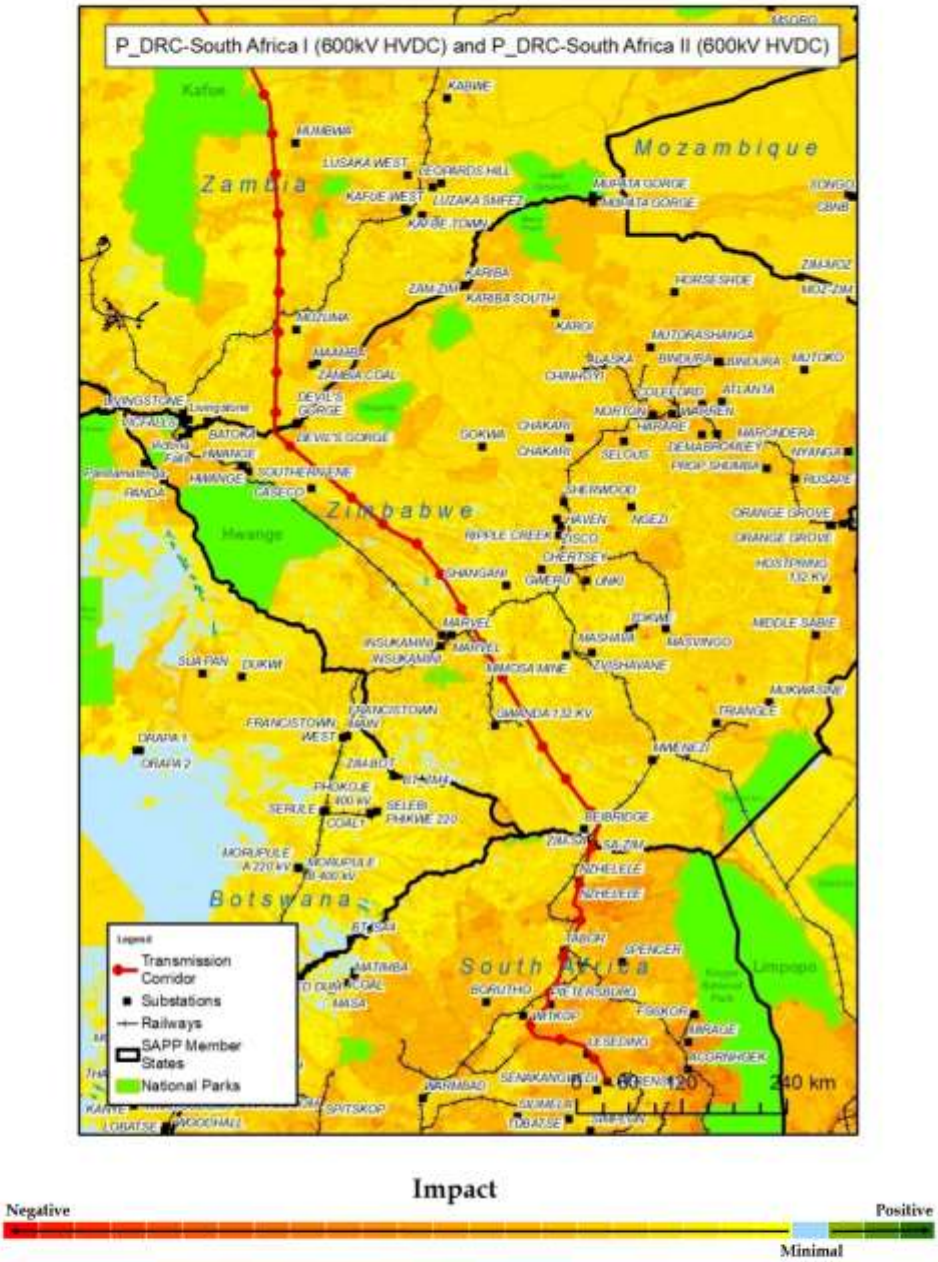


Table 157 GIS Analysis of P_DRC-South Africa I and II

Number of GRIDS: 4,390

Sinks

Mines	185
Big Mines (>5 ha)	102
Small Mines (<5 ha)	91
Industrial Areas	0
Commercial Areas	7
Airports	17
Utilities	5
Harbours	0
Reservoirs	7

Sources

Power Lines (exist)	482
Power Lines (plan)	123
Power Plants (exist)	2
Power Plants (plan)	1
Substations (exist)	4
Substations (plan)	2

Limitations

Water	482
Wetland	316
RAMSAR Sites	0
Important Bird Areas	86
Biodiversity Hotspot	0

Weather

Annual Precipitation	2,676
Max Temp (> 30Deg C)	3,871
Min Temp (<5 Deg C)	681

Sinks

Urban / Builtup Areas	466
Towns	8
Night Lights	66
Village/Rural Settlmnt	234
Densely Populated	356
Population Estimates	1,660,341
Commercial Cultivation	689
Development Corridors	299
Development Hubs	17
Potential Development	0

Resources

Coal Resources	297
PV Resources	698
CSP Resources	203
Wind Resources	128
Undiscovered Oil / Gas	0

Land Use

Protected Areas	431
National Parks	0
Cultivation	689
Historic Areas	11
Tourist Attractions	2
Tribal/Customary Land	194

Hazards

Volcanos	0
Landslides	0
Earthquakes	249
Tropical Storms	96
Lightning	1,974
Wildfires	12
Erosion	3,944

Sinks

Load Centres	12

Commodities

Gold	3
Copper	112
Aluminium	1
Diamonds	0
Uranium	0
Chromium	57
Gemstones	0
Iron Ore	51

Topography

Slope (>30%)	111
Floodplain	2,192

Constraints

Paved Roads	397
Unpaved Roads	2,294
Major/Main Roads	399
Railway Lines	177
Railway Stations	8

Background Info

Tall Bushes / Trees	3,885
Low Vegetation	3,349
Grasslands	3,990
Bare Earth	1,763

Table 158 P_DRC-Zambia I (500kV HVDC) and P_DRC-Zambia II (500kV HVDC)	
Component A	
Component B	2030
Component C	2031
Voltage (kV)	500 DC
Capacity (MW)	2000
Start	Inga
End	Luano
Other substations	

Figure 35 Map of P_DRC-Zambia I and P_DRC-Zambia II

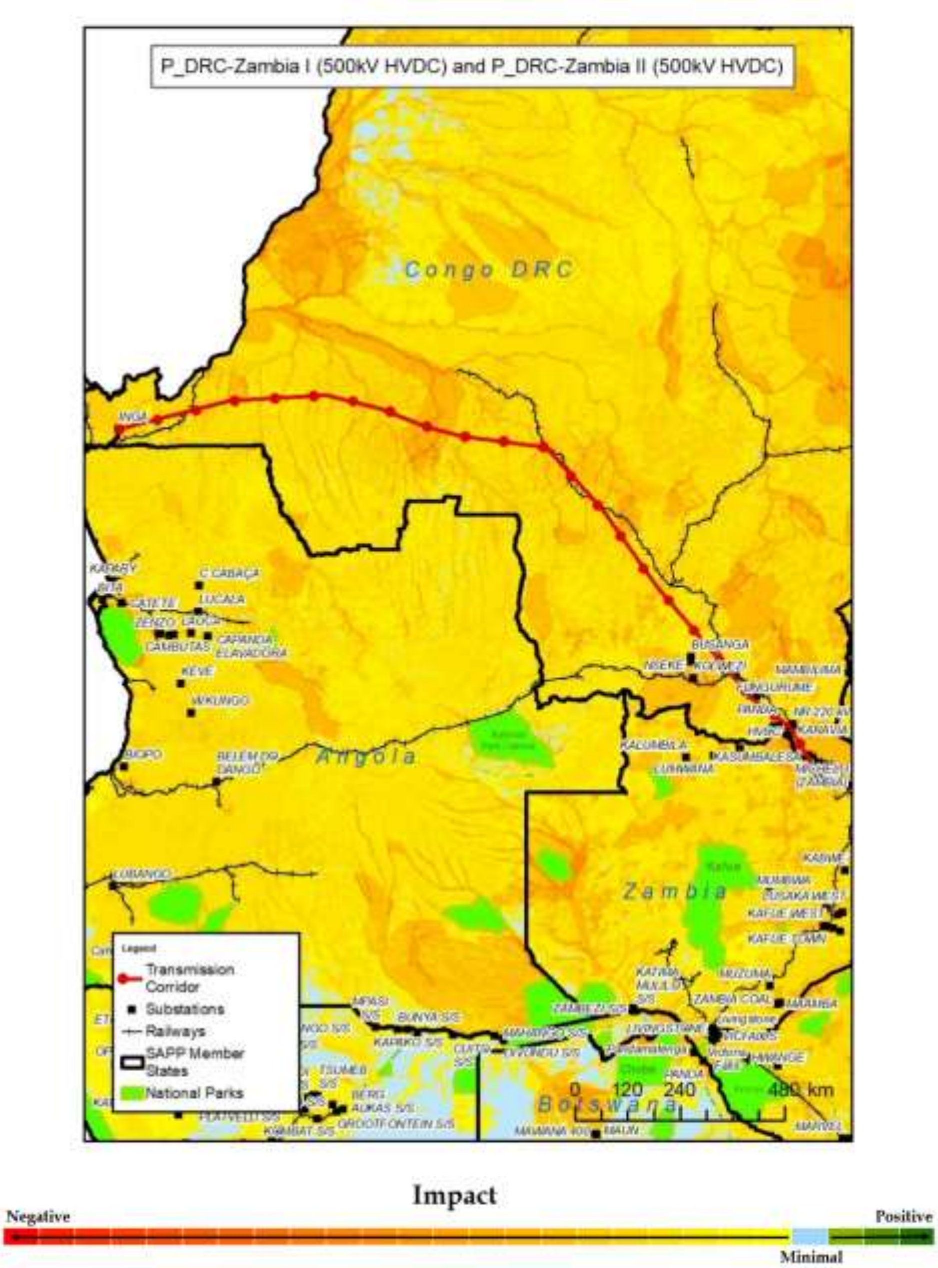


Table 159 GIS Analysis of P_DRC-Zambia I and II

Number of GRIDS: 2,544

Sinks

Mines	74
Big Mines (>5 ha)	67
Small Mines (<5 ha)	14
Industrial Areas	0
Commercial Areas	1
Airports	6
Utilities	7
Harbours	0
Reservoirs	1

Sources

Power Lines (exist)	287
Power Lines (plan)	50
Power Plants (exist)	2
Power Plants (plan)	1
Substations (exist)	0
Substations (plan)	0

Limitations

Water	232
Wetland	225
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	2,544
Max Temp (> 30Deg C)	2,309
Min Temp (<5 Deg C)	62

Sinks

Urban / Builtup Areas	246
Towns	5
Night Lights	42
Village/Rural Settlmnt	122
Densely Populated	299
Population Estimates	1,717,051
Commercial Cultivation	471
Development Corridors	132
Development Hubs	47
Potential Development	0

Resources

Coal Resources	32
PV Resources	215
CSP Resources	0
Wind Resources	0
Undiscovered Oil / Gas	0

Land Use

Protected Areas	187
National Parks	0
Cultivation	471
Historic Areas	2
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	102
Tropical Storms	0
Lightning	1,973
Wildfires	5
Erosion	2,304

Sinks

Load Centres	0

Commodities

Gold	1
Copper	124
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	48
Floodplain	1,746

Constraints

Paved Roads	96
Unpaved Roads	1,040
Major/Main Roads	131
Railway Lines	109
Railway Stations	3

Background Info

Tall Bushes / Trees	2,401
Low Vegetation	1,501
Grasslands	2,209
Bare Earth	980

Table 160 P_Namibia-South Africa II (400kV HVAC)	
Component A	
Component B	
Component C	
Voltage (kV)	400 (AC)
Capacity (MW)	
Start	Obib
End	Aggeneis, Gromis
Other substations	Kudu, Oranjemund

Figure 36 Map of P_Namibia-South Africa II

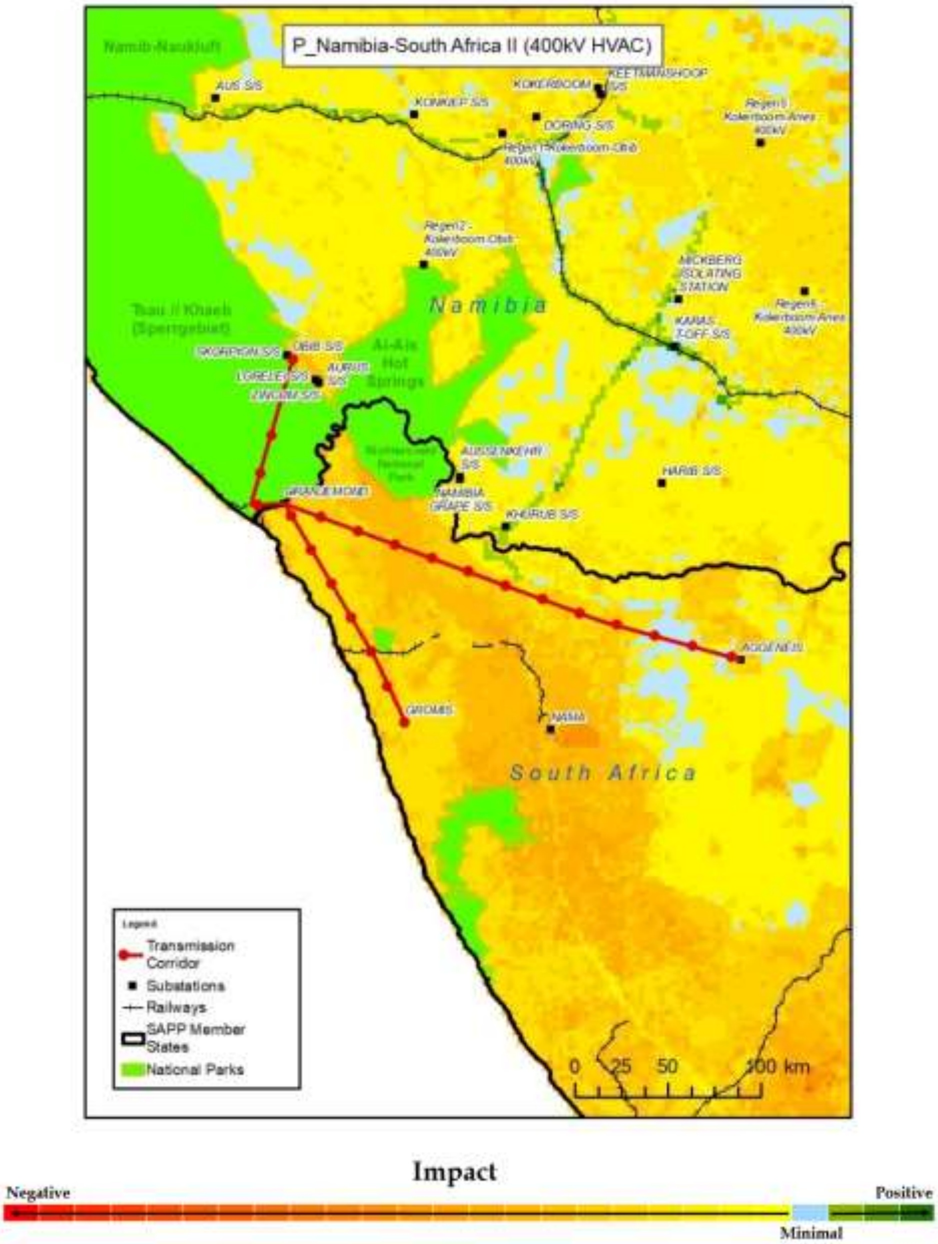


Table 161 GIS Analysis of P_Namibia-South Africa II

Number of GRIDS: 581

Sinks

Mines	73
Big Mines (>5 ha)	38
Small Mines (<5 ha)	41
Industrial Areas	0
Commercial Areas	2
Airports	4
Utilities	2
Harbours	0
Reservoirs	3

Sources

Power Lines (exist)	102
Power Lines (plan)	74
Power Plants (exist)	0
Power Plants (plan)	1
Substations (exist)	5
Substations (plan)	0

Limitations

Water	15
Wetland	2
RAMSAR Sites	3
Important Bird Areas	14
Biodiversity Hotspot	8

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	173
Min Temp (<5 Deg C)	169

Sinks

Urban / Builtup Areas	4
Towns	0
Night Lights	3
Village/Rural Settlmnt	1
Densely Populated	0
Population Estimates	1,994
Commercial Cultivation	4
Development Corridors	7
Development Hubs	0
Potential Development	11

Resources

Coal Resources	0
PV Resources	492
CSP Resources	64
Wind Resources	224
Undiscovered Oil / Gas	1

Land Use

Protected Areas	0
National Parks	115
Cultivation	4
Historic Areas	2
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	44
Lightning	0
Wildfires	0
Erosion	183

Sinks

Load Centres	0

Commodities

Gold	0
Copper	11
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	41
Floodplain	12

Constraints

Paved Roads	35
Unpaved Roads	298
Major/Main Roads	39
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	102
Low Vegetation	513
Grasslands	512
Bare Earth	442

A4.2 Power Generation Facilities

The regional power generation facilities have been screened relative to their context and potential for significant impact if developed and the results appear in Figure 37. The screening process considers plant location in the assessment; however, the different types of generation will result in differing profiles at a project level. Hydropower generation facilities may have extensive downstream and reservoir impacts whilst thermal generation facilities may have more localized direct impacts but diffuse impacts in relation to GHGs etc.

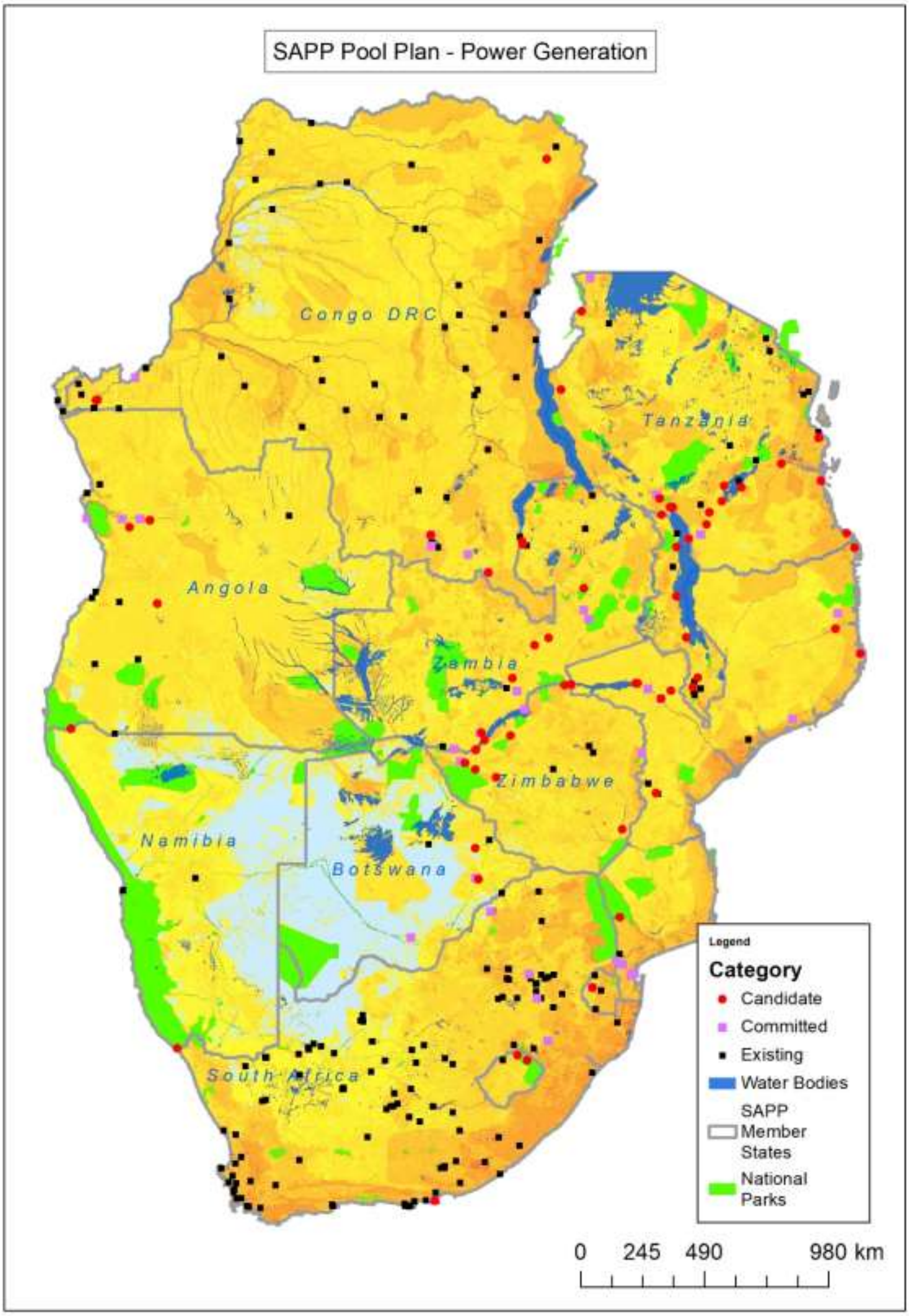
As for the transmission lines, National Parks have been defined as no-go areas and used to largely screen out projects affecting these areas at this level.(see Annex 1 for Mupata Gorge HPP example). As can be seen from Table 162, only 3 generation facilities appear to be inside National Park boundaries. However, the location information for these has been derived from open-source data thus there may be an accuracy issue that can be redressed by the owners of these facilities.

Table 162 Generation projects in National Parks

Country	Name	Capacity	Technology	Status
Angola	Caculo Cabaça	2,160 MW	Hydro	Committed
Lesotho	Letseng wind	65 MW	Renewable	Candidate
Zambia	Mambilimba Falls	326 MW	Hydro	Candidate

Source: National power sector master plans

Figure 37 Map of regional power generation facilities



A4.3 Conclusions

A pre-requisite for the GIS-based approach to be successful is the establishment of a reliable, representative and current database of both spatial and associated non-spatial attribute information. This is a key necessity to establish both location and thematic map data in order to create a functional GIS platform for analysis and impact assessment.

The GIS database established now contains spatial information of the main primary energy sources, developmental "no-go" areas (currently defined as National Parks), thematic environmental and social data and planned regional generation and transmission infrastructure. The GIS database forms the basis of the RIAM assessment which indicates environmental sensitivity and linked to that the potential significance of impacts associated with development.

The outcome of the preliminary screening process shows that:

- As a result of an iterative process to define transmission line corridors none of the proposed routes directly impacts on a no-go area
- Direct impacts associated with generation facilities do not affect no-go areas except possibly in 3 cases

It is anticipated, therefore, that from a preliminary planning perspective there are no constraints to development with the scenarios proposed. However, screening will be followed by more detailed environmental and social studies at a project level which could potentially change the picture and projects such as Stiegler's Gorge HPP in Tanzania which may pass initial screening could be ruled out at a later date.

To minimize the risk of controversial projects passing initial screening it is recommended that SAPP continue to develop the GIS database with the ambition to increase the scale of resolution to reduce the uncertainties introduced by data deficiency.

A5 Mupata Gorge screening using RIAM

A5.1 Introduction

To demonstrate the use of the GIS and RIAM tools in providing inputs into the SAPP decision making process, the Mupata Gorge Dam was identified as an ideal case study, as the proposed dam would influence the Mana Pools National Park amongst numerous other impacts. Refer to Figure 38 for an overview map of the Zambezi river from Lake Kariba to the Mupata Gorge dam.

Figure 38 Zambezi river from Lake Kariba to the proposed Mupata Gorge dam site

As the proposed dam development would dramatically impact protected areas in both Zambia and Zimbabwe, the dam has been seen as controversial, from a conservation perspective, since its proposed development. To be able to make informed decisions on projects from an engineering, financial feasibility as well as an environmental and socio-economic perspective, appropriate data needs to be provided and analysed.

With respect to the environmental and socio-economic perspectives, the Rapid Impacts Assessment Matrix tool (RIAM) is used to analyse the following three major components based on the data collected and collated within the GIS environment:

- Physical and Chemical
- Biological and Ecological
- Socio-Economic and Cultural

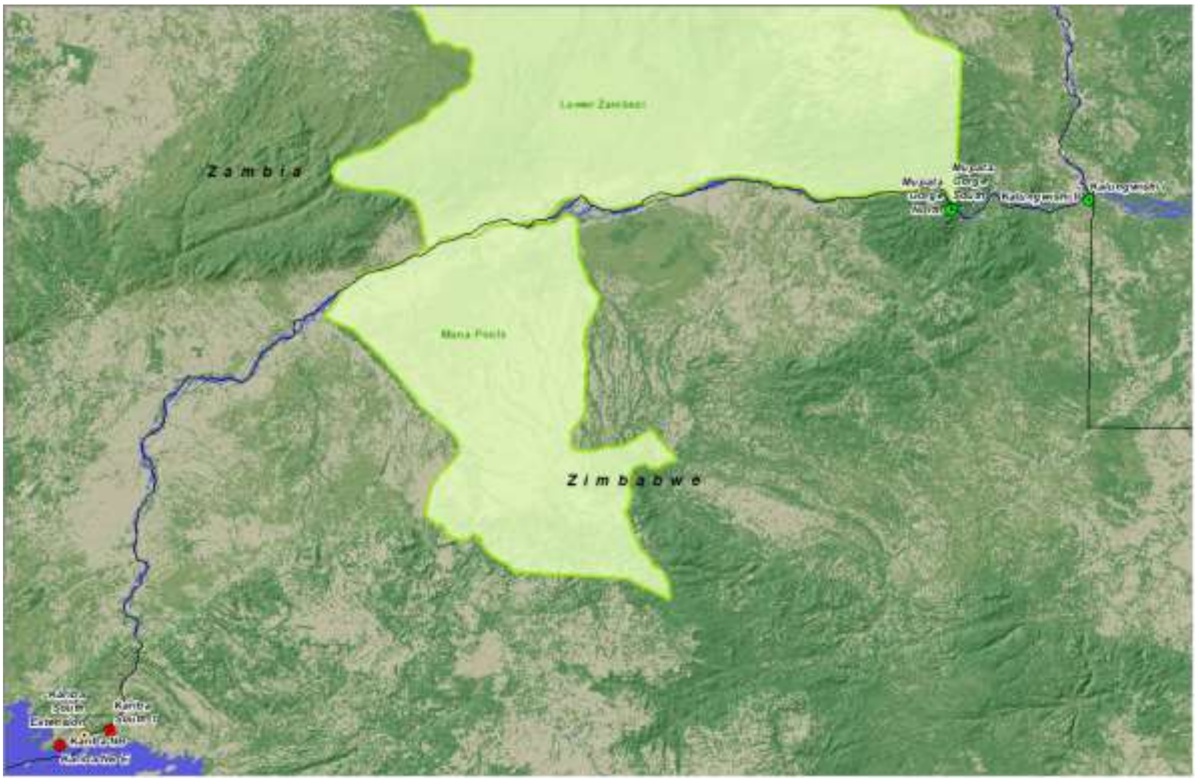
Using the GIS spatial data repository as compiled within the 2.5km by 2.5km GRID, it is possible to utilize the data for the proposed dam site to illustrate the impact of the water body on the immediate as well as the surrounding areas using the above-mentioned factors and their associated range value scores as extracted from the RIAM analysis and translated to an environmental sensitivity map.

Figure 39 illustrates the various protected areas along the Zambezi river between Lake Kariba and the Mupata Gorge dam wall site.

Figure 39 Protected areas on the Zambezi river from Lake Kariba to Mupata Gorge dam

Figure 40 illustrates the National Parks along the Zambezi river between Lake Kariba and the Mupata Gorge dam wall site.

Figure 40 National Park on the Zambezi river from Lake Kariba to the Mupata Gorge dam



A5.2 Mupata Gorge Dam extent modelling

Due to limited information available on the Mupata Gorge dam development, the proposed dam wall was located and a theoretical dam wall height of 370m above mean sea level (AMSL) was chosen to define the potential extent of the dam on its completion.

This theoretical modelling exercise was based on the Shuttle Radar Topographic Mission (SRTM) 90m digital elevation model data as sourced from the United States Geological Survey (USGS).The digital elevation model of DEM was “flooded” to provide an indication of the extent of the water body if a 370m (AMSL) high dam wall was built. This modelling exercise resulted in a water body (Mupata Gorge Dam) as illustrated in Figure 41.

Figure 41 Theoretical extent of Mupata Gorge Dam if 370m high (AMSL) dam wall built

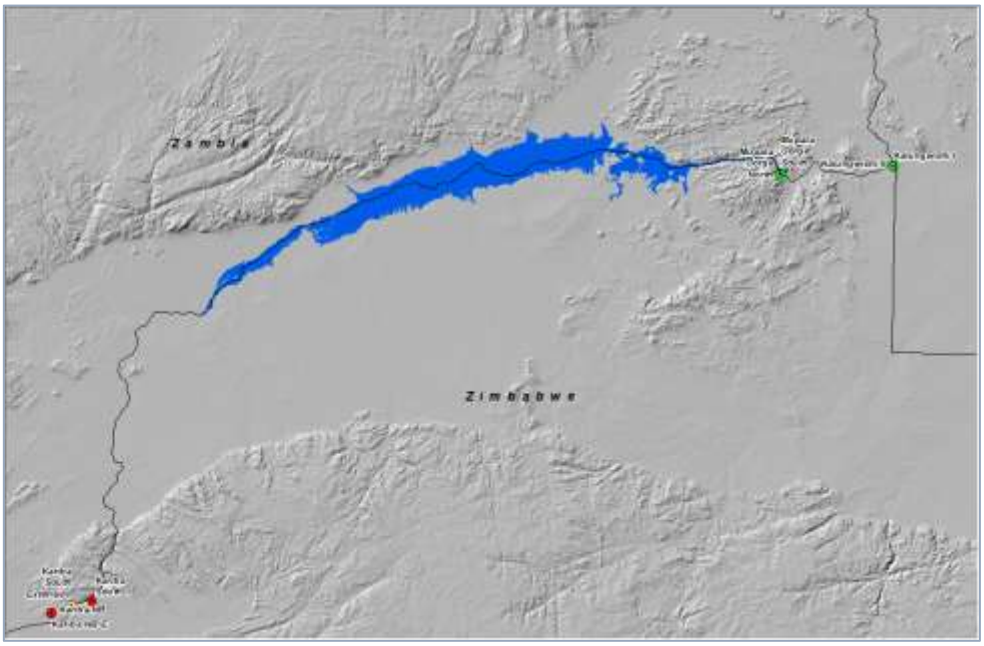


Figure 42 illustrates the extent of the dam in context of the protected areas along the Zambesi River.

Figure 42 Theoretical extent of the Mupata Gorge Dam in relation to the protected areas

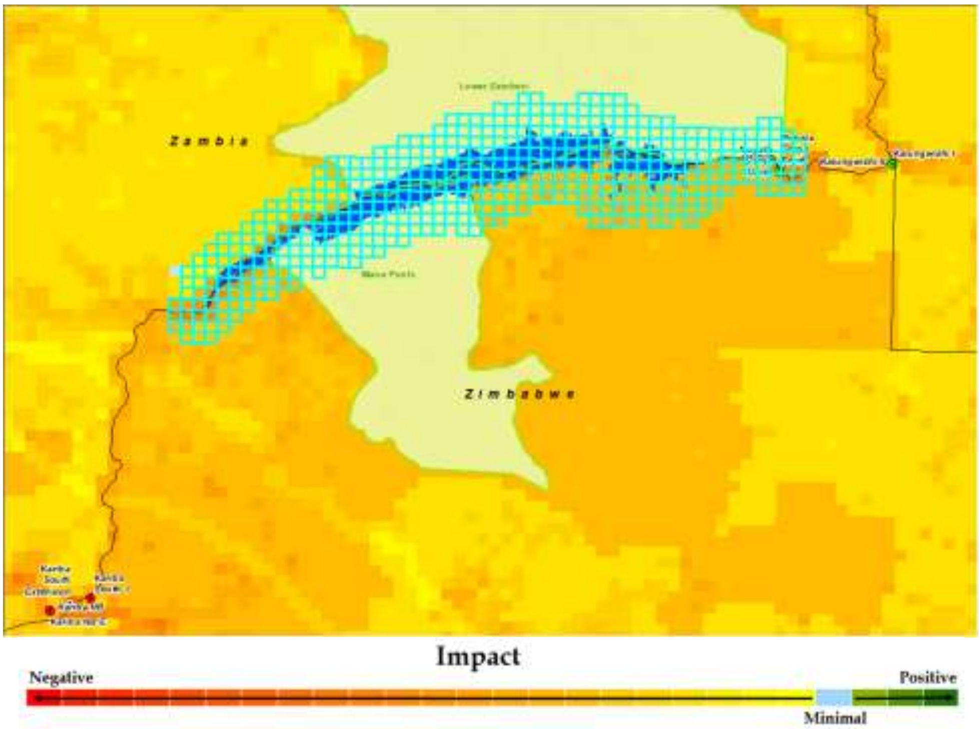
A5.3 Screening of Impacts of the proposed dam

The GIS and RIAM datasets developed as part of this project provide a consistent and complete overview of the SAPP region (12 countries) and rely heavily on open source datasets compiled as part of this project. The data is mapped and represented at a regional or national scale, however, the GIS and RIAM tools are scalable and higher resolution data when available can allow for project scale reporting or mapping.

For the purposes of this case study we are using the regional/national data to illustrate the use of the RIAM tools which could be refined in future through the provision of detailed project level data if required.

To define the geographic extent of the impact of the proposed dam development, a 5km buffer was created around the dam and this was intersected with the GIS grid (2.5km by 2.5km). A total of 470 grid cells representing 2,937.5 km² were selected as illustrated in Figure 43.

Figure 43 Impact of the dam development



Illustrated through a 5km buffer of the theoretical dam extent overlaid on the RIAM Sensitivity GRID

The information compiled as part of the GIS data repository was summarized to provide an overview of the various grid values for the GIS data categories across the 470 cells.

In Table 163 (Zambia), Table 164 (Zambia/Zimbabwe border), Table 165 (Zimbabwe) and Table 166 (Full project area), the GIS tools have summarized the impact of the dam development in terms of spatial datasets integrated within the SAPP GRID.

Table 163 Values of grid cells impacted by buffer around the dam development in Zambia

Number of GRIDS: 188

Sinks

Mines	1
Big Mines (>5 ha)	1
Small Mines (<5 ha)	0
Industrial Areas	0
Commercial Areas	0
Airports	0
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	0
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	35
Wetland	18
RAMSAR Sites	0
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	188
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	5
Towns	0
Night Lights	0
Village/Rural Settlmnt	1
Densely Populated	2
Population Estimates	3,260
Commercial Cultivation	1
Development Corridors	0
Development Hubs	0
Potential Development	0

Resources

Coal Resources	21
PV Resources	0
CSP Resources	0
Wind Resources	0

Land Use

Protected Areas	143
National Parks	143
Cultivation	1
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	0
Wildfires	0
Erosion	188

Sinks

Load Centres	1

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	58
Floodplain	32

Constraints

Paved Roads	0
Unpaved Roads	36
Major/Main Roads	3
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	181
Low Vegetation	188
Grasslands	184
Bare Earth	48

Table 164 Values of grid cells impacted by buffer around dam dev. in Zambia/Zimbabwe

Number of GRIDS: 79

Sinks

Mines	0
Big Mines (>5 ha)	0
Small Mines (<5 ha)	0
Industrial Areas	0
Commercial Areas	0
Airports	1
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	0
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	79
Wetland	76
RAMSAR Sites	24
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	79
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	1
Towns	0
Night Lights	0
Village/Rural Settlmnt	3
Densely Populated	0
Population Estimates	513
Commercial Cultivation	0
Development Corridors	0
Development Hubs	0
Potential Development	0

Resources

Coal Resources	13
PV Resources	0
CSP Resources	0
Wind Resources	0

Land Use

Protected Areas	77
National Parks	65
Cultivation	0
Historic Areas	0
Tourist Attractions	0
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	0
Wildfires	0
Erosion	79

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	12
Floodplain	71

Constraints

Paved Roads	0
Unpaved Roads	41
Major/Main Roads	0
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	79
Low Vegetation	79
Grasslands	79
Bare Earth	74

Table 165 Values of grid cells impacted by buffer around dam development in Zimbabwe

Number of GRIDS: 203

Sinks

Mines	0
Big Mines (>5 ha)	0
Small Mines (<5 ha)	0
Industrial Areas	0
Commercial Areas	0
Airports	4
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	0
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	28
Wetland	12
RAMSAR Sites	77
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	203
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	2
Towns	0
Night Lights	0
Village/Rural Settlmnt	1
Densely Populated	0
Population Estimates	157
Commercial Cultivation	0
Development Corridors	0
Development Hubs	0
Potential Development	0

Resources

Coal Resources	124
PV Resources	0
CSP Resources	0
Wind Resources	0

Land Use

Protected Areas	203
National Parks	179
Cultivation	0
Historic Areas	0
Tourist Attractions	1
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	0
Wildfires	0
Erosion	176

Sinks

Load Centres	0

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	18
Floodplain	18

Constraints

Paved Roads	0
Unpaved Roads	103
Major/Main Roads	1
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	199
Low Vegetation	203
Grasslands	195
Bare Earth	24

Table 166 Values of grid cells impacted by buffer around dam development

Number of GRIDS: 470

Sinks

Mines	1
Big Mines (>5 ha)	1
Small Mines (<5 ha)	0
Industrial Areas	0
Commercial Areas	0
Airports	5
Utilities	0
Harbours	0
Reservoirs	0

Sources

Power Lines (exist)	0
Power Lines (plan)	0
Power Plants (exist)	0
Power Plants (plan)	0
Substations (exist)	0
Substations (plan)	0

Limitations

Water	142
Wetland	106
RAMSAR Sites	101
Important Bird Areas	0
Biodiversity Hotspot	0

Weather

Annual Precipitation	0
Max Temp (> 30Deg C)	470
Min Temp (<5 Deg C)	0

Sinks

Urban / Builtup Areas	8
Towns	0
Night Lights	0
Village/Rural Settlmnt	5
Densely Populated	2
Population Estimates	3,930
Commercial Cultivation	1
Development Corridors	0
Development Hubs	0
Potential Development	0

Resources

Coal Resources	158
PV Resources	0
CSP Resources	0
Wind Resources	0

Land Use

Protected Areas	423
National Parks	387
Cultivation	1
Historic Areas	0
Tourist Attractions	1
Tribal/Customary Land	0

Hazards

Volcanos	0
Landslides	0
Earthquakes	0
Tropical Storms	0
Lightning	0
Wildfires	0
Erosion	443

Sinks

Load Centres	1

Commodities

Gold	0
Copper	0
Aluminium	0
Diamonds	0
Uranium	0
Chromium	0
Gemstones	0
Iron Ore	0

Topography

Slope (>30%)	88
Floodplain	121

Constraints

Paved Roads	0
Unpaved Roads	180
Major/Main Roads	4
Railway Lines	0
Railway Stations	0

Background Info

Tall Bushes / Trees	459
Low Vegetation	470
Grasslands	458
Bare Earth	146

Table 167 illustrates the significant components as identified by the GIS tools when analyzing and quantifying the impact of the Mupata Gorge Dam development:

Table 167 Summary of significant components as identified by the GIS analysis

	Zambia	Border area	Zimbabwe	Total
Number of GRID cells	188	79	203	470
Population	3,260	513	157	3,930
Densely populated areas	2	0	0	2
Urban / Built up areas	5	1	2	8
Wetlands	18	76	23	106
RAMSAR Sites	0	24	77	101
Protected Areas*	143	77	203	423
National Parks*	143	65	179	387
Historical/Cultural	0	0	0	0
Tourist Attractions	0	0	1	1

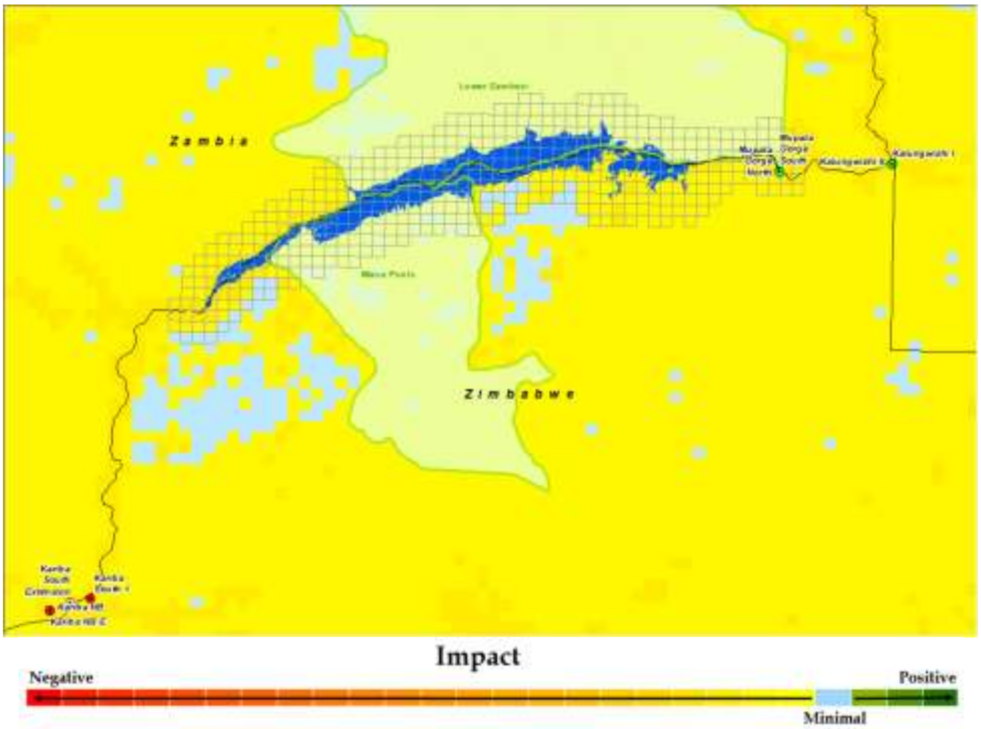
** There is a level of duplication as National Parks are also classified as Protected Areas*

A5.4 Analysing the proposed dam using the RIAM tools and the derived sensitivity maps

The 470 grid cells selected within 5km of the modelled Mupata Gorge Dam development were then analysed in terms of the RIAM derived sensitivity maps to provide inputs into the decision-making process.

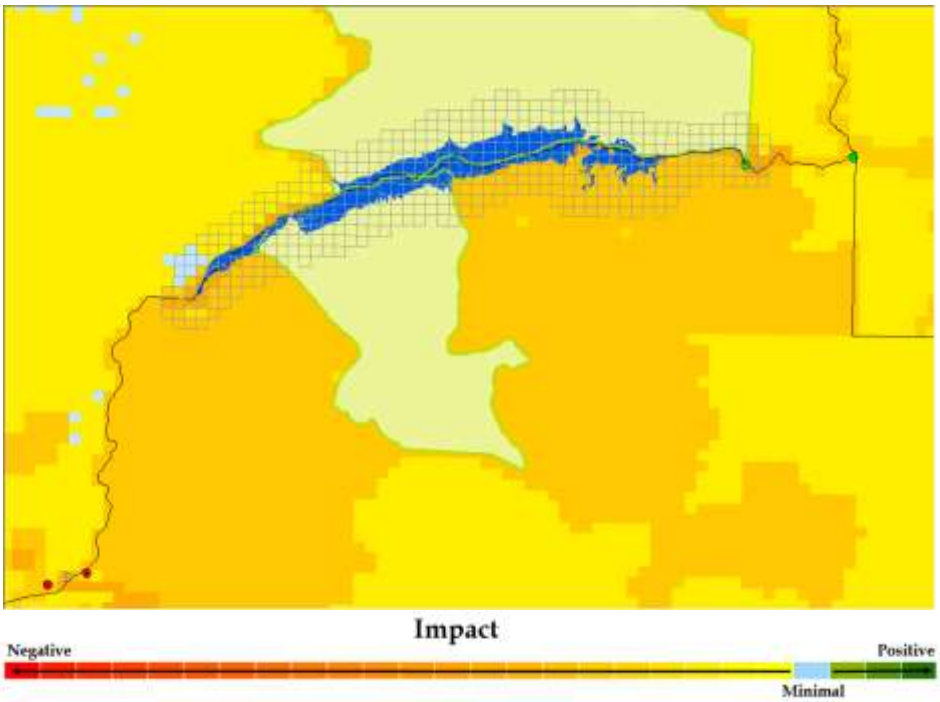
Refer to Figure 44 for a map of the Physical/Chemical impacts as reflected in the RIAM derived sensitivity map.

Figure 44 RIAM derived Physical/Chemical Impacts around proposed Dam development



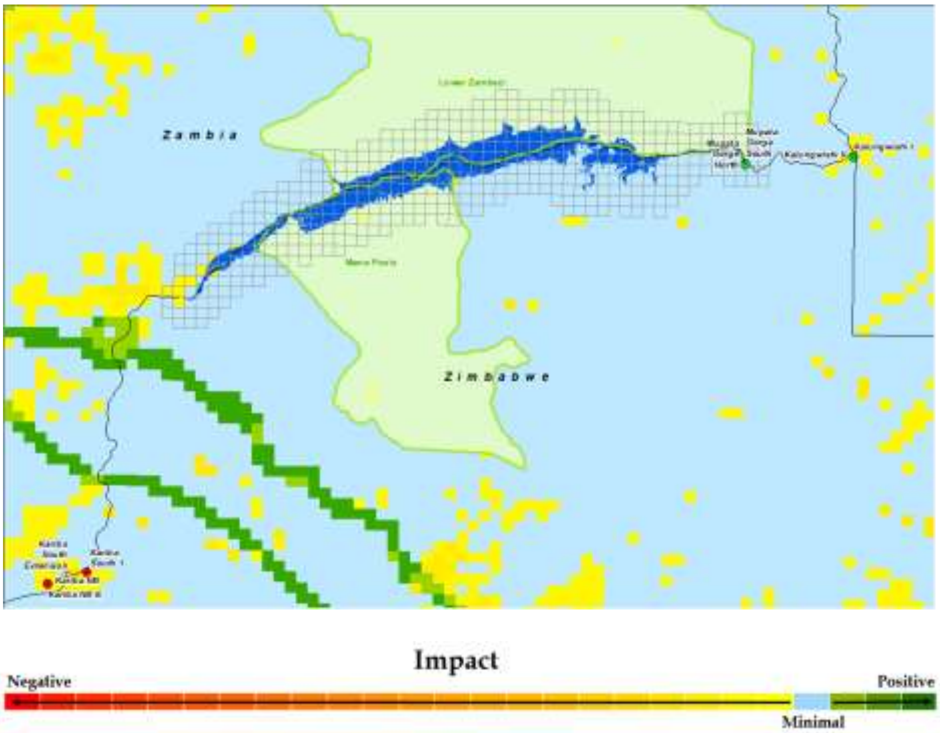
Refer to Figure 45 for a map of the Biological/Ecological impacts as reflected in the RIAM derived sensitivity map.

Figure 45 RIAM derived Bio/Ecological Impacts around proposed Dam development



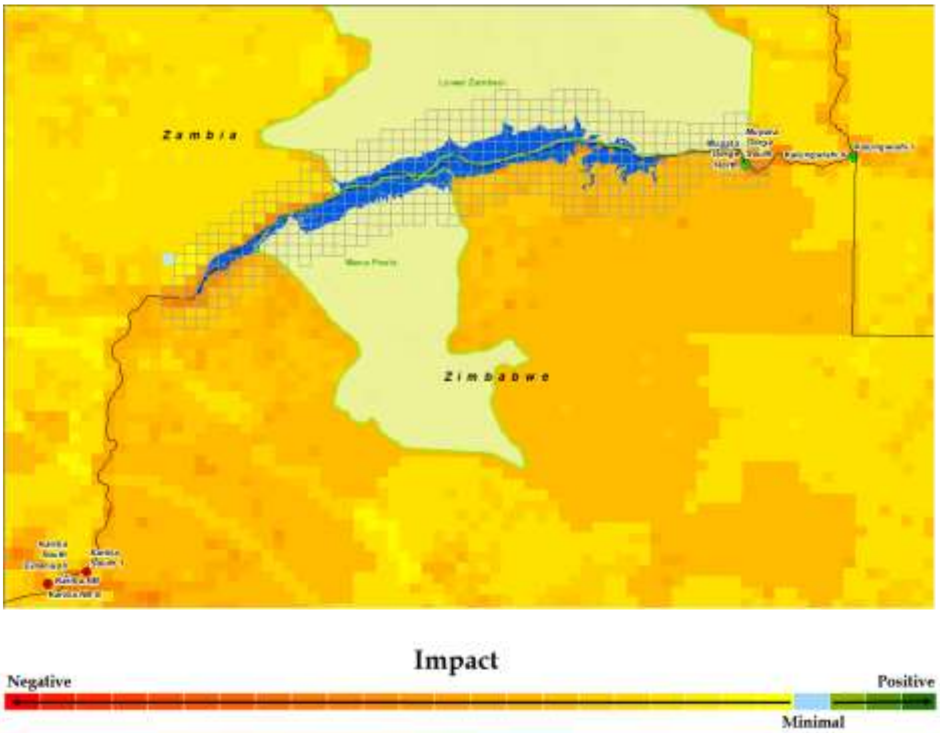
Refer to Figure 46 for a map of the Socio-ecological/Cultural impacts as reflected in the RIAM derived sensitivity map.

Figure 46 RIAM derived Socio/Cultural Impacts around proposed Dam development.



Refer to Figure 47 for a map of the combined impacts as reflected in the RIAM derived sensitivity map.

Figure 47 Combined RIAM derived Impacts around the proposed Dam development



A5.5 Output and Conclusion

The GIS and RIAM analysis as illustrated in Figure 44 to Figure 47 show limited impacts on the physical/chemical and socio-economic/cultural components but significant impact on the biological/ecological component.

The analysis is dependent on the level of resolution and type of data in the GIS database. In this case for example it is not possible to analyse any potential resettlement impacts or effects on livelihood which may change the socio-economic/cultural impact assessment entirely. However, from an environmental and social screening perspective the data does support a conclusion that due to significant impacts on the biological/ecological component the development of the Mupata Gorge project would be problematic.

In addition, in the application of the GIS at this time National Parks are treated as no-go areas for development given the likelihood of high biodiversity and/or presence of species of conservation value as well as the legal/administrative issues surrounding a gazetted area.

Overall, given the significant impacts to the biological/ecological component and the location of the Mupata Gorge project in a National Park the GIS and RIAM analysis would screen out this project as a potential generation candidate in the scenarios being considered.

A6 Input files for Transmission Modelling

A number of computer models have been received for the modelling of the transmission grid within SAPP. These includes files from SAPP CC and from the national utilities as listed in the following (all files are PSS/E models except files named 'nnn.pfd' or 'nnn.dz' which are DigSilent models):

From	Received	File Name
SAPP CC	March 2016	SAPP 2016 Peak Case.raw
		SAPP 2016 Peak Case.sav
		2015 SAPP DYNAMIC DATA UPDATE DEC 2015.dyr
Angola	August 2016	RNT_2016_r3.sav & RNT_2016_r3.sld
		RNT_2017_r10.sav & RNT_2017_r5.sld
	December 2016	RNT_2017_r10.sav
		RNT_2020.sav
		RNT_2025_5.sav
Botswana	April 2016	NWTGC_Base case 2015 Peak_ok.sav
		NWTGC_Basecase 2015 Light_ok.sav
		NWTGC_2019 Peak_N-S_ok_Final.sav
		NWTGC_2019 Light_N-S_ok_Final.sav
		NWTGC_2025 Peak_N-S_ok_Final.sav
		NWTGC_2025 Light_N-S_ok_Final.sav
		Northwest 2015 Peak dynamic data_Final version.dyr
		Northwest 2015 Light dynamic data_Final version.dyr
		Northwest 2019 dynamic data_Peak_Final version.dyr
		Northwest 2019 dynamic data_Light_Final version.dyr
		Northwest 2025 dynamic data_Peak_Final version.dyr
		Northwest 2025 dynamic data_Light_Final version.dyr
DRC	-	Used the model for Katanga provided by SAPP CC
Lesotho	August 2016	Lesotho 2019_v32.sav
		Lesotho v32.sld

	April 2016	July 2015.dz
Malawi	April 2016	Escom 2016.pfd
Mozambique	April 2016	EDM_Peak_load.sav & EDM_Peak_load.sld EDM_Dynamics.dyr (Above files representing base case 2015) National Peak Load – 2021.sav National Peak Load – 2026.sav EdM South 2021 mod.sld EdM Central2026 – mod.sld
Namibia	August 2016	SAPP_2017Peak_ZZBN2_ZE300_C300_N100_SE0_GerOmbAusIN_KuduIN_Zesco+BPC_04-04-2013_(17 14).sav
	September 2016	NamPower Model 2016-03 rev 0.pfd
South Africa	April 2016	2015TDP-2015CF- Post Peak_Final.sav 2015TDP-2016CF- Post Peak_Final.sav 2015TDP-2017CF- Post Peak_Final.sav 2015TDP-2018CF- Post Peak_Final.sav 2015TDP-2019CF- Post Peak_Final.sav 2015TDP-2020CF- Post Peak_Final.sav 2015TDP-2021CF- Post Peak_Final.sav 2015TDP-2022CF- Post Peak_Final.sav 2015TDP-2023CF- Post Peak_Final.sav 2015TDP-2024CF- Post Peak_Final.sav 2015TDP-2025CF- Post Peak_Final.sav
	December 2016	2016TDP-2016CF- Post Peak_Rev.sav 2016TDP-2017CF- PRE Peak_Rev.sav 2016TDP-2018CF- PRE Peak_Rev.sav 2016TDP-2019CF- PRE Peak_Rev.sav 2016TDP-2020CF- PRE Peak_Rev.sav

		2016TDP-2021CF- PRE Peak_Rev.sav
		2016TDP-2022CF- PRE Peak_Rev.sav
		2016TDP-2023CF- PRE Peak_Rev.sav
		2016TDP-2024CF- PRE Peak_Rev.sav
		2016TDP-2025CF- Pre Peak_Final.sav
		2016TDP-2026CF- PRE Peak_Rev.sav
Swaziland	April 2016	SEC TRANSMISSION PSSE CASEFILE.sav
		SAPP 2015CF Peak-NamPower-4DEC15 0903_SEC split in two.sav
		SEC 04DEC 2.sld
		SEC 07 JAN.sld
	May 2016	2018 SEC Transmission Network Peak Case File.sav
		2018 SEC Transmission Network Peak Case File.sld
Tanzania	June 2016	2015-Base.sav & 2015-Base.sld
		2020 TANESCO.sav & 2020 TANESCO.SLD
Zambia	June 2016	SAPP 2016CF Peak 130416 0946 Eskom-ZESA-ZESCO-CEC PV 3 units Kariba.sav
Zimbabwe	April 2016	SAPP 2016CF Peak 31122015 ver32.sav
		2015 SAPP DYNAMIC DATA UPDATE DEC 2015 With ZESA Update.dyr
	May 2016	ZESA CASE FILE 2016.raw & ZESA 2016 Case File.sld
		ZESA CASE FILE 2020.raw & ZESA 2020 Case File.sld
		ZESA CASE FILE 2025.raw & ZESA 2025 Case File.sld
		ZESA CASE FILE 2030.raw & ZESA 2030 Case File .sld

A7 Overview of power flow on interconnectors

The following figures provides an overview of key interconnectors included in Components A to C.

Figure 48 Stage 2020 – Component A

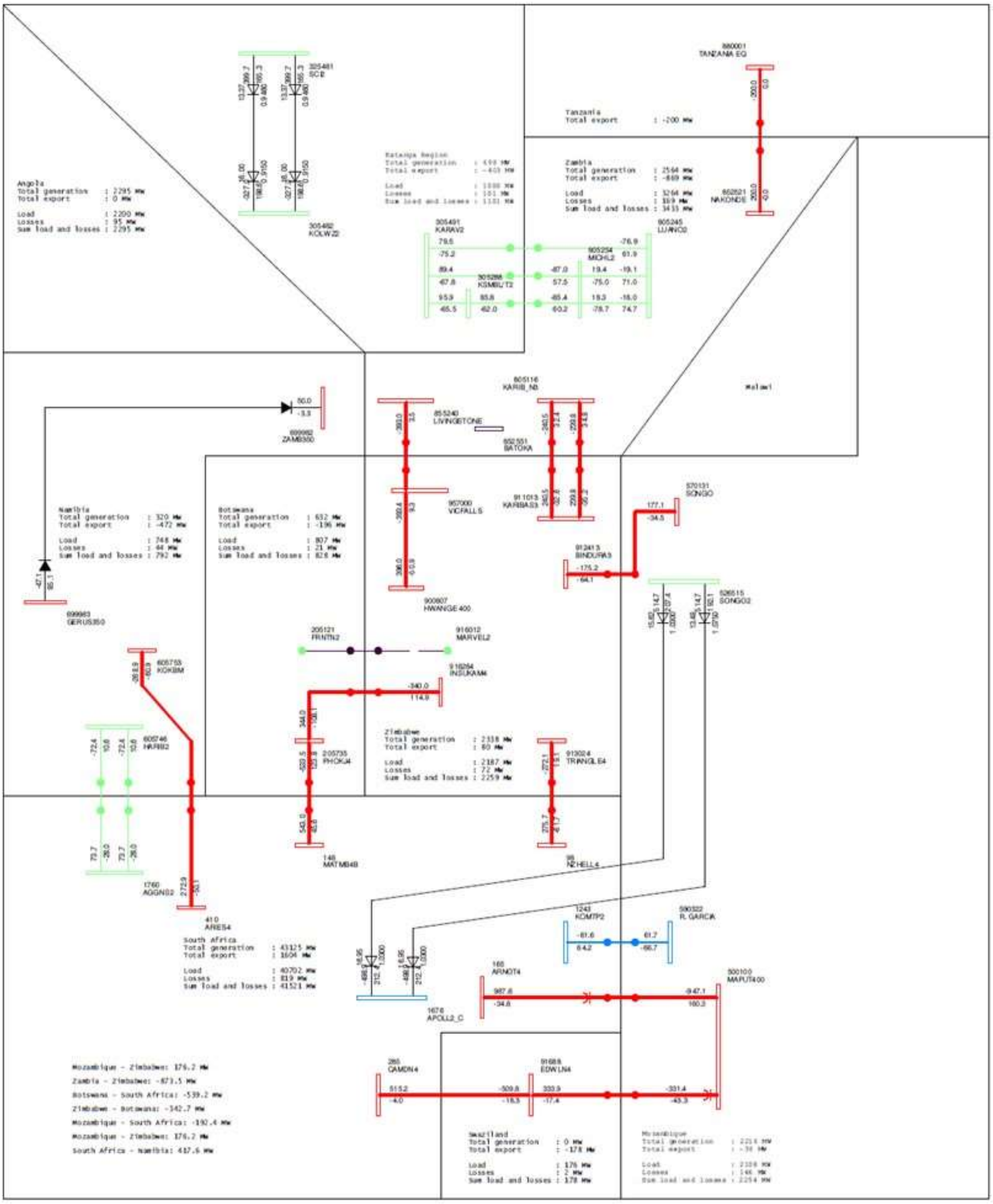


Figure 49 Stage 2025 – Component A

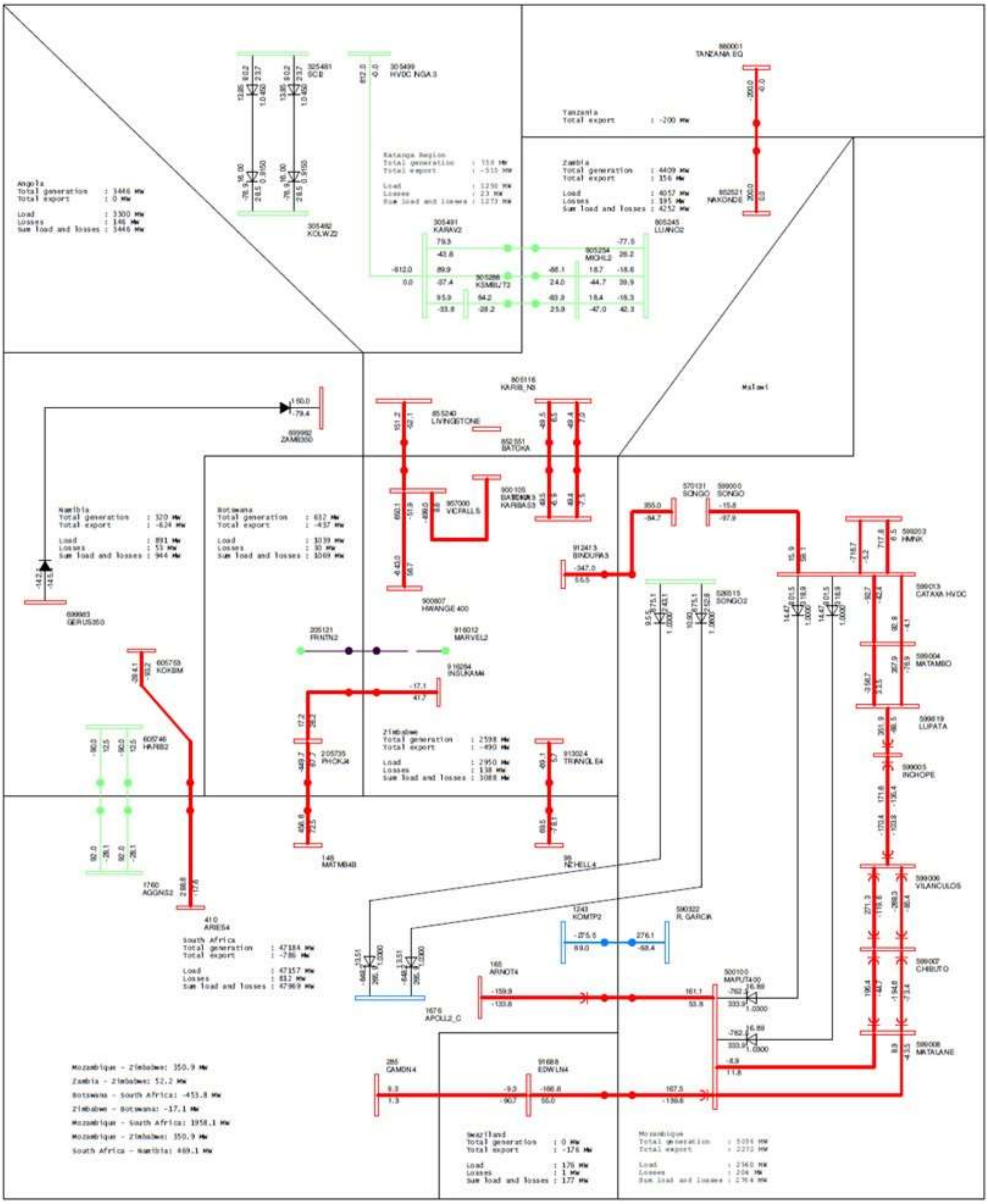


Figure 50 Stage 2030 – Component A

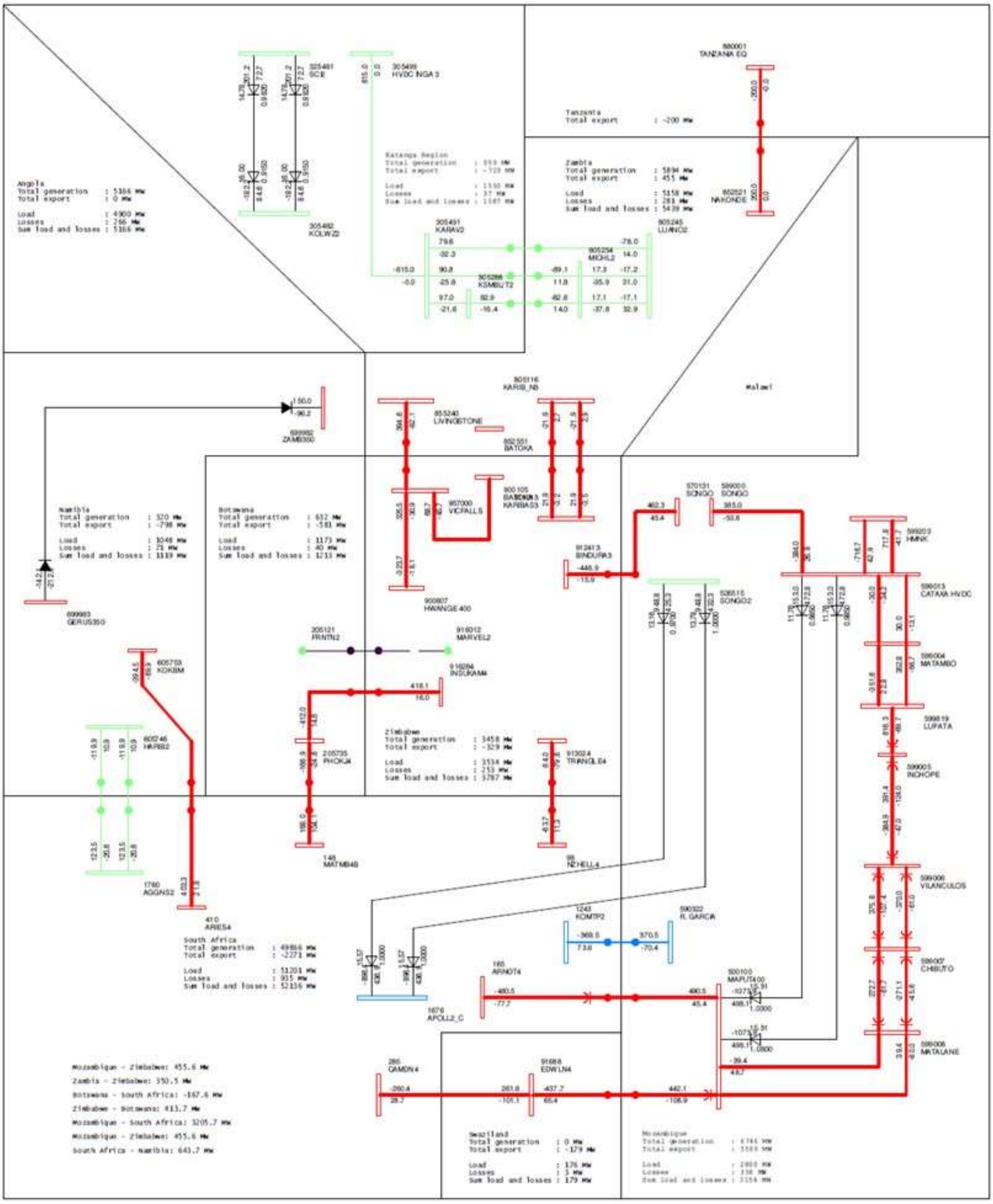


Figure 51 Stage 2020 – Component B

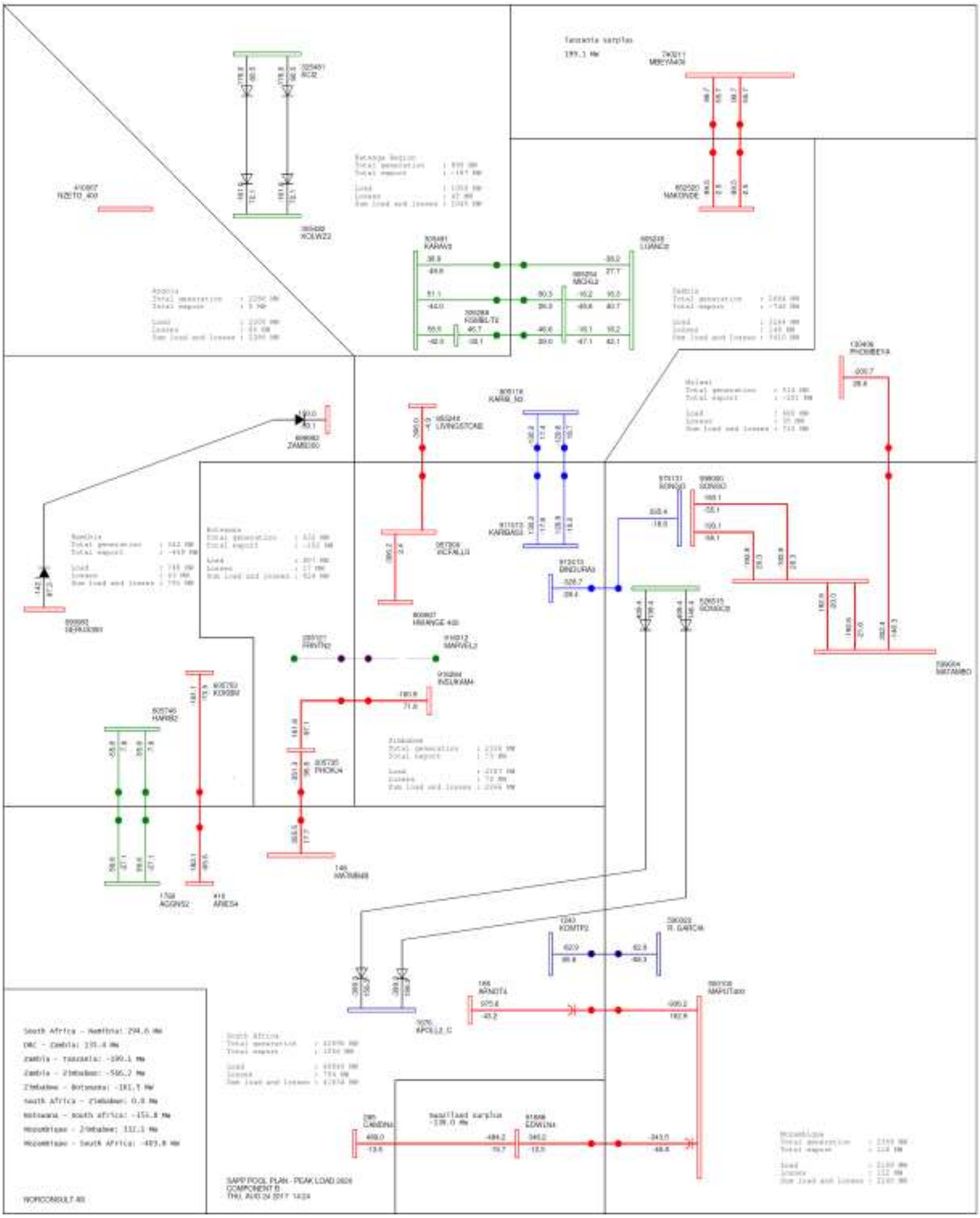


Figure 52 Stage 2025 – Component B

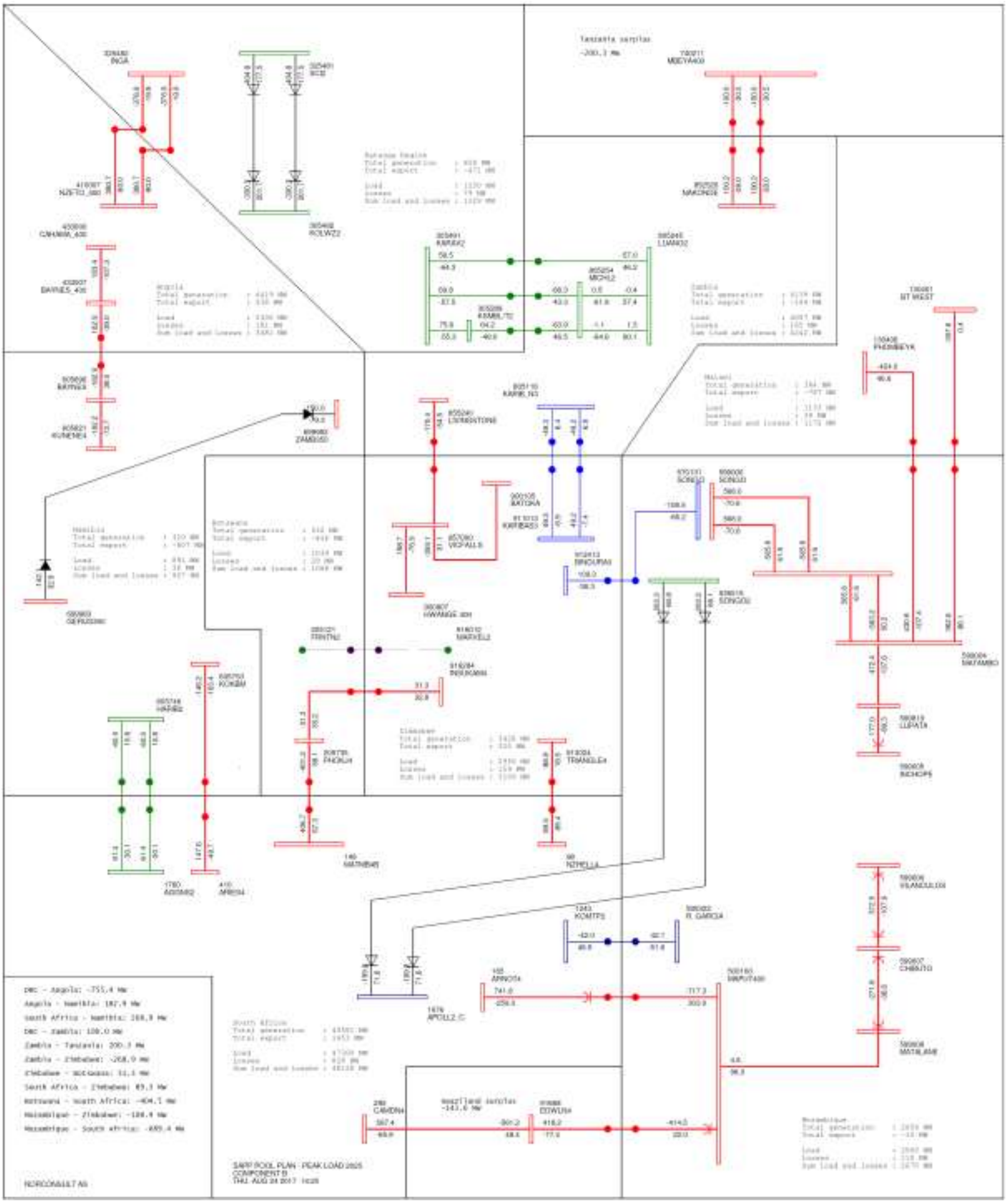


Figure 53 Stage 2030 – Component B

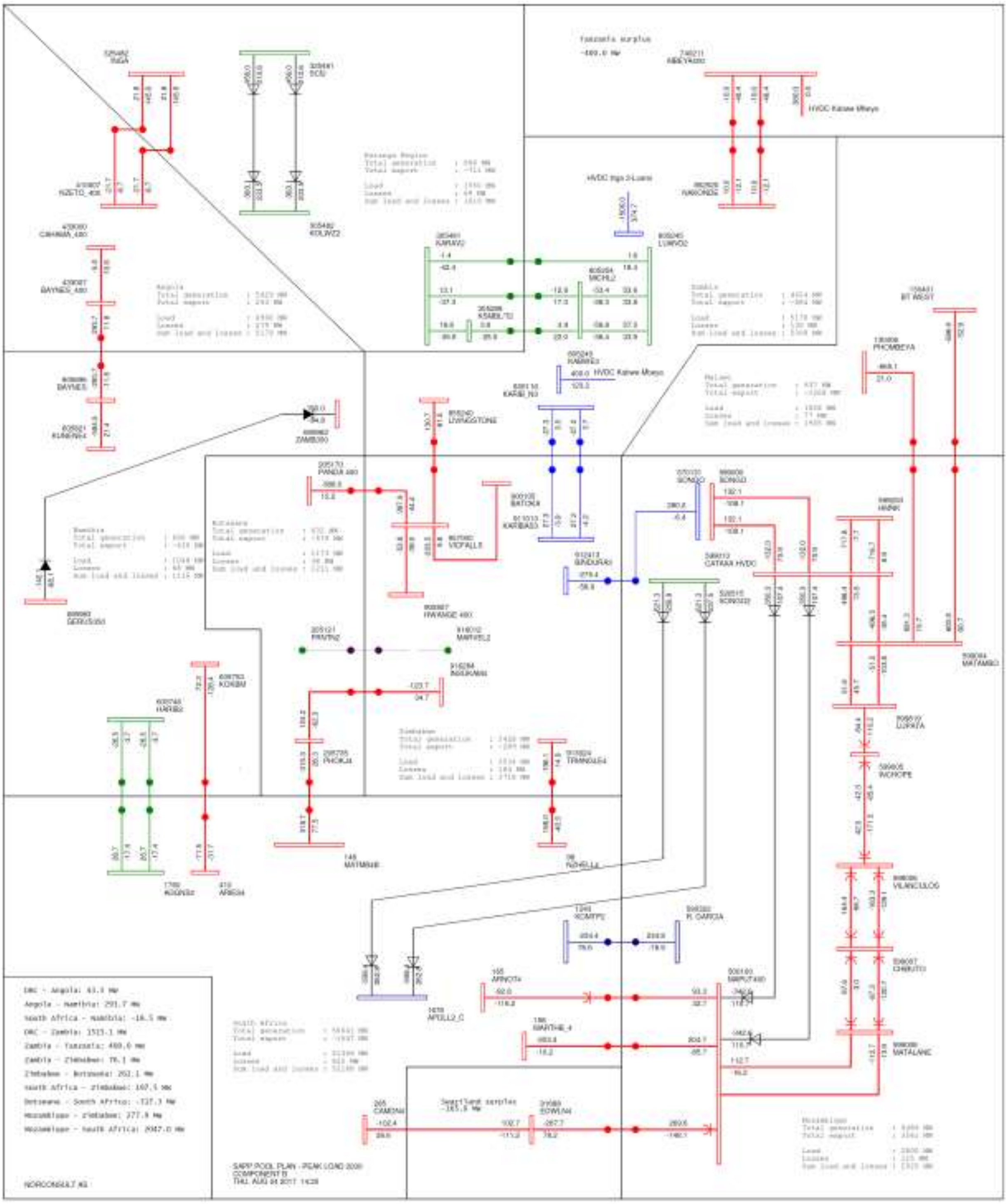


Figure 54 Stage 2020 – Component C

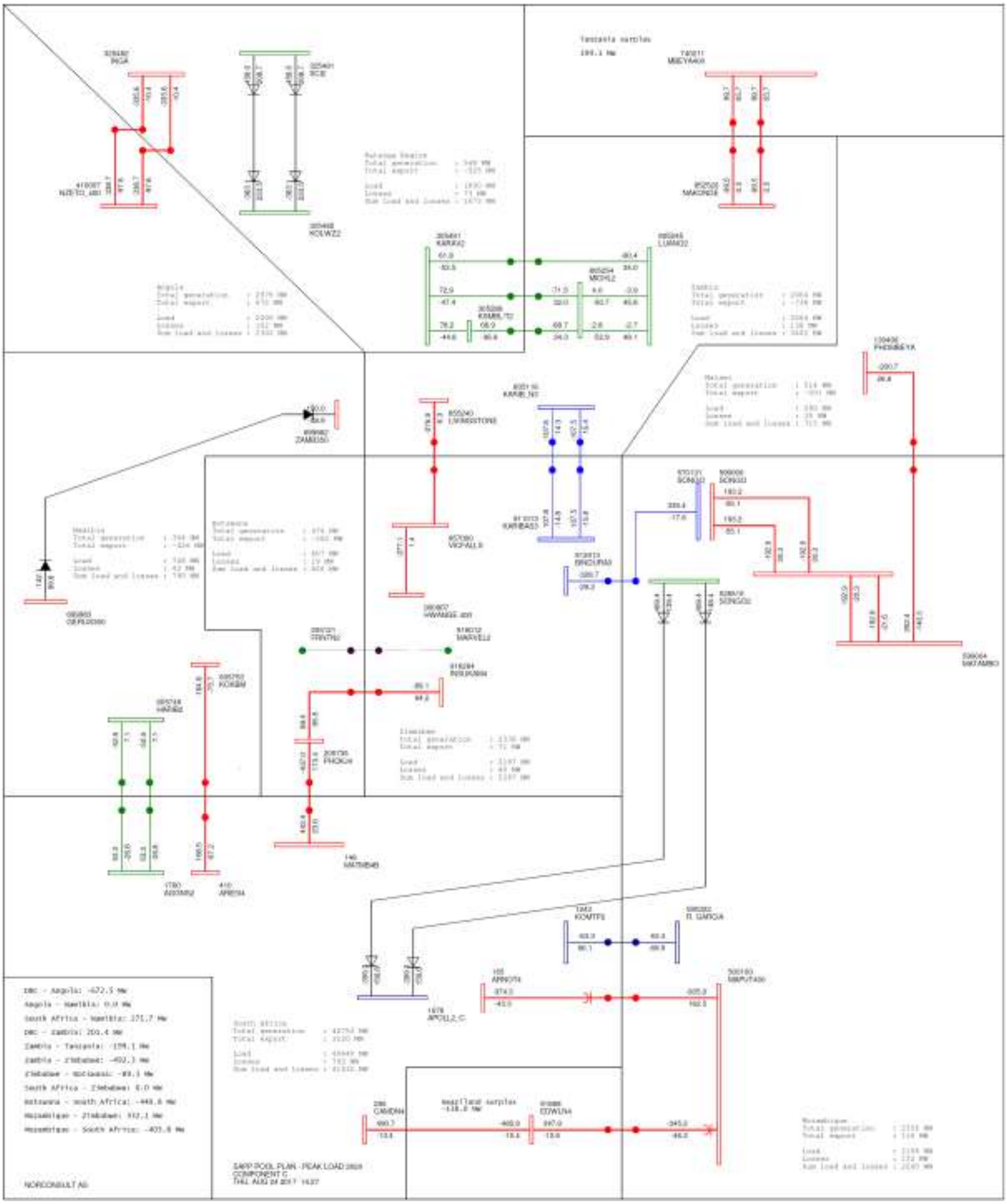


Figure 55 Stage 2025 – Component C

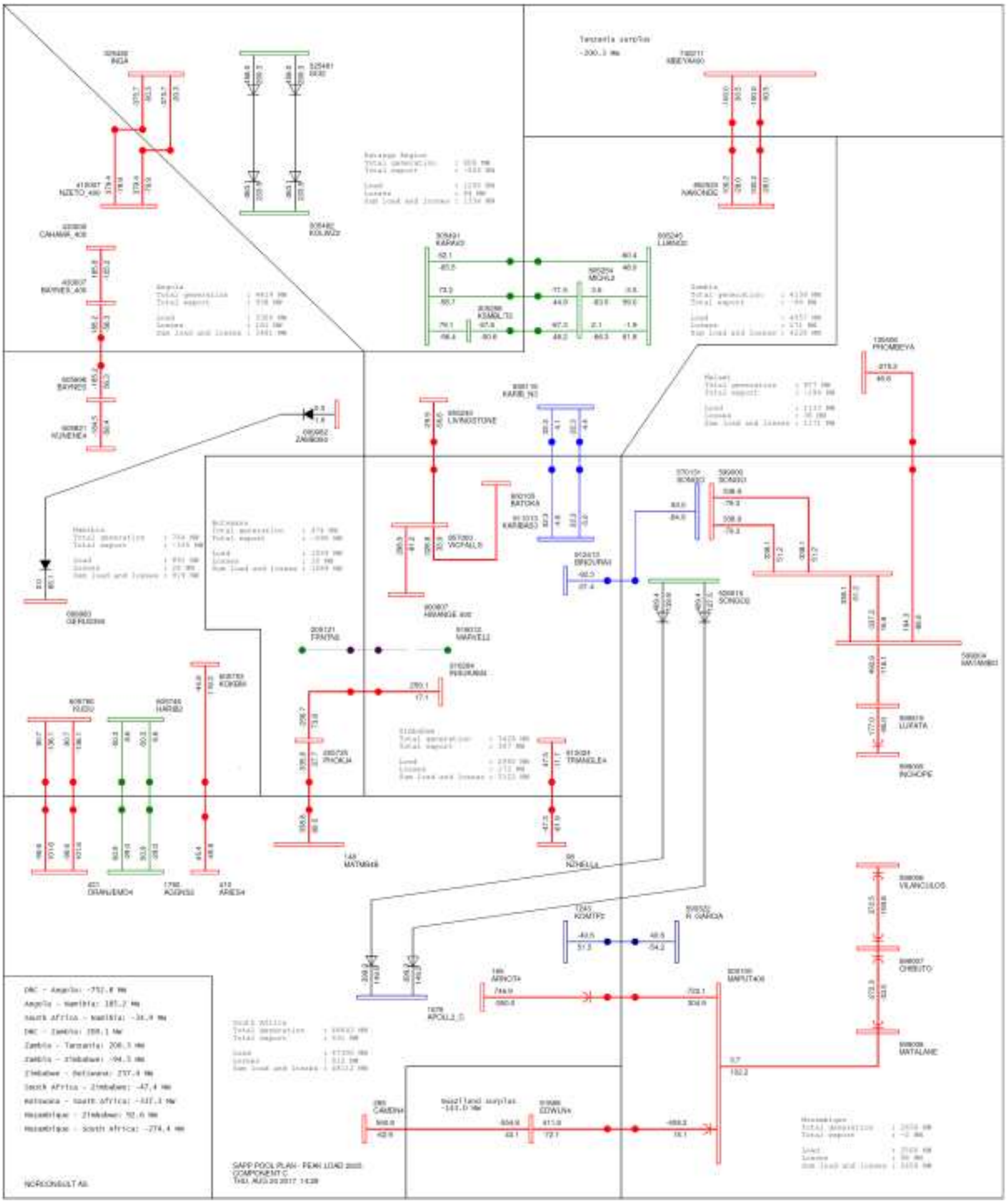
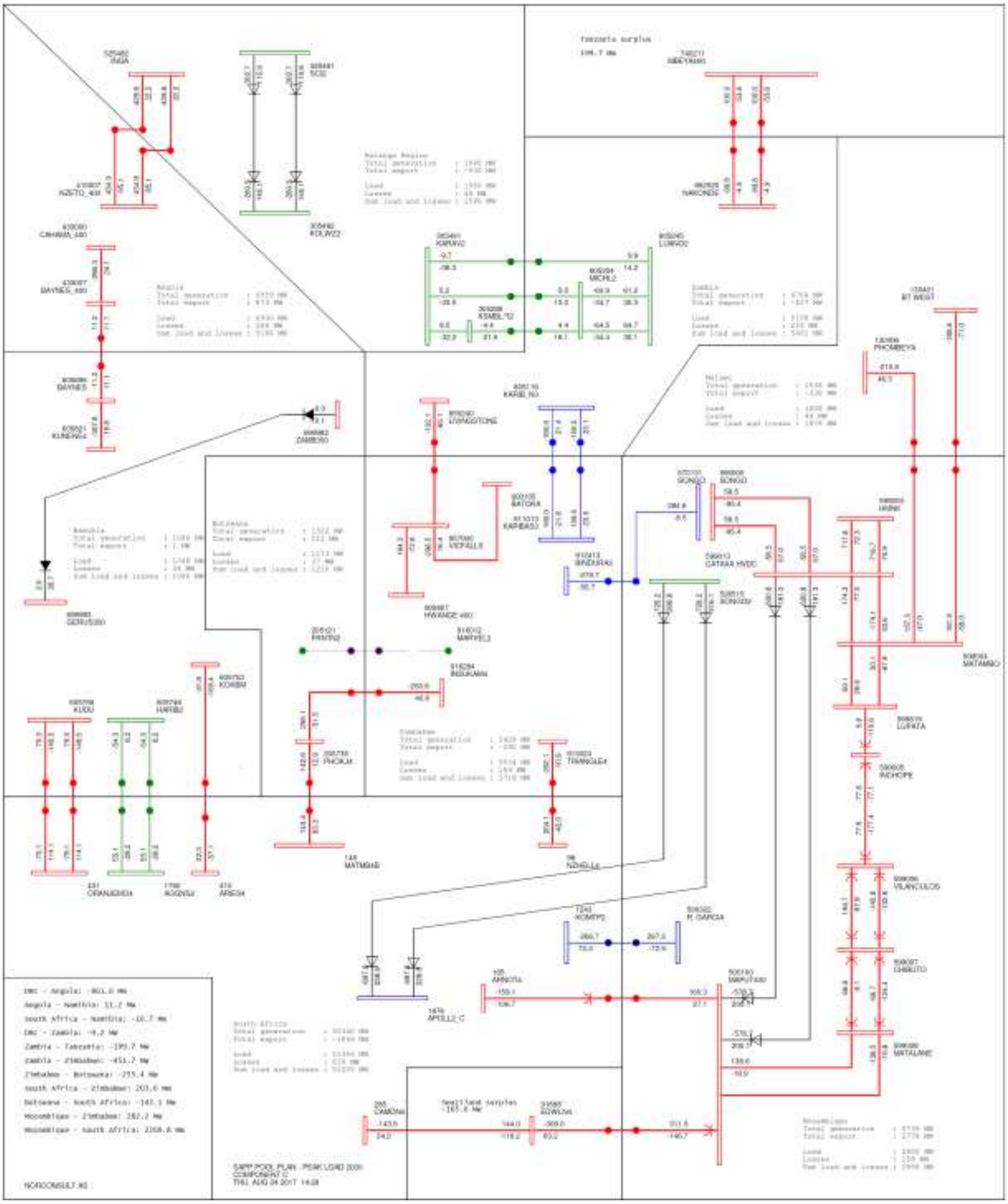


Figure 56 Stage 2030 – Component C



A8 TOR Compliance Table

An attempt has been made to make the Main Volume as accessible and readable as possible, but this has resulted in the layout deviating somewhat from the structure of tasks in the TOR for the Pool Plan study. Table 168 below provides a compliance table so that readers can easily see where responses to various aspects of the TOR are to be found in the final Pool Plan documents.

Table 168 TOR compliance table

TOR	Section/Annex
Component A	
Task A1 – Spatial mapping of energy resources and baseline data collection	Sections 2.1 and 8; Annexes A4 and A5. Full database has been handed over at end of study.
Task A2 – Demand Study	Section 2.2; Annexes A1 and A2.
Task A3 – Country Planning Studies	Sections 2.3, 4, 6 and 7.
Task A4 – Development of a benchmark scenario based on independent country generation and transmission plans	Component A sections in regional and country plan sections of Main Volume. Sensitivity tests were added – reported on in Section 9.1.
Component B	
Task B1 – Identification of potential cross-border / inter-regional transmission projects	Transmission projects derived through the iterative process described in Section 2.5.
Task B2 – Simulation of Full Regional Integration	Component B sections in regional and country plan sections of Main Volume.
Task B3 – Cost benefit analysis (transferred to Component C)	Changed on observation that it was more useful to undertake detailed analysis on the realistic than the theoretical case study.
Component C	
Task C1 – Development of intermediate regional integration scenarios	Component C sections in regional and country plan sections of Main Volume.
Task C2 – Scenario analysis with varying assumptions on key parameters and risks	Section 9.2.
Task C3 – Cost-benefit analysis of Realistic Integration Scenario	Section 10; includes Real Options Analysis.
Deliverables	
Separate reports on Components A, B and C	Subsequent agreement on only having a single consolidated report due to inter-relatedness of the Components.
Consolidated overall **Pool Plan Report**	This report – Executive Summary, Main Volume, Annex Volume, supporting tables in excel.
Two **Training Workshops**	Completed in March 2016 and June 2017

A9 Matrix of comments on Draft Final Report and responses in Final Report

Comments on Draft Final Report

Page numbers cited in the comments have been put onto a uniform basis that refers to the actual page numbers in the Main Volume and Annex Volume, rather than to the pdf page numbers which were used in some of the comments that were sent.

1. Angola

No comments provided

2. Botswana

S/N	Page no.	Description	Comment	Response
		Map quality	Visibility of the maps needs to be improved, the map keys are not clear. Some colours in the map legend are similar and this makes it very difficult to distinguish between the different parameters. I.e the blue codes used in figure 1 look similar, same applies to the yellow and purple codes	Done, in part through maps inserted into the report being made larger. High resolution version of the report should be consulted for best map quality. Original files for maps are being provided separately to the Coordination Centre.
2.1	6	Figure 1	There is a black colour in the legend (figure 1) depicting where coal reserves are located in the SAPP region yet in the actual map this is not shown	Corrected in Final Pool Plan, where separate maps are provided for each resource.
2.3.2	15	Country Planning Studies -	For Botswana, it has to be indicated	Text has been changed to

S/N	Page no.	Description	Comment	Response
		Overview	that the country's Master Plan at the time of data collection, was still being revised for horizon 2017 to 2027 hence what was availed was power point slides that show the supply-demand outlook and the generation expansion plans for the period of 2015-2025. This omission make it sounds like the Country does not do proper energy planning.	indicate that planning was in progress.
			Still under the same section, the planned interconnectors such as BOSA (Botswana – South Africa), ZIZABONA (Zimbabwe, Zambia, Botswana and Namibia) have to be acknowledged to address the assumed non-firm contracts	Comments added on future interconnections under consideration.
2.4	24	Component A transmission projects which were agreed	BOSA project has not been taken into consideration. This is the project which is at the same level of commitment with MOZISA and ZIZABONA. Non-consideration of this project, distorts the transmission planning.	The BOSA project was not among the interconnection projects agreed to be treated as committed following the workshop in Johannesburg in December 2016. The projects identified were the Triangle – Nzhelele line as part of the MOZISA project (but not the Orange Grove – Inchope

S/N	Page no.	Description	Comment	Response
				line), the Livingstone – Hwange line via Victoria Falls (but not the Victoria Falls – Pandamatenga and Livingstone – Sesheke/Zambezi/Katima Mulilo lines), and the Kasama – Nakonde – Mbeya line. The other components of MOZISA and ZIZABONA are evaluated as part of Component B and C along with a number of other regional transmission corridor projects – including BOSA. Component A therefore reflects trade based on existing as well as 'committed' interconnectors as agreed in December 2016. The decision made by the PSC at the workshop means that the Victoria Falls – Pandamatenga line and the BOSA project is not seen as an alternative to the trade corridor opened up by Livingstone – Hwange and Triangle – Nzhelele, but additional benefits are evaluated as part of the PLEXOS simulations in Components B

S/N	Page no.	Description	Comment	Response
				and C. The Consultant agrees that this approach has an impact on the viability of the BOSA project (and the Victoria Falls – Pandamatenga line), but the assumptions are in line with the decision made by SAPP PSC.
3.2	34	Table 10 Thermal and renewable projects in the benchmark case	Table 10, needs to be corrected as follows: i. The installed capacity for the country's **coal** plants are a. Morupule A : 4 x 33 = 132 MW (118MW sent out) b. Morupule B: 4 x 150 = 600 MW (528MW sent out) Total installed capacity = 732MW on **Coal plants.** This is just for coal fired plants only since this section is concerned about the COAL plants ii. The Morupule B 5&6 is planned for 2019 not 2029, the expected capacity is 300MW not 132MW Please provide full details of the 350MW for better appreciation.	Table 10 has been corrected. The remaining 350 MW is generic capacity from the candidate project list.

S/N	Page no.	Description	Comment	Response
			Refer to attached spreadsheet.	
3.2	36	Incorrect reference	Incorrect table reference on summary of hydropower projects, it should refer to table 11 instead of table 10	The cross-reference has been corrected.
3.2	39	Map showing location of key hydro projects	Figure 7 (Map showing the location of key hydro projects). The legend shows plant status as follows: ● Candidate ■ Committed ■ Existing Is this for Hydro projects as well since if it is the case, it would be incorrect for Botswana The legend does not indicate what the blue colour stands for and we see it a lot in Botswana	Corrected.
3.5	49/50	Figure 16 Exporters and importers in the SAPP region in 2020, 2025, 2030 and 2035	(Figure 16 list as comment #8, but no text provided)	No action required.
		Country generation plans	Refer to comments in the attached draft final report and the spreadsheet. This section needs to be revised in line with our comments (notably that installed capacity in Botswana varies	Corrections have been attended to. See below for revised values used in C+ scenario.

S/N	Page no.	Description	Comment	Response
			between 800 MW in Component A and 1064 MW in Component C). We have corrected these excel sheets before but it does not look like our corrections were taken into consideration. Please use the formula to calculate the corresponding energy values as we have only corrected the capacity values.	
		Spreadsheet adjustments	Corrections are Francistown diesel 70 MW (2017-2040), Orapa diesel 90 MW (2017-2040) and solar PV 100 MW from 2019; previous values Francistown diesel 105 MW (2017-2019), Orapa diesel 90 MW (2017-2021) and solar CSP 100 MW from 2031.	Changed the Francistown diesel back to 90 MW. Removed the decomissioning date for Orapa diesel-fuelled unit. Corrected the Morupule B power to 300 MW total. Added the 100 MW Solar PV power plant. Corrected reporting for the CSP, so it is not reported as available from 2017 anymore. Morupule B power corrected to 300 MW.

3. DRC

S/N	Page no.	Description	Comment	Response
		Excel file SAPP Pool Plan - Generation Annex table Component B	Binder, line 219: Update the table. The other groups of Kyimbi (Bendera) will be equipped from 2025. Hence we will have 41 MW from 2025	Corrections made in final table.
			Same for line 224, an extension is planned for the Mobayi power station, from 2022. We will have an additional 19 MW.	
			Lines 231 and 232: Ruzizi 1 and 2 do not have the same power. 29 for the first and 44 for the second.	
			Lines 273 and 274: the commissioning of Busanga is for 2020 and 2022 for Ruzizi 3.	
A3.2	113	Annex Table 96	• the Inga 3 BC power is 4,800 MW not 240 MW • Nzongo 2; installed capacity is 150 MW not 108 MW (name different as well)	Values changed in Revised Annex Table 96
	34	Main volume Table 10	P_DRC_Likasi (PV) : (Likasi, Lubumbashi and Kolwezi) consider 100 MW per city not 200 MW.	Comment does not relate to Main Volume, Table 10, but noted for the PLEXOS model.

4. Lesotho

<table>
<tr><th>S/N</th><th>Page no.</th><th>Description</th><th>Comment</th><th>Response</th></tr>
<tr><td>4.4</td><td>65</td><td>Monon'tsa pumped storage scheme</td><td>“It is to be noted that the Monon'tsa 300 MW pumped storage scheme, which is quintessentially a regional project, is not part of the investment sequence, but it seems likely it would be selected close to 2040 if the planning horizon were to be extended” Mononontsʼaʼs Pumped Storage is estimated at 1200MW</td><td>Capacity of Mononontsʼaʼs Pumped Storage corrected in the text.</td></tr>
<tr><td>A1.4.1</td><td>24</td><td>Annex Table 17 Lesotho’s national electricity demand forecast</td><td>With the info provided the table should look like this:
<table>
<tr><td>2015</td><td>177</td><td>706</td><td>46.00%</td><td>-</td><td>-</td></tr>
<tr><td>2016</td><td>196</td><td>740</td><td>43.00%</td><td>10.70%</td><td>4.80</td></tr>
<tr><td>2017</td><td>218</td><td>774</td><td>41.00%</td><td>11.20%</td><td>4.50</td></tr>
<tr><td>2018</td><td>223</td><td>819</td><td>42.00%</td><td>2.30%</td><td>5.80</td></tr>
<tr><td>2019</td><td>230</td><td>864</td><td>43.00%</td><td>3.10%</td><td>5.40</td></tr>
<tr><td>2020</td><td>238</td><td>914</td><td>44.00%</td><td>3.50%</td><td>5.70</td></tr>
<tr><td>2021</td><td>244</td><td>962</td><td>45.00%</td><td>2.50%</td><td>5.20</td></tr>
<tr><td>2022</td><td>251</td><td>1,015</td><td>46.00%</td><td>2.90%</td><td>5.50</td></tr>
<tr><td>2023</td><td>261</td><td>1,069</td><td>47.00%</td><td>4.00%</td><td>5.30</td></tr>
<tr><td>2024</td><td>267</td><td>1,124</td><td>48.00%</td><td>2.30%</td><td>5.10</td></tr>
<tr><td>2025</td><td>271</td><td>1,181</td><td>50.00%</td><td>1.50%</td><td>5.00</td></tr>
<tr><td>2026</td><td>279</td><td>1,238</td><td>51.00%</td><td>3.00%</td><td>4.80</td></tr>
<tr><td>2027</td><td>290</td><td>1,297</td><td>51.00%</td><td>3.90%</td><td>4.70</td></tr>
<tr><td>2028</td><td>295</td><td>1,357</td><td>53.00%</td><td>1.70%</td><td>4.60</td></tr>
<tr><td>2029</td><td>309</td><td>1,419</td><td>52.00%</td><td>4.70%</td><td>4.50</td></tr>
<tr><td>2030</td><td>314</td><td>1,482</td><td>54.00%</td><td>1.60%</td><td>4.40</td></tr>
<tr><td>2031</td><td>319</td><td>1515</td><td>54%</td><td>1.60%</td><td>2.20</td></tr>
<tr><td>2032</td><td>324</td><td>1558</td><td>55%</td><td>1.60%</td><td>2.80</td></tr>
<tr><td>2033</td><td>329</td><td>1591</td><td>55%</td><td>1.50%</td><td>2.10</td></tr>
<tr><td>2034</td><td>336</td><td>1648</td><td>56%</td><td>2.10%</td><td>3.50</td></tr>
<tr><td>2035</td><td>342</td><td>1690</td><td>56%</td><td>1.80%</td><td>2.50</td></tr>
</table></td><td>Annex Table 17 has been corrected. The demand figures agreed with LEC and used in the model runs are in Annex Table 25.</td></tr>
</table>

5. Malawi

No comments received.

6. Mozambique

S/N	Page no.	Description	Comment	Response
		SAPP Pool Plan Generation Annex Tables (Excel file)	In the table attached there is highlighted in red should be removed for the follow reasons: • Beloluane 40MW has been decommissioned this year 2017 • Nacala 18MW has been decommissioned 2015 • CDM Diesel is not connected to EDM grid • Luis Cabral remove from the list • Tavene and Inhambane are very small plants and only are used in peaking time and We understand that should be removed • Temane and Temane 2 are off grid powers plants should be removed	Some of the plants that are now removed in Component C+ were added in the last EDM submission for Component C. • Beloluane removed from the model (set to 0 units). • Nacala also removed from the model. In the last revision the number of engine units was corrected from 11 to 18 1 MW units, but for C+ set as 0 units from the start of the simulations. • CDM 1 diesel unit removed from the model (also set to 0 units). • Luis Cabral, similar to CDM 1. Set to 0 units. • Tavene – set to 0 units. • Inhambane – set to 0 units. • Temane and Temane 2

S/N	Page no.	Description	Comment	Response
				engines – both set to 0 units. All the plants above with 0 units should not appear in the report tables, but are in the model and the corresponding Excel reporting sheets in order to avoid cross-referencing troubles. Early PLEXOS runs indicated no or marginal regional trade via an interconnection between Mozambique and Tanzania. Major internal grid investments are also required to support significant trade. Note also that the costs of potential future gas fired generation on either side of the border are presumably similar. An interconnection may though have local benefits in view of minimising costs for grid extensions to meet demand in the border areas.
			• Remove all CCGT NG repeated and is not official knows in planning those projects	
			• Add Temane 100 MW for the year 2022 • Add Lupata 600 MW for the year 2025 • Add Boroma 200 MW for the	Added Temane 100 MW gas fired power plant, as well as Lupata 600 MW and Boroma 200 MW. These have all been in the model at some point, and then

S/N	Page no.	Description	Comment	Response
			year 2025	removed and now restored.
		PLEXOS excel results file	In the dropbox file excel file model CLT +MT V06 sample please rectify Moz – Zambia line is 400kV and not 330kV.	The interconnection is modelled as 400 kV. Incorrect labelling in PLEXOS files corrected.

7. Namibia

No comments received.

8. South Africa

Eskom Transmission Planning Response to the SAPP Pool Plan Report issued in 2017

Eskom's Comments	Response by Consultant
Eskom is currently experiencing more than 6GW of excess capacity and there are a number of Generation projects that are on the pipeline. It is planned that the Medupi and Kusile generators will be fully commissioned before 2022 and this will push up the excess even higher. A number of IPP's are also in the commissioning phase which will push the surplus even further. Even without the IPP's, the current generation fleet including the total commissioning of the Medupi and Kusile PS will have surplus well into the future. The rest of SAPP on the other hand is experiencing a deficit. With a number of generation projects still not in contracting phase yet. Although there is a deficit in the region, Eskom is unable to fully	The regional deficit is reflected in the PLEXOS simulations: • Only South Africa and Mozambique have surplus energy in 2017/18. • Some existing interconnections are fully loaded in the first few years. The regional deficit in recent years seems to be closely linked with the low output from hydro power plants due to very low inflow at least on part of the hydro system. The inflow in the base case in PLEXOS is reflecting 'normal' inflows and regional deficits are therefore likely lower than

Eskom's Comments	**Response by Consultant**
supply the countries that are experiencing this deficit as there is inadequate Transmission infrastructure to export power to the region.	recent historical figures. Some ongoing projects will change the balance in other SAPP countries as well, for instance: • Kafue Gorge Lower (ongoing) reduces deficit in Zambia by 2021/22. Other projects that are part of the least-cost plan in Component C may be more uncertain – especially the timing of the plants. For instance, Batoka Gorge in service by 2023 may be too optimistic, but the important message is that it is part of the least-cost expansion plan early on. Adding the committed ZISA line as early as possible may certainly seem preferable, and also possibly pushing the capacity of the system by adding and SVC in the Tokwe-Triangle area may provide benefits.
From the background above and after evaluating the PSSE casefiles provided, Eskom's response is as follows:	The PLEXOS simulations provide the generation expansion plan and energy export/import for each country, and the economic viability of additional interconnections are also tested in PLEXOS. The PSS/E files are used to evaluate transfer limits for different interconnection candidates etc.
We require clarity on how only one interconnector in the short term is proposed to be implemented i.e. ZISA. With the surplus Eskom is experiencing and the current deficit experienced in the SAPP region, exports from South Africa should be viable at least until 2025 where most of the Hydro power projects in SAPP would have materialized. Clarity is therefore sought after on why more interconnectors were never proposed at least to SA's immediate interconnected countries such as Namibia, Botswana, Zimbabwe	Note that the ZISA interconnector is included as a committed project following the agreement made at the workshop in December 2016 (i.e. it is not proposed as a project based on the Pool Plan studies). We agree that higher levels of export from South Africa may have been seen recent years had more interconnections been in place, see also comment above on some interconnectors running at full capacity until new generation and transmission projects are realised. Which projects

Eskom's Comments	Response by Consultant
and Lesotho as they are experiencing a deficit and they will for quite a while. Power exports to these countries is possible and our view is as follows:	are viable in the future depends on whether countries that have experienced deficit will continue to do so or if domestic generation projects will be added to meet demand. Components B and C shed some light on this issue, and notably, South Africa exports more power initially in Component B than in Component C. South Africa continues to export until 2026 in Component C – peaking at 8-9 TWh per annum in 2021/22. Note that the installed capacity as modelled in PLEXOS exceeds the peak demand in South Africa by more than 10 GW even by 2025 (higher earlier on). The excess capacity therefore seems to be accounted for.
South Africa Export possibilities	
Namibia Namibia is bordered by Angola, South Africa, Botswana and Zambia. - Botswana for the duration of the study has a deficit and thus cannot supply Namibia - Angola for the duration of the study has a deficit in the south. Although the country has an overall surplus, the Transmission network is not interconnected from the North, Central and the South. We thus do not understand the rational of the proposed interconnector between Namibia and Angola due to a deficit in the southern	PLEXOS results for Component C shows that Namibia will be importing on short term. - In Component C, Botswana will be importing initially (up to 5 TWh p.a.). Local generation increased on medium term (2026/27). - Angola is planning to interconnect the three regions. In a regional perspective, it would therefore make sense to connect Angola and Namibia as well – thereby opening up for trade of surplus capacity from Angola. The Baynes project may be (or become) part of such development. Even limited trade of surplus energy from Angola is found to justify the interconnection assuming Angola will be interconnected from north to south. - The PLEXOS simulations indicate that the power flow on the existing link between Zambia and Namibia in many scenarios is limited, and

Eskom's Comments	Response by Consultant
Angola network. - Its only on Component A (which is the benchmark case) that Zambia has a surplus, otherwise Zambia overall is also experiencing a deficit and thus cannot supply Namibia into the future	the upgrade of the link is not viable early on. - A second 400 kV line between South Africa and Namibia is part of the plan by 2024 in Component C – partly linked to the development of Kudu: o In a scenario without the Angola – Namibia link early on, the second 400 kV line between South Africa and Namibia is likely to be viable earlier than 2024. o The cost of the second interconnection from South Africa to Namibia is partly dependent on plans for further extension of the 400 kV grid in South Africa.
Botswana Botswana is bordered by Angola, Namibia, Zambia and Zimbabwe. Botswana for the duration of the study is in a deficit. It is unclear why BOSA (Botswana –South Africa) or another interconnector was not proposed to export power from South Africa as Botswana is in a deficit for the duration of the study.	In Component C, PLEXOS indicates Botswana will import until 2025/26. The requirement in Component C to meet own demand means that coal units are added and marginal costs of generation indicates that Botswana may export in some years later on. In a scenario with Botswana relying on imports from South Africa, it may very well be economical to add a second 400 kV line between the two countries early on. Such a scenario has not been studied in the Pool Plan. It may be that such a scenario is covered in the BOSA study (the results from this study has not been available to the Consultant on the Pool Plan). We would imagine, though, that a connection from the generation hub at Matimba/Medupi may be a better option than the link to Watershed in order to meet demand in Botswana in such a case. The link between Isang and Watershed would seem more suited for wheeling from north to south on the SAPP grid.
Lesotho Lesotho is bordered by South Africa and the country is at a deficit for the duration of the study.	Noted.

Eskom's Comments	Response by Consultant
- We agree that another interconnector is required for power intake	
South Africa Import possibilities - Looking at the casefiles, it shows that Eskom's current fleet is reduced or not committed in order to allow for imports. Clarity is sought after on why this was done as this will definitely distort the picture. The consults must be aware that proposing this, basically suggests that SA should place the current fleet on cold reserve and should limit/ reduce the outputs of the most recently built generation, such as Medupi and Kusile. This surely cannot be financially and technically wise. Clarity is therefore sought after on why this is so.	- The trade in energy is determined from the simulations in PLEXOS. The PSS/E case files reflect the results of PLEXOS and not the other way around. - There are plants in other countries that are not running at full capacity as well. - Furthermore, for Zambia and Zimbabwe for instance, the study has partly considered wet seasons with high output from hydro plants and low output from thermal units vs. dry seasons with low output from hydro plants and high output from thermal units. Minimum load factors have been applied for some thermal plants, however, in general, the study looks at economic least-cost operation and expansion of the overall system.
Plexos Input for RSA	
A detailed Plexos (RSA IRP 2015 Model) was originally submitted to the consulted at the Consultation and First Training Workshop in Johannesburg on 14-17 March 2016. This model contained detailed supply options, that is existing, committed and candidate generation technologies for the RSA ESI. In particular the wind and PV overnight capital; costs included the learning rates based on the successful RE Bid programmers. Included in this model was the also the Greenhouse Gas Emission trajectory constraints as per the RSA COP commitments. It was evident in the portfolio of new technologies for RSA that the model the consultants used did not	It is correct that an explicit learning rate, or in effect the *decrease* of renewables' investment cost over time, was *not* incorporated into the modelling. Instead, a simplified approach was adopted so a constant average investment price for renewable options that factored in future reduced costs was used in the PLEXOS model, for all of the countries consistently. This was a pragmatic decision that needs to be evaluated in a broader context of the PLEXOS model for the SAPP Pool Plan. Extrapolating from SA data directly to other countries could be problematic, especially

Eskom's Comments	Response by Consultant
take into account the reducing costs of wind and PV.	with learning rates for new technologies that require advanced knowledge in managing the power system (forecasting and balancing of renewable power). This would result in differences in the learning rates in other countries.
Again, at the Dissemination and Second Training Workshop on 26-28 June 2017, it was evident from the different component results that the learning rates of both PV and wind were not taken considered in the consultant's model. After robust debates between the Eskom planners and the SAPP Pool Plan consultants it was agreed that the Eskom team would provide consultant with the RSA RE data to be used to generate the SAPP Pool Plan. On the 3rd July 2017 the Eskom Planners forwarded Mr Peter Robinson an email with the relevant wind and PV costs applicable for the RSA conditions for use in the latest SAPP Pool Plan model.	Please see the comment above. The consultants agree the overall project results certainly indicate that the renewable options should be investigated in more detail. However, this investigation should depart from the current SAPP PP results and go much deeper in addressing the renewables issues: the treatment of capacity contribution of renewables, the renewables' impact on day ahead and intra-day dispatch, the impact of forecasting errors on balancing, large-scale regional smoothing effects on forecasting errors etc. Just including the investment learning rate in the current long-term PLEXOS model could well have delivered misleading results.
Even though the overnight capital costs have been reduced in the current 2017-08-22 SAPP Pool Plan 2017 v223, this reduction is not in accordance to the above email submission. In other words the learning is not consistent with the one provided to the consultants. Fixed and variable o+m costs were however changed accurately.	Again, please see the comment above. The investment prices which were circulated by the consultants were used consistently in the model, in line with the above comments.
<u>Plexos outputs</u>	
The consultants recommend key regional projects (both transmission and generation) are not on the basis of a 'free least costs plus regional benefit but are based mostly on the committed country projects. For instance, Mphanda Nkuwa and Tete coal together with Inga 3 and 4 are forced into the Plexos model and when this happens the Plexos model is forced to choose STE and	Note Mphanda Nkuwa, Tete Coal and Inga 3 and 4 are <u>candidates</u> in Components B and C. These projects are <u>not</u> treated as committed in these scenarios (therefore the change in timing as well). It is correct that the STE grid is the only grid option that can provide adequate capacity for evacuation of high levels of power from the Tete

Eskom's Comments	**Response by Consultant**
the Inga Limpopo and Inga Luano transmission projects. Th definition of committed projects was revisited and the Dissemination and Second Training Workshop on 26-28 June 2017. Only projects that are either in construction or have reached financial close should be considered as committed projects.	area. It is strictly speaking not linked to Mphanda Nkuwa as such, but Mphanda Nkuwa is a low-cost project that would require the transfer capacity of the STE grid or a similar option. The report states that the design of the STE grid may possibly be modified – reducing the overall investments costs, but it is hard to see a better alternative than the DC link from Cataxa to Maputo. The study has furthermore considered upgrading Songo – Bindura – Dema, and also includes links from Tete to Malawi and Zambia to reach other markets in SAPP and thereby providing capacity to evacuate power from the Tete area. The MOZI part of the MOZISA project has also been studied in order to add capacity for export from Mozambique. The HVDC links Inga – Limpopo and Inga – Luano are candidates for evacuation from Inga. Timing and sequence is selected by PLEXOS. Early on, an HVDC link from Inga to Tanzania was also evaluated, but a decision on such a project would be closely linked to possible high capacity links for instance from Ethiopia as well, and this issue was therefore considered to be outside the scope of the SAPP Pool Plan Study. The report also comments on Inga – Lubumbashi/Katanga as an alternative to Inga – Luano. The latter is recommended. An alternative to the Inga – Limpopo HVDC link may be a link via Angola, Namibia and Botswana. From the perspective of the Pool Plan, it is hard to point to any specific issues that may make one of the options stand out as better than the other. The shortest line route possible, is likely to be via Angola. This issue may be expanded on in the Final Report.

9. Swaziland

S/N	Page no.	Description	Comment	Response
A1.9.1	72	Annex Table 58: Swaziland's demand forecast summary	The demand forecast (GWh) is accurate, however the demand forecast (MW) is not in line with the Swaziland Electricity Company Demand Forecast Update (Source). For accurate results kindly refer to Table 7-1 of The Swaziland Electricity Company Demand Forecast Update report.	Annex Table 58 has been corrected. The demand figures agreed with SEC and used in the model runs are in Annex Table 62.
		SAPP Pool Plan Generation Annex Tables (Excel file)	Component A – Installed and planned capacity - Swaziland • Add Lavumisa 5 MW Solar PV plant as a committed plant. Commissioning planned date is 2019 • Change P_Swaziland_Lubombo Coal to P_Swaziland_Lubhuku Coal	Corrections made.

10. Tanzania

No comments received.

11. Zambia

S/N	Page no.	Description	Comment	Response
	ix	Abbreviations – BC and HC	Both are referring to same project i.e. Inga 3. If these are phases of development need to indicate this fact.	The phased development has been clarified in the acronym list.
	xiii	Utility Acronyms - CEC	Correct "*Company*" to '**Corporation**'	The correction to 'Corporation' has been made.
1.3	3	Section 1.3 title – SADC generation planning criteria	Should it not be '**SAPP**' instead of "*SADC"?*	It should indeed by SAPP generation planning criteria. Correction has been made.
1.3	3	Section 1.3 – "*The Reliability Criterion goes beyond just meeting the maximum demand to require a reserve margin to be maintained, but it is important to note that SAPP permits the Reliability Criterion to be met through a country contracting firm power including auxiliary services from its neighbours*".	Consider using '**ancillary**' as opposed to "*auxiliary*".	This correction has also been made, as ancillary is the correct term.
1.4	4	Section 1.4	Consider deleting the whole of this section. The value add to the Study Report is not clear – the Consultant might want to consider communicating its challenges during the execution through separate	Deleted.

S/N	Page no.	Description	Comment	Response
			correspondence to the Employer.	
2.4	23	Section 2.4: Assumptions that result in anomalous Component A results – "*After considerable discussion at the workshop in Johannesburg in December 2016, the only interconnectors in Component A are as follows*:"	Consider recasting to remove the process of arriving at the resolution e.g. 'Interconnectors considered in Component A are as follows:'	Substantially modified.
2.4	24	Section 2.4: Sensitivity test Component A –	Consider recasting to remove the process of arriving at the resolution. Authorizations on how this would be done (load forecast review by Consultants) were given by the PSC, the same one now presenting its Report	Text changed accordingly.
2.8	26	Section 2.8: Fuel Prices –	Consider recasting to remove the process of arriving at the resolution	Ditto.
3.1	33	Section 3.1: Box 1 Unserved Energy in the SAPP Pool Plan analysis – i) Angola has 264 GWh of unserved demand (0.5% of total demand) ii) Lesotho has used up all	i) Is the "0.5% of total demand" value to national or regional? ii) For Lesotho example consider using similar comparative as for Angola case for consistency and readability.	The 'total' demand is total national demand. Text has been adjusted so that unserved energy in Angola and Lesotho are described in the same way. A separate sub-section 2.9 has been created for unserved energy. The corrected text now

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		transmission capacity for imports and has 81 GWh of unserved demand (3.8% of unserved demand).		appears in that sub-section.

12. Zimbabwe

No comments received.

13. World Bank

S/N	Page no.	Description	Comment	Response
A: PRESENTATION OF KEY MESSAGES AND USABILITY OF THE REPORT/OUTPUT				
		Key messages not sufficiently highlighted	Particular example: "An important conclusion from the study is that the transmission investments are relatively stable across the sensitivity analyses and are much cheaper than the generation projects".	Key messages, especially about transmission, reinforced in several places in the report: introduced in preview form in Section 3.2; details provided in Section 5.3; final Conclusions and Recommendations strengthened (Section 11).
			How does the average cost of	Average cost of energy was

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			electricity change between scenarios?	calculated for Component C and reported in Section 3.6.
			What are some of the potential challenges (e.g. technical, environmental) and what are the solutions.	This is a big question, beyond the immediate scope of this exercise. The contributions ECA is making to the Bank's flagship report on African power pools will attempt to provide some answers.
			Regional approach has lower cost than individual country plans – how is this broken down by country?	A summary section giving country-level outcomes has been included as an annex to the Executive Summary. Comment has been added that all countries will share in the benefits, and that the major exporters (DRC and Mozambique) are able to diversify their sources of foreign exchange earnings.
			Who are the winners (or losers for that matter)?	All countries share the benefits or regional integration under Component C. They invest in their own capacity to be able to meet peak demand and only import from other countries if this is less costly than own generation.

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5.3	190	*Another issue is the sudden loss of the interconnection between Angola and DRC and the impact on the link between Angola and Namibia…..In such a case, it may not be possible to keep the system in Angola in synchronism with the rest of SAPP via this relatively weak link.*	Country-level statements that should be reflected in regional section eg Angola transmission link	The summary of key findings in Chapter 5.3 has been expanded to reflect this and similar observations in Chapter 6 and 7.
		Database on dependencies between generation and transmission projects	Excel file rather than text (another excel annex)	New Table 13 in Section 5.3 is a useful addition but isn't quite what is being asked for. The transmission expansion plan is based on a certain region-wide generation expansion plan. Linking one transmission project to one generation project certainly does not work, while listing all possible dependencies would be un-usefully complex. As discussed in relation to Mozambique in Section 7.6, the interconnectors and the timing of these may easily shift if the generation expansion plans are altered. The impact is mostly towards the end of the study period, though. There is therefore ample time to adjust the transmission plans in line

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				with actual developments and further, more detailed input on the cost of the different generation projects.
11.3	245	Demand forecasting	The recommendation to undertake frequent forecasting should include a recommendation to work towards harmonizing methodologies for demand forecasting.	Good suggestion, now included in the final study recommendation.
2.4	23	Further observations on 'anomalous Component A results'	The report says demand was adjusted resulting in some "significant differences". However, the bench mark scenario includes plants from individual country plans and the result is that a number of plants are under-utilized. Could it be the case that the individual expansion plans were based on the national demand forecasts hence the results obtained? Please clarify this.	The section referred to says that "the demand forecast figures for the base year differed significantly from the actual figures supplied for 2015 and 2016, the discrepancy being attributed to suppressed demand". The team was told to use the projections that included suppressed demand because these were the figures being used for national planning, but in some cases, where the demand forecasts were significantly changed by the countries during the study period, there may be discrepancies between demand used in the national plans and the demand figures mandated

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				for the Pool Plan. However, the underutilisation of plants in the benchmark scenario is more likely to reflect politically-driven generation investments than different assumptions about growth in demand.
2.2	11-12	Demand forecasts for Malawi and Tanzania	Demand growth rates for Malawi and Tanzania are quite high. Consumption per capita for Malawi is between 125 and 760 for example. What accounts for the main difference between the Base and Low growth rates for these countries? Is this largely driven by access rate?	In most countries, the demand forecasts provided imply quite 'reasonable' rates of growth in demand. In the case of Malawi and Tanzania, there is indeed a strong desire to see per capita rates increase, not just in average across the whole economy but also through accelerating household access. In each case, the 'low' demand forecast is based on an assumption of lower economic growth and a slow-down in the pace of electrification.
B. TECHNICAL ANALYSIS				
2.8	27	LNG	Fuels: Which countries have LNG as an option for fuel? None of the plants seem to have operating costs that match the LNG price of 9-13 $/GJ.	South Africa has LNG as an option for fuel, but it is never chosen due to the high fuel price.
2.8	28	Generator capex - ICE	It looks odd that the cost per kW	The Eskom figure for ICE was

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			for an ICE is higher than for a CCGT. Given the options and scenarios under consideration, ICEs are not likely to play a role in the future plans because of operating costs but it is better to use a reasonable number. It may pose a modelling challenge for Scenario C when every country is expected to install enough capacity to meet peak demand because ICE's will be picked by the model for their lower capex. It is probably easiest to simply take it out as an option.	used. It is a high unit cost because relatively small ICE are assumed, whereas coal and CCGT reflect significant economies of scale.
		Solar PV	Why isn't PV an option (candidate plant) for all countries? In the annex, countries like Malawi, Botswana, Swaziland, etc. do not have PV as part of candidate plants.	The national power sector master plans were used, and in some cases (though not Malawi) PV was not included as an option. The Botswana Renewable Energy study indicates that when it comes to solar CSP should be chosen over PV. The range of renewables is increased significantly in the high renewables sensitivity test SC4 (Section 9.2.5).
3.1	31	Cost of unserved energy	It is striking that the consultant has taken out the cost of unserved energy in reporting the NPVs. Since	This is a misunderstanding, which has led to unserved energy being discussed in a

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			the NPVs are being rightly used for comparison, they must include all costs including any penalties (such as unmet demand). In fact, contrary to what the table of contents say, unserved energy results are not presented in the report or the annex. As a measure of reliability, this must be reported and included in the NPVs especially when comparing performance in the sensitivities.	separate new Section 2.9 and to the NPVs being reported (in Section 3.1) both with and without the cost of unserved energy (valued at $1,000/MWh); also in the sensitivity tests (Section 9) and in the economic analysis of transmission corridors (Section 10.4). A very large unserved energy penalty was included in the optimization ($3,000/MWh) to drive the solution towards deploying generation and transmission investments, but at the end of the planning horizon some unserved energy re-appears because of the step size involved in new generation and transmission investments.
9	221	Sensitivity tests	The sensitivity analyses were thoughtfully done. Were fuel cost sensitivities or a confluence of sensitivities such as low demand and low rainfall considered? This helps to understand how different uncertainties reinforce or mitigate each other.	Five sensitivity tests were as much as could be covered. Fuel prices were considered for a sensitivity test alongside other options. It is hoped that the single issue sensitivity tests provide sufficient insight to get a sense of the implicates of combined uncertainties

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				materialising simultaneously.
9.2.2	224	Impact of Inga delay	The description of the first sensitivity case (S1 - Inga delayed) suggested that the model has perfect foresight and other hydro projects were built because Inga was delayed. It is more likely that the delay not only has a cost implication but would also result in stunting all similar investment. This limitation should be stated in the report.	There is no foresight in the way the model works. The additional thermal capacity to compensate for 'no Inga' is developed towards the end of the planning horizon – 2033-2039 for CCGT gas in Mozambique and 2036-2039 large scale coal in South Africa. Don't quite agree (probably through mis-understanding) why delayed Inga would 'stunt' other investments – a political economy implication? Inga is in a class of its own, we do not think that attitudes about other projects would be unduly influenced by Inga's fate.
		Cahora Bassa	How come Cahora Bassa at $788/kW is not selected even with delays to Inga? Why does it rather get selected when hydrology is poor? In future consultations with countries policy makers, we will need solid reasons for what is included and what is not, to be able to push back.	The comparably low energy (GWh) contribution of HCB North Bank is the most probable reason why it does not get selected. For the low flow case, the energy on the existing HVDC from Songo and on the STE grid is less, so HCB NB can be

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				accommodated. With normal hydrology, a transmission upgrade would add to the costs of the HCB NB option, so this makes it a less attractive option for the algorithm to choose.
9.2.3	225	Dry climate scenario should renamed	Let's describe SC2 as testing Inter-annual variability (which is independent of climate change) instead of saying it is a test of the impact of climate change which is a far more extensive exercise.	Agreed that SC2 is not a full scale climate change investigation. But as the scenario basically tests the impact of low hydrological inflows throughout the planning period, 'dry climate' seems a more reasonable label rather than inter-annual variability.
9.2.4	227	Import cap in South Africa	The report indicates that imposing an import cap of 2800MW on South Africa proves infeasible but no explanation is given. Could this be due to transmission constraints? This needs some investigating and reporting.	Reference to 'infeasible' was in relation to how this sensitivity test was modelled. "It was implemented instead as a 'soft' constraint, whereby a violation does not make the model infeasible, but causes penalization instead (similar to the approach adopted for unserved energy)". No statement was being made to the effect that it would not be feasible for South Africa to impose such a constraint.

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9.2.5	228	Modelling of High RE scenario	It is not clear how the high renewables case (S4) was modelled. It would be helpful to clarify whether it was done as a constraint or by reducing capital costs or through some other method.	The renewables in S4 have been included as a policy decision i.e. they are treated as committed units within the model. The optimization algorithm comes in (via the medium term model) to determine how the extent to which the renewable plants will be used to meet energy demand.
6	106	Load flow studies for components A, B and C:	For the power flow studies in Chapter 6 - Country Transmission Plans, the scenarios are a bit inconsistent. How do the individual country transmission plans compare with Scenarios B and C for example? A table to show the changes (even in the annex) will be helpful. In addition, for the case for the sensitivity analysis, it would be useful to also have power flow studies for some of the cases studied (for example, impact of dispatch changes in the Dry Climate case on line loadings).	Section 6 presents results of Component A, but includes tables presenting transmission lines that are seen as required early on also in Component B and C. Optimisation of future transmission investments that may be dependent on the generation expansion plan is presented in Section 7. Comments clarifying this have been included in the report. Tables in Section 7 give the overall picture for all three components. No specific load flow studies have been made for the sensitivity scenarios. The same transmission candidates and

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				transfer limits are used. The energy flow on the selected candidates (per year and in both directions) are presented as part of the PLEXOS results.
5.3	102	Strengthening the regional overview of transmission - A lot of work seems to have been done for the transmission studies but the reporting undermines this effort. The results at the regional level (section 5.3) could be strengthened to answer some of the example questions in the next column.	a) Are there any critical voltage violations or congestion in any years? b) Are losses acceptable or exceptionally high? c) How much reactive power compensation is needed? d) How do the line loadings change if the dispatch changes or some of the major generation projects are delayed? e) How does the system behave with the loss of any of the HVDC lines under peak conditions? f) Should HVDC lines have additional termination points? g) What happens if grid investments in an intermediate country are delayed? Can long HVDC lines say from Inga to SA that do not terminate in any country be an option? h) A second HVDC line: Will a second HVDC line from Inga to South Africa through Namibia	The presentation in Section 5.3 as well as parts of Sections 6 and 7 have been expanded to shed light on these issues. The presentation of sensitivity tests in Section 9 has also been expanded to reflect in some more detail the impact on transmission projects. Further details on some of the questions should be studied at feasibility level.

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			and/or Botswana with a possible termination in Namibia or Botswana make economic sense (assuming Inga materializes or course and matched by adequate demand)? This will improve reliability.	
10.2	235	Real Options Analysis	The real options analysis is a powerful tool given the uncertainties in demand and generation and we look forward to the final analysis. In Table 51: why is stage 2 of Concept 3 triggered at t=0? Does this mean it is expanded at the start? What is the option in that case?	The option is to double the capacity of the line at any point in time starting from 2033. The results under this scenario (Scenario 3&4) reveal that the highest NPVext can be achieved if the capacity of the line is doubled in 2033 (i.e. @t=0).
C. OTHER COMMENTS (some moved to other sections)				
3.1 & 3.3	31 & 41	Inconsistency in values for NPV of investment costs	Please check the values in Page 41 since it isn't inconsistent with Table 8.	Revised figures, which include the cost of unserved energy, have been checked and hopefully all is now consistent.
3.1 & 7.1	31 & 190	Inconsistency in NPVs of transmission costs	In Section 7, the tables for the transmission expansion plan in each country has been presented. If you look at Figure 104 in Page 190 for Angola, the total investment costs are 898M USD, 1195 USD and 1195 USD for Component A, B and C. How does this figure add up and	The transmission investment costs in Table 8 reflect only the cross-border regional interconnections and a few regional transmission projects like the STE grid in Mozambique. These costs are part of the simulation in PLEXOS.

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			compare with the Table 8 in Page 31? Are the values in Table 8 only for the cross-border regional interconnection lines? What does "PV" stand for?	The tables in Section 7 are totals including 'domestic' projects as well as 'regional' projects. 'PV' in tables in Section 7 are 'present values'.
10	233	Benefits of regional transmission corridors noted	In Section 10, the economic analysis and cost-benefit analysis for selected regional transmission corridors have been performed which clearly showed the benefits of the regional transmission corridors.	These findings have been given more prominence in the final version.
7.1	188	Ensure clarity in use of 'thermal limit' and 'transfer limit'	We shouldn't confuse thermal limit with the transfer limit (For example in the sentence we say transfer instead of thermal: *The transfer limit on the first line is set at a modest 300 MW to ensure that the frequency response of the system is acceptable following a loss of the line*)	Indeed. The thermal limit of many (most) transmission lines is significantly higher than the transfer limit. Transfer limits are typically also set for boundaries consisting of two or more lines, and may be limited by transient stability, steady state voltage stability etc. more often than thermal limits.
11	241	GIS database – add a recommendation	What will the consultant suggest on how SAPP maintains the database? Does the tool include characteristics of lines and generators?	Further training will be required to ensure that the SAPP GIS database is maintained. Full characteristics of lines and generators are in the PLEXOS database.

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		EXECUTIVE SUMMARY		
Exec Sum		In-text corrections to the Executive Summary	Mainly typos and inconsistencies in numbers between text and tables	Corrections have been made.
4	2	the total regional demand takes account of diversity arising from the non-coincidence of country peaks	I am not clear what this means. Is it that each country hits peak power at different times of day? Or that it is unlikely that each country will reach forecasted demand so the aggregate is reduced?	Yes, it refers to each country hitting peak demand not just at different times of the day, but different days of the year. So the peak demand for the regional system as a whole is less than the sum of the national peak demands. The size of the divergence being larger at the end of the period than at the beginning, this being due to the reduced dominance of South Africa and the inclusion of newly connected utilities in different time zones to the present SAPP core countries.
14	13	Recommendation on improving demand forecasts	Are the demand forecasts likely to improve? Can you use different analytical techniques to get around uncertain demand projections?	Proposals have been made for ECA to provide training in demand forecasting.