SAPP POOL PLAN 2017

Executive Summary

SAPP

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01 POOL PLAN OBJECTIVES

The objectives of the 2017 SAPP Pool Plan are to "identify a core set of generation and transmission investments of regional significance that can provide adequate electricity supply to the region under different scenarios, in an efficient and economically, environmentally and socially sustainable manner and support enhanced integration and power trade in the SAPP region."

The Pool Plan (PP) incorporates the SAPP Generation Planning Criteria published in 2011. The ***security criterion*** requires the minimum level of generation capacity to be equal to or greater than 100% of demand. The ***reliability criterion*** defines the reserve capacity obligation (10.6% of annual peak demand for predominantly thermal systems and 7.6% for mainly hydro systems and weighted average for mixed systems). SAPP permits the Reliability Criterion to be met through a country contracting reserve auxiliary services from others.

02 UNIQUE APPROACH

The conventional approach in a regional power sector master plan is to treat the interconnected region as though it were a single country and use optimisation planning software to derive the least cost generation and transmission investment sequencing. However, an economically optimal regional plan is often not optimal from an individual country perspective due to other important non-cost factors.

In this study, there are 3 principal case studies or components, with the third bringing in the factors of importance from individual country perspectives:

- **Component A / Benchmark Case –** This is a combination of country-by-country expansion plans based on national master plans extended (where necessary) to 2040 with a consistent set of assumptions. The results of this component are driven by two important assumptions: a large proportion of the generation options are defined by the countries as "committed", and trade is limited by the only new transmission interconnectors allowed being those already under construction.

- **Component B / Full Integration Case –** This is the full optimisation case whereby the region is treated as though it is a single country and a least cost sequence of generation and transmission expansion projects is derived.

- **Component C / Realistic Integration case –** This is an intermediate integration case, whereby certain constraints are applied to Component B to ensure that each country, at a minimum, fulfils SAPP security and reliability planning criteria. This was interpreted to mean that by 2040 each country should have sufficient installed or firm imported capacity to be able to meet its maximum demand and reserve obligations, and large thermal power plants should operate at or above minimum capacity factor levels.

03 SPATIAL MAPPING OF ENERGY RESOURCES

Another innovative feature of the 2017 Pool Plan is the introduction of spatial mapping using a Geographic Information Systems (GIS) approach. This has two areas of focus in the study, the first being the spatial representation of all relevant power generation, transmission and load centre information, and the second being to provide the database of spatial and non-spatial data for use by the member states within the Rapid Impact Assessment Matrix Tool (RIAM) for Environmental and Social (E&S) Sustainability analysis.

The use of RIAM is demonstrated in the Pool Plan through its use in screening generation and transmission projects. The tool is well suited to assessing transmission projects with the level of resolution that was possible with the data that could be assembled during the study.

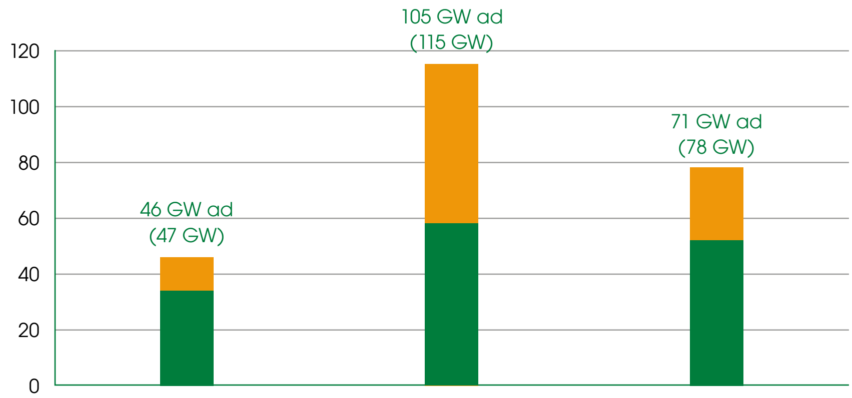
One project (Mupata Gorge) was removed from the candidate project list after screening. Following an iterative process to define transmission line corridors, none of the proposed routes directly impacts on a no-go area. A small number (3–4) of generation projects in national plans are in sensitive areas.

04 DEMAND FORECAST

The main demand forecasts for each country were based on the national forecasts supplied by the utilities, extended where necessary to 2040, with subsequent modifications being discussed and agreed with the utilities. The main forecast is considered to be on the high side, and for the sensitivity analysis a 'low' demand forecast was developed. This was again based on considering each country separately, adopting existing 'low' forecasts where these were available, or assessing the possible 'low' outcomes of risk factors in relation to key demand drivers. In some cases, lower initial levels of unmet demand were assumed, and/or slower economic growth and less rapid increases in electrification rates.

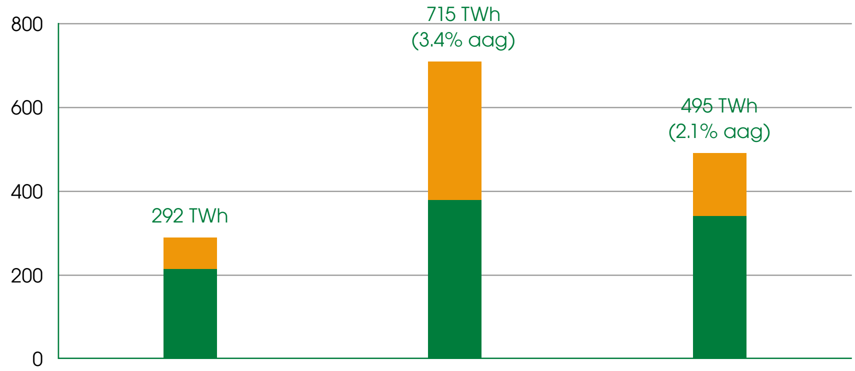
There are two important differences to note when comparing the forecasts in this report to those done previously: the demand of each country is highlighted without reference to how this is supplied and the total regional demand, which takes account of diversity arising from the non-coincidence of country peaks, is less than the sum of the national peak demands.

SAPP peak demand growth – base and low demand projections



	Maximum demand in 2016, GW	Maximum demand in 2040, GW – Base	Maximum demand in 2040, GW – Low
Rest of SAPP	13	55	26
South Africa	34.0	58.2	52.4

SAPP energy sent out – base and low demand projections



	Energy sent out, TWh (2015)	Energy sent out, TWh (2040) – Base	Energy sent out, TWh (2040) – Low
Rest of SAPP	76	319	151
South Africa	216	382	344

The aggregate forecasts of demand in GW and energy in TWh are shown in the diagrams above (note that aag = annual average rate of growth and ad = after diversity, 1.03 in 2015 and 1.10 in 2040). For the demand forecasts, figures for the direct addition of the maximum demand in each country are shown together with after diversity demand (factor of 1.03 assumed to increase to 1.10 in 2040 with the declining share of South Africa in SAPP and the introduction of new connected members).

05 COUNTRY PLANNING STUDIES

As mentioned above, national power system master plans are the basis for the Pool Plan, particularly Component A, with extensions of the candidate generation projects for B and C, which at the same time open up the transmission options.

With the exception of Namibia there are no explicit country policies for regional trade in electricity. In line with the SAPP criteria, countries plan to be self-sufficient in capacity from own generation resources to match maximum power demand and reserve obligations. Namibia states that "it is the aim of government that 100% of the peak demand and at least 75% of the electric energy demand will be supplied from internal sources by 2010".

Some of the more common reasons for the inward focus of the country plans are:

- Importing countries have suffered more than exporting countries during recent periods of power shortages.
- There are no guarantees that the generation development of each country will proceed as planned.
- There is no price transparency and therefore imports may not be advantageous in terms of cost for countries with no alternative options.
- The need to develop local industry and skills.

Observations from the analysis of the country master plans helped to inform the assumptions used to develop the realistic integration and sensitivity scenarios.

06 FUEL AND TECHNOLOGY PRICES

Fuel prices (US$/GJ) and unit investment costs ($/kW) used in the generation optimisation model were obtained from international sources (details are given in the main report).

Fuel type	2017	2030	2040
Gas (domestic)	2.6	3.3	3.9
Gas (LNG netback)	9.1	11.5	13.7
Coal (domestic)	2.5	2.7	3.0
Coal (Malawi)	3.1	3.4	3.7
Crude oil (reference)	8.1	14.8	16.5
Uranium	1.4	1.4	1.4
Diesel	10.7	19.5	21.8
HFO	7.3	13.3	14.9

Technology		$/kW	Technology		$/kW
Gas:	OCGT	795	Hydro:	Small	4,000–4,200
	CCGT	1,014		Large	3,000
	ICE engines	1,086	Solar:	CSP	3,987
Coal:	Subcritical	2,264		PV	990
	Supercritical	3,739	Wind		1,720
	IGCC	5,779	Biomass		4,060
			Nuclear		6,137

07 LIMITATIONS OF THE METHODOLOGY

At the heart of the methodology used in the study is a powerful optimal planning tool (PLEXOS). The results should not, however, be construed as being "optimal" due to a number of practical limitations, first and foremost being data made available for the PP study being of variable accuracy and completeness.

Data limitations and consistency affected all the major elements of the study, from the demand forecasts, through generation and transmission planning. There are particular difficulties in respect of load profile data, absence of dynamic PSS/E files and the general assumptions that had to be made about renewables.

SAPP considers the Pool Plan as an ***indicative*** rather than a ***prescriptive*** plan. This is appropriate, because the planning of generation and transmission expansion over the power systems of 12 countries is always going to have limitations. Fortunately, the accuracy of the numerical results is not as important as the insights that the modelling process gives into the opportunities for countries to benefit from incorporating a greater degree of regional integration into their national master plans.

CSP Concentrating Solar Power / **CCGT** Combine Cycle Gas Turbine / **HFO** Heavy Fuel Oil / **HVAC** High Voltage Alternating Current / **HVDC** High Voltage Direct Current

08 COMPARISON BETWEEN COMPONENTS A, B & C

The objective function in the optimisation is to minimise investment costs (overnight capital costs discounted from the year of commissioning), short-term operational costs (fuel and O&M costs), plus the cost of unserved energy (calculated at a notional cost of $1,000/MWh) using a social discount rate of 6%.

The NPV of the total costs is the main indicator that can be used to rank the three Components. The "headline" values are shown in the tables below ($ refers to US$, b = billion).

$b / GW differences	**Component**			**B<>A**	**C<>A**	**C<>B**
	A	**B**	**C**			
Investment costs ($ b)	155	117	121	-38.1	-34.3	3.8
of which – generation	*154.2*	*113.5*	*117.7*	*-40.6*	*-36.5*	*4.1*
– transmission	*1.1*	*3.6*	*3.3*	*2.5*	*2.2*	*-0.3*
Short-term operational costs ($ b)	128	123	125	-4.1	-2.9	1.2
Unserved energy (UE) cost ($ b)	12	13	13	1.7	1.5	-0.3
Installed generation capacity (GW)	143	127	130	-17	-14	3
SAPP w/o UE ($ b)	283	241	246	-42.2	-37.2	5.0
SAPP with UE ($ b)	294	254	259	-40.5	-35.7	4.8

% differences	**Component**			**B<>A**	**C<>A**	**C<>B**
	A	**B**	**C**			
Investment costs ($ b)	155	117	121	-25%	-22%	3%
of which – generation	*154.2*	*113.5*	*117.7*	*-26%*	*-24%*	*4%*
– transmission	*1.1*	*3.6*	*3.3*	*228%*	*198%*	*-9%*
Short-term operational costs ($ b)	128	123	125	-3%	-2%	1%
Unserved energy (UE) cost ($ b)	12	13	13	15%	13%	-2%
Installed generation capacity (GW)	143	127	130	-12%	-10%	2%
SAPP w/o UE ($ b)	283	241	246	-15%	-13%	2%
SAPP with UE ($ b)	294	254	259	-14%	-12%	2%

Component B, the idealised Full Integration Case, is clearly superior to Component A, the Benchmark Case. To meet the demand forecast, only 127 GW of installed capacity is needed in B as compared with 143 GW in A. There is a significant saving in investment costs, plus a small saving in operational costs, leading to overall savings of $41 b (14% of the total costs of Component A).

Component C introduces restrictions which makes it a more "realistic" approach to regional integration: installed capacity has to be equal or above maximum demand by 2040, and large thermal plants are required to operate at or above minimum capacity factors.

ICE Internal Combustion Engine / **LNG** Liquified natural gas / **NPV** Net Present Value / **OCGT** Open Cycle Gas Turbine / **PV** Photovoltaic

In comparing Components B and C, what is significant from the above tables is that the realism restrictions do not make C much more expensive than B. In relation to the Benchmark Case, the Realistic Integration case delivers almost the same cost savings as the Full Integration case, while being much more acceptable as a basis for national planning.

Installed capacity in 2040 in C is 130 GW, only 3 GW higher than B and still 14 GW lower than A. The overall cost of C is $259 b, only $5 b higher than B but still $36 b (or 12%) lower than the total cost of A.

This is a satisfying finding of the study in that it shows that the imposition of the 'realism' constraints on the idealised full integration case involves only a limited cost, which does not significantly dilute the benefits of regional power sector integration. At the individual country level, highlights of which are in the attached Annex 1, the least cost regional plan allows the countries to fulfil the SAPP security and reliability criterion through a combination of local generation and firm imports.

Another important finding that emerges from the above tables is that the cost of transmission interconnectors is only a small fraction of the generation investment costs. On an NPV basis, in Component C investment costs are only $3.3 b out of total investment of $121 b, or less than 3%. There is thus a strong case to prioritise regional interconnector investments, which create opportunities for flexible responses to the out-turn of uncertainties, as well as generally making an important contribution to strengthening national transmission grids.

09 MAJOR GENERATION PROJECTS

The Pool Plan results are driven by key projects of regional significance. These are the major hydropower projects – thermal projects play an important supportive role, but are not drivers of regional integration in the same way.

The tables below list the key generation projects, indicating the years in which they are to be commissioned in the different Components. The biggest single generation complex is at Inga, where 11,654 MW of new capacity is to be installed by 2040 in both Component B and Component C.

Hydropower project	Component A	Component B	Component C	Comments
Camambe II (Angola)	700 MW in 2017	700 MW in 2017	700 MW in 2017	Angola is an exporter in the early part of plan period. Rapid demand growth results in net imports by 2040.
Lauca (Angola)	2,004 MW in 2017	2,004 MW in 2017	2,004 MW in 2017	
Caculo Cabaça (Angola)	2,160 MW in 2022	2,160 MW in 2022	2,160 MW in 2022	
Batoka (Zambia and Zimbabwe)	2,400 MW in 2023	2,400 MW in 2023	2,400 MW in 2023	Zambia aborbs the capacity through rapid growth, Zimbabwe becomes an exporter.
Devil's Gorge (Zambia and Zimbabwe)	1,200 MW in 2025	1,200 MW in 2033	1,200 MW in 2032	

Hydropower project	Component A	Component B	Component C	Comments
Mphanda Nkuwa (Mozambique)	1,500 MW in 2025	1,500 MW in 2025	1,500 MW in 2028	Key project, together with gas and coal, of Mozambique being a major exporter.
Cahora Bassa North Bank (Mozambique)	1,245 MW in 2026			This project is committed in A, but not chosen in B and C.
Inga 3&4 (DRC)	4,800 in 2020 15,366 MW in 2030	4,800 in 2030, 9,427 MW in 2033, rising yearly to 11,654 MW in 2036	4,800 in 2030 9,426 MW in 2032, rising yearly to 11,654 MW in 2034	DRC becomes a major exporter once Inga is developed.
Stiegler's Gorge (Tanzania)	1,048 MW in 2025 2,096 MW in 2037	1,048 MW in 2038	1,048 MW in 2036 2,096 MW in 2039	Hydro complements TZ's big investments in gas and coal.

10 MAJOR TRANSMISSION PROJECTS

Transmission studies for all cases assume that all internal projects necessary to integrate new generation projects are committed and therefore the focus is on identifying required interconnectors and their transfer limits. Transfer limits are conservatively set at peak demand. In the benchmark case new interconnectors were limited to three – Zimbabwe-South Africa portion of MOZISA, Zimbabwe-Zambia portion of ZIZABONA and Zambia-Tanzania interconnection from Kabwe to Mbeya. The focus of the study in the benchmark case was therefore confined to verifying that the national plans meet the agreed SAPP planning criteria and to note the trading bottlenecks.

Subsequent regional integration scenarios then remove the bottlenecks to facilitate trading of surpluses. The objective is to identify a least-cost development path which balances investments, losses, O&M and cost of supply interruptions. Because both technical and economic criteria are considered, some unserved energy is allowed if that is more economic than eliminating it.

Transient stability is tested for three phase faults cleared within 100 ms. In the absence of information on hydro power plants, generic models were used although this is not altogether satisfactory, as hydro plant characteristics are very much site-specific depending on inertia of machines, head and waterways.

The Pool Plan study has indicated that Angola and Malawi should be integrated into SAPP early on. The following interconnections are therefore clearly recommended for early development:

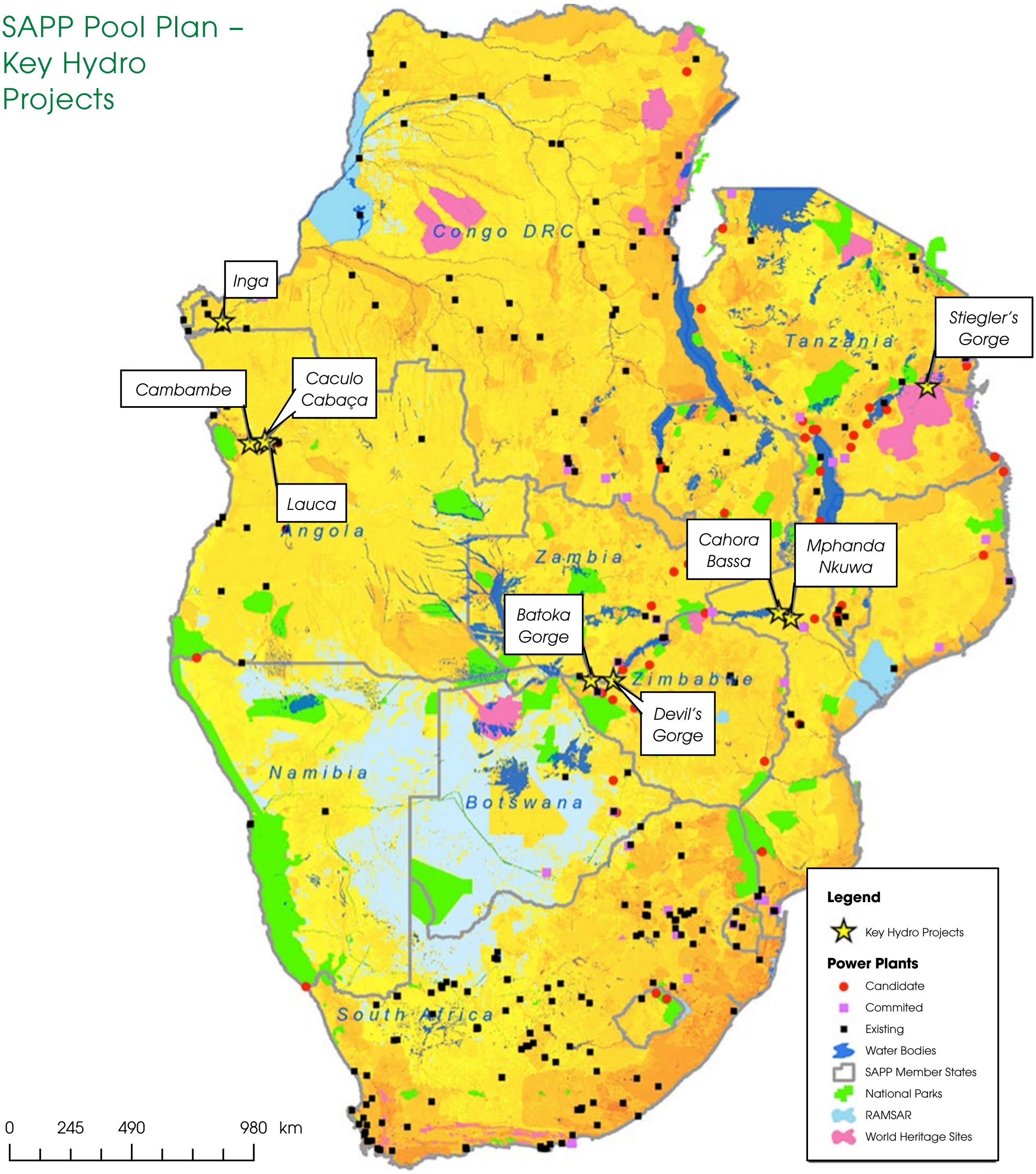
- N'Zeto/Angola – Inga/DR Congo
- Cahama/Angola – Kunene/Namibia
  Possibly via Baynes if a decision to implement this project is firmed up.
- Matambo/Mozambique – Phombeya/Malawi

ICE Internal Combustion Engine / **LNG** Liquified natural gas / **NPV** Net Present Value / **OCGT** Open Cycle Gas Turbine / **PV** Photovoltaic

The addition of Batoka by 2023 can be supported by existing and already committed transmission projects. When Mphanda Nkuwa is added in 2028 (in Component C), the STE project in Mozambique will have to be in place. The existing MOTRACO system linking South Africa and the southern part of the grid in Mozambique along with the existing DC link from Songo to Apollo and also the link from Songo to Zimbabwe would provide adequate capacity for trade with other SAPP members for some time once the STE backbone grid is in place. The STE grid therefore provides additional capacity for regional trade.

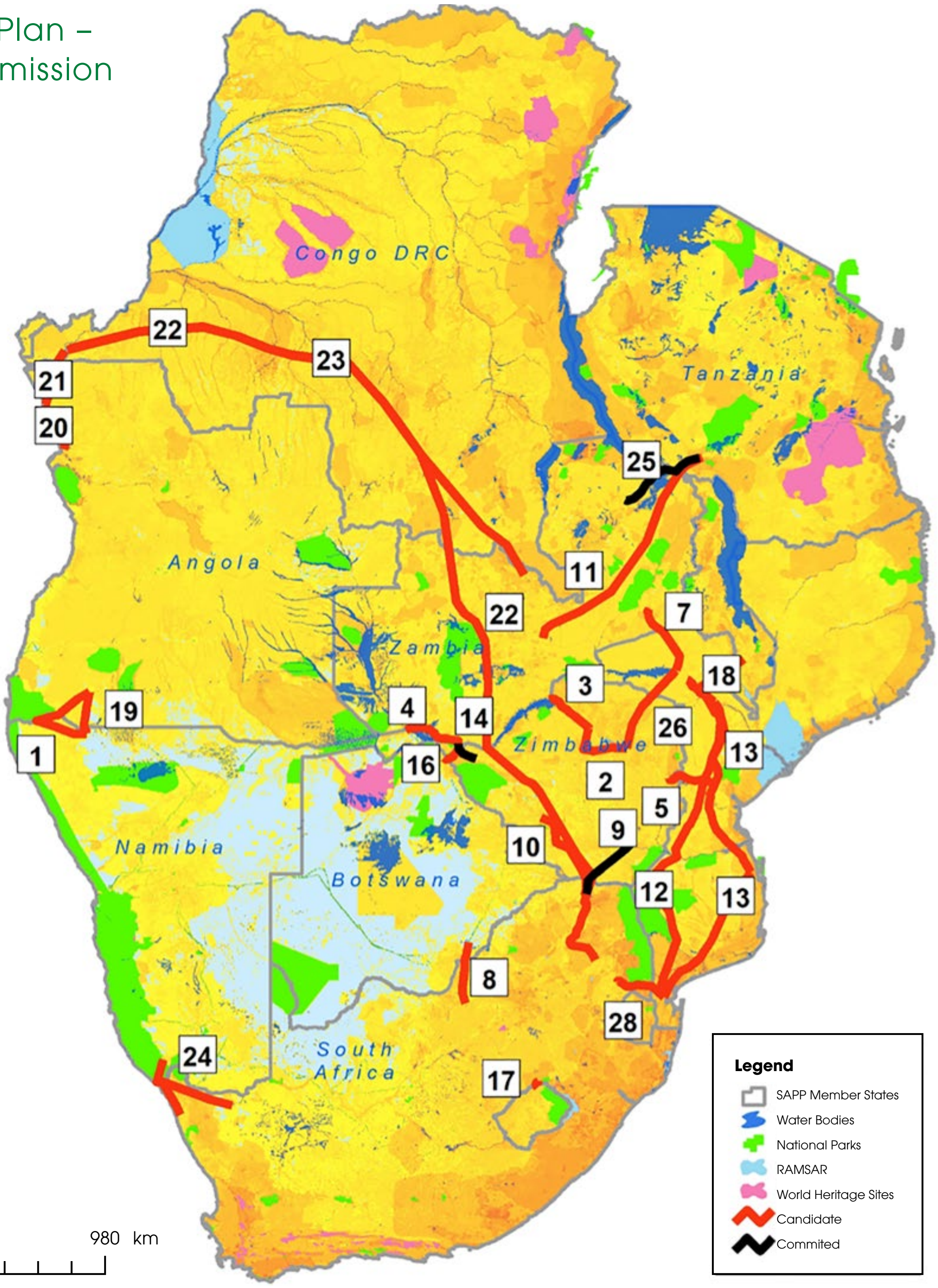
The largest hydropower project by far is Inga, which is also the most remote from the centres of demand that it has the potential to serve (as shown on the map overleaf). The development of Inga therefore needs to be supported by major transmission line projects, which are listed in the table below, together with details of the STE project.

SAPP Pool Plan – Key Hydro Projects



Transmission line	Characteristics	Component B	Component C	Utilisation in 2040
Inga-Angola	3 x 400 kV HVAC	1,100 MW in 2023 (i.e. two lines) 1,600 MW in 2033 (with third line)	1,100 MW in 2020 (i.e. two lines) 1,600 MW in 2034 (with third line)	14 TWh (Full load)
Inga-Luano (Zambia)	500 kV HVDC	2,000 MW in 2030	2,000 MW in 2029	10.7 TWh (61%)
Inga-Limpopo (Gauteng) (SA)	600 kV HVDC	3,000 MW in 2033	3,000 MW in 2032	26.4 TWh (Full load)
Kabwe (Za) – Mbeya (Tz)	500 kV HVDC	1,500 MW in 2030		
STE (Mozambique)	1 x 400 kV HVAC north to central 1 x 400 kV HVAC central to south 500 kV HVDC bi-pole line, first stage only on converters	In 2023, to cover local demand in Beira In 2027, providing 400 MW capacity north to south In 2027, 1,325 MW	In 2023, to cover local demand in Beira In 2028 , 400 MW capacity north to south In 2028, 1,325 MW	

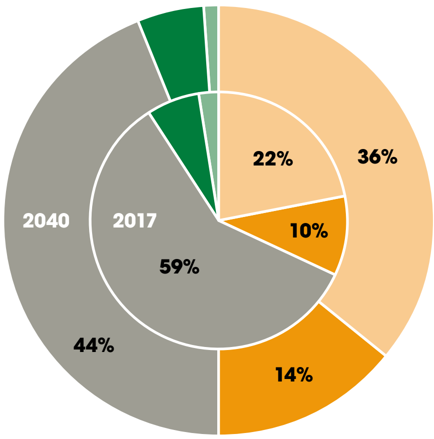
SAPP Pool Plan – Main Transmission Corridors



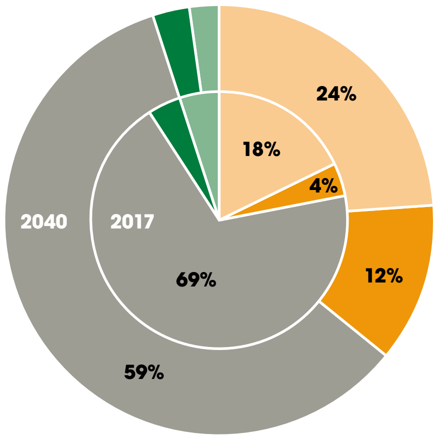
11 GENERATION SHARES BY TECHNOLOGY

The diagrams on this page show the shift towards energy from hydro in Components B and C, which incorporate the interconnectors from the Zambezi hydro projects and Inga.

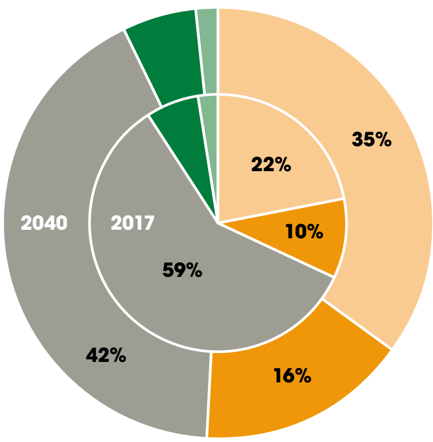
Component A installed capacity (MW)



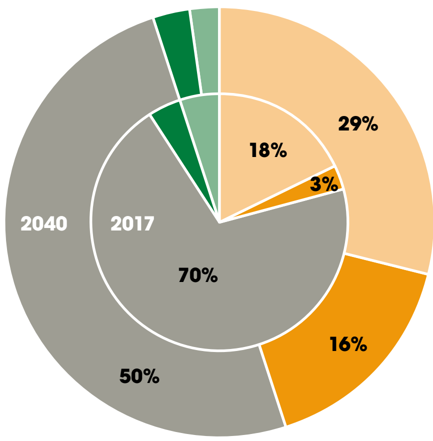
Component A energy (GWh)



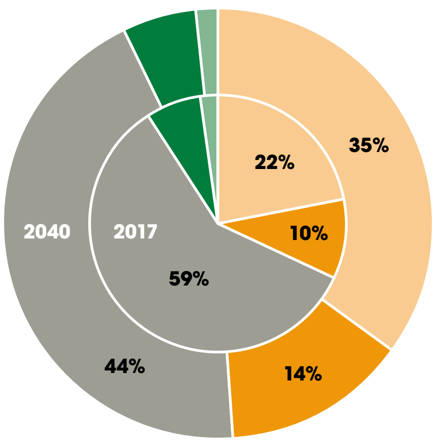
Component B installed capacity (MW)



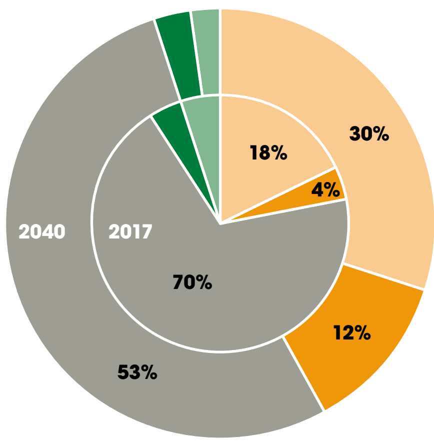
Component B energy (GWh)



Component C installed capacity



Component C energy (GWh)



- Hydro
- Thermal (ex. Coal)
- Coal
- Renewables
- Nuclear

12 AVERAGE SHORT-RUN ELECTRICITY PRICES ACROSS SAPP

Average short-run prices across the SAPP region for Component C are shown in the table below. These are load weighted prices, which are the costs to the consumer divided by the consumer demand. In the italicised years, the costs are raised by the presence of unserved energy, which is valued here at the same price used elsewhere in the report of $1,000/MWh. For the other years, the figures are the average short-run generation costs, and these are low (between 2.7 c/kWh and 4.7 c/kWh).

Average electricty prices for Component C ($/MWh and c/kWh)

Units	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	2023	2024	2025	2026	2027	2028
$/MWh	*140.6*	*130.5*	*50.5*	*28.9*	*28.9*	*28.2*	26.7	28.5	30.0	30.1	32.6	35.3
$c/kWh	*14.1*	*13.1*	*5.0*	*2.9*	*2.9*	*2.8*	2.7	2.9	3.0	3.0	3.3	3.5

Units	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	2035	2036	2037	2038	2039	2040
$/MWh	*37.0*	*46.7*	*36.8*	*31.8*	*31.7*	*35.2*	35.8	36.9	40.0	41.7	40.1	56.2
$c/kWh	*3.7*	*4.7*	*3.7*	*3.2*	*3.2*	*3.5*	3.6	3.7	4.0	4.2	4.0	5.6

Low electricity prices have in the past given the SAPP region a comparative advantage in the costs of production, particularly of energy-intensive mineral products. If Component C is followed, the above short-run costs will be an important element of keeping the average prices of traded electricity low into the future.

13 SENSITIVITY TESTS

Two sensitivity tests were carried out on Component A, the first (SA1) being to limit "committed" plants to those already under construction or which have reached financial closure, the second (SA2) being to use in addition the "low" demand forecast.

Componednt A sensitivity tests	Component A	S A1 – Restricted committed	S A2 – Restricted committed + low demand
Investment costs ($ b)	155.3	124.7	95.0
Short-term operational costs ($ b)	124.7	127.8	107.9
Unserved energy cost ($ b)	11.5	13.9	6.1
Installed capacity (GW)	143.4	129.2	100.1
SAPP total ($ b)	291.5	266.4	209.0

ICE Internal Combustion Engine / **LNG** Liquified natural gas / **NPV** Net Present Value / **OCGT** Open Cycle Gas Turbine / **PV** Photovoltaic

The NPV results in the table show that creating greater flexibility by removing the requirement that almost all projects are "committed" allows significant cost savings to be made in investment costs. This is slightly offset by higher operational costs as more energy is derived from thermal units than in the base Component C, but there are still savings overall amounting to 10% of the costs of Component A ($28 b).

Sensitivity SA1 produces a scenario that is not greatly different, at least in aggregate terms, to Component C. The installed capacity by 2040 is only 1 GW different, and the total NPV difference is also relatively small (NPV of SA1 is $266 b, NPV of Component C is $259 b). There are larger differences at the national level, however.

When low demand is added to the restricted committed list, the total costs fall dramatically (from $292 b to $209 b, a reduction of 28%). A much lower level of capacity (100 GW) is required to meet the lower demand, so investment costs fall by 39% while operational costs decrease by 14%.

The main NPV results for the Component C sensitivity tests are given in the table below (in billions of $), together with the total installed capacity in 2040 (in GW).

Component C sensitivity tests	Component C	SC1 – Delay	SC2 – Dry C	SC3 – SA import cap	SC4 – High renewables	SC5 – Low demand
Investment costs ($ b)	121.0	118.9	121.3	126.6	139.9	86.6
Short-term operational costs ($ b)	124.7	128.5	130.2	125.1	116.4	107.1
Unserved energy cost ($ b)	13.0	13.0	24.4	13.0	13.0	6.1
SAPP total ($ b)	258.6	260.4	275.9	264.7	269.3	199.8
Installed capacity (GW)	129.6	127.5	132.5	132.0	157.2	95.4

- SC1 tests the impact of a delay in implementing large regional investment projects, specifically Inga. Impact is an increase in total costs of only $1.8 b (0.7%).
- SC2 tests the impact of climate change that results in 'dry' conditions which impact on the availability of energy from hydro stations. Impact is an increase in total costs of $17.2 b (6.7%), a large portion of this ($11.4 b) being the costs of additional unserved demand.
- SC3 tests the impact of South Africa imposing an import cap of 2,800 MW. Impact is an increase in total costs of $6.0 b (2.3%).
- SC4 tests the impact of SAPP countries implementing a policy of high renewables, matching the level posed in the 2013 IRENA report. Impact is an increase in total costs of $10.7 b (4.1%).
- SC5 tests the impact of low demand. As was the case in SA2, the impact of low demand is very significant, resulting in a reduction in total costs of $59 b (22.8%).

The sensitivity tests involving the base demand indicate that Component C, the Realistic Regional Integration case, is robust in the face of the risk factors and policy changes analysed. While the impact for the SAPP region as a whole is quite limited, there are significant changes for individual countries. In particular, Mozambique emerges as a 'buffer' country, absorbing the implications of various uncertainties being resolved largely through big changes in CCGT capacity.

If the lower demand forecast were to materialise, member states would be able to delay investment plans, which would reduce the pressure to raise the enormous level of financing required for the base Component C. Projects such as Devil's Gorge, Maamba Coal II, Inga 3, Inga 4 and Stiegler's Gorge are no longer selected within the 2040 planning horizon.

An alternative Component C was developed to take account of requested changes in the candidate project lists in Botswana, DRC, Mozambique and eSwatini. The NPV and installed capacity results for the alternative Component C are little different to the original, but there are some significant changes at the country level, particularly in Mozambique.

MW in 2040	Component A		Component C		Alternative C		Alt C – Original C	
	New Gen	% thermal	New Gen	% thermal	New Gen	% thermal	New Gen	
Angola	10,428	29%	8,303	10%	8,303	10%	0	0%
Botswana	582	83%	1,400	100%	882	89%	-518	-11%
DRC	21,806	2%	17,664	3%	17,407	3%	-257	0%
Lesotho	275	0 %	275	0 %	275	0 %	0	0%
Malawi	4,203	64%	3,882	59%	3,882	59%	0	0%
Mozambique	5,910	49%	6,060	71%	7,480	50%	1,420	-21%
Namibia	1,225	76%	1,000	70%	1,000	70%	0	0%
South Africa	20,133	92%	11,958	86%	11,958	86%	0	0%
eSwatini	132	0%	432	69%	432	69%	0	0%
Tanzania	15,010	69%	14,602	74%	14,302	76%	-300	2%
Zambia	4,007	15%	5,269	35%	5,269	35%	0	0%
Zimbabwe	4,680	54%	3,770	44%	3,720	43%	-50	-1%
SAPP	88,391	48%	74,615	47%	74,910	45%	295	-2%

14 REAL OPTIONS AND ECONOMIC ANALYSIS OF TRANSMISSION CORRIDORS

The costs of the regional inter-connectors are a small proportion (~3%) of total capital costs, but it is through the construction of these interconnectors that the significant reductions in overall NPV take place, primarily through reducing generation investment costs but also through lower operational costs.

Using the costs savings from C (including net costs of unserved energy) as compared with A as the measure of benefits, the overall benefit:cost ratio of the transmission interconnectors is 16.4. However, the requirement that most generation projects be considered committed is a somewhat artificial assumption, which is removed in sensitivity SA1. Using the cost savings from C

ICE Internal Combustion Engine / **LNG** Liquified natural gas / **NPV** Net Present Value / **OCGT** Open Cycle Gas Turbine / **PV** Photovoltaic

as compared with SA1 as a more appropriate measure of the benefits of opening up the regional transmission system, the benefit:cost ratio for regional interconnectors is calculated to be 3.3.

The underlying economics of regional transmission projects is reinforced by the Real Options Analysis (ROA). This demonstrates that, for the largest of the interconnector projects, there are no savings to be made from staging the investments. Even in the face of reduced demand or delay in implementing the capacity expansions at Inga, the ROA shows that the HVDC line from Inga to Gauteng should be built to its full capacity from the outset. On the other hand, in the case of the Inga-Angola HVAC lines, the ROA indicates that only the first 2 phases should be built at once, with a decision being made about the third phase at a later date when key uncertainties have been to some extent resolved.

To get an indication of the relative importance of different transmission lines, a simple test was carried out of removing each major line in turn from the network, while treating all other investments as sunk costs and re-optimising the energy despatch.

The line with the largest capacity (Inga-South Africa) has the highest absolute value of over $9 b, representing a 3.5% increase in costs which would be imposed were that line to be removed, but in the case of Inga-Angola the additional unserved energy gives a higher absolute value of $16 billion (6.2% increase in costs), most of which is the discounted cost of induced unserved demand ($13 billion).

The high cost of unserved energy results in Inga-Angola having by far the highest benefit:cost ratio (136.6). The line itself is short and the direct costs are therefore relatively modest, and having the line in place allows unserved energy to be minimised in Angola. In the other two cases, induced additional unserved energy is either zero or not significant. The benefit:cost ratio is higher for Inga-South Africa (8.7) than for Inga-Zambia (1.7): higher avoided costs in the South African case greatly outweigh the cost of the long, high capacity Inga-South Africa transmission line.

Transmission projects	Capacity lost	NPV of total costs (incl. UE costs)	Cost of line removal ($m)	NPV of costs transmission investment ($m)	Benefit: cost ratio	Induced unserved energy in 2040
Component C		$ 259 b				
Inga-Zambia removed	2,000 MW	$ 262 b	$ 1,215 m (0.5%)	$ 719 m	1.7	0 GWh
Inga-Angola removed	1,600 MW	$ 273 b	$ 16,114 m (6.2%)	$ 118 m	136.6	7,921 GWh
Inga-South Africa removed	3,000 MW	$ 269 b	$ 9,067 m (3.5%)	$ 1,048 m	8.7	311 GWh

The high level calculations above do not capture the full benefits of investing in the regional interconnectors. These projects will also provide significant local benefits to the countries involved through supporting local transmission grid development. Co-ordination of the grid expansion planning to meet local demand with the planning of regional inter-connections will likely lead to these projects being found to be viable at an earlier stage than is indicated in the Pool Plan.

15 CONCLUSIONS, RECOMMENDATIONS AND LESSONS LEARNT

The conclusions of the Pool Plan study are:

- **The Realistic Regional Integration scenario captures most of the regional integration benefits.**
- **Transmission interconnectors can safely be developed early in the planning period.**
- **The Realistic Regional Integration scenario is also robust.**
- **Changes in demand forecasts have the biggest impact on the level of generation and transmission investments.**

The Executive Committee of SAPP has endorsed Component C as the SAPP Pool Plan 2017.

SAPP recommends that:

- **2017 Pool Plan perspectives be incorporated into national power development planning.**
- **Implementation of the priority transmission and generation projects be advanced.**

A number of lessons have emerged from the process of formulating the SAPP Pool Plan 2017:

- **Improved and systematic *data collection* and *retention* within the utilities and SAPP Coordination Centre is necessary so that there are functional and updated databases form the start of future planning studies.**
- **More frequent and detailed reviews of *demand forecasts* are necessary, followed by updates of the generation expansion plans to meet the demand.**
- ***Methodologies used for demand forecasting* could usefully be harmonised across the region, with realistic assumptions on the key demand drivers.**
- **Continuous *training of staff* is needed in areas such as demand forecasting, collection and management of data, use of GIS and other planning tools.**

Transmission interconnector prioritisation is justified by the underlying economics of regional trade, bolstered by consideration of national grid reinforcement. Having grid interconnector capacity available also provides the opportunity for flexible solutions to be found as uncertainties are resolved over the course of the planning horizon.

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The high priority generation and transmission projects are summarised in the tables below.

Generation projects	Countries	Capacity and commissioning dates
Batoka	Zambia and Zimbabwe	2,400 MW in 2023
Mphanda Nkuwa	Mozambique	1,500 MW in 2028
Devil's Gorge	Zambia and Zimbabwe	1,200 MW in 2032
Inga 3&4	DRC	4,800 in 2030, 9,426 MW in 2032, rising yearly to 11,654 MW in 2034
Stiegler's Gorge	Tanzania	1,048 MW in 2036 2,096 MW in 2039

Transmission projects	Characteristics	Capacity and commisioning dates
Inga-Angola	3 x 400 kV HVAC	1,100 MW in 2020 (2 lines) 1,600 MW in 2034 (with third line)
Inga-Luano (Zambia)	500 kV HVDC	2,000 MW in 2029
Inga-Limpopo (Gauteng) (SA)	600 kV HVDC	3,000 MW in 2032
STE (Mozambique)	2 x 400 kV HVAC 500 kV HVDC	Phased development over 2023–2028

SAPP member countries will share in the benefits of pursuing the realistic regional integration approach. The main exporting countries in the Plan are DRC and Mozambique, both of which have the potential to make the export of electricity into a major foreign exchange earner.

In addition to the Annex below, further country-by-country information for each of Components A, B and C, and the alternative Component C, is available in the spreadsheet which accompanies this Executive Summary. Additional information on the assumptions made and details on the results are available in the Main Volume of the SAPP Pool Plan and the accompanying Annex Volume.

ANNEX 1 – SUMMARY RESULTS FOR EACH COUNTRY

Benchmark Case (Component A) compared to Realistic Integration Case (Component C)

Country	New Generation & Mix (Component A 2040) Thermal% / Hydro&Renewable%	New Generation & Mix (Component C 2040) Thermal% / Hydro&Renewable%	Transmission Developments
Angola	10,428 MW; 32/68 Reserve margin: 21%	8,303 MW; 18/82 Reserve margin: 0%	• Interconnection at 400 kV DRC-Angola & Angola-Namibia to export surplus in early years and import in later years. • Second North-South 400 kV line required by 2025; and third line in the 2030's to strengthen internal grid (highly dependent on domestic load growth as well as exports).

Botswana	582 MW; 92/8 Reserve margin: -14%	1,400 MW; 100/0 Reserve margin: >40%	• National network has radial 400 kV where further studies are required to confirm if loss of load and reactive compensation are acceptable when there are faults • To meet minimum capacity requirements Botswana becomes a net exporter which requires a strengthening of the interconnection to South Africa (Isang-Watershed)
Drc	21,806 MW; 3/97 Reserve margin: almost 300%	17,664 MW; 4/96 Reserve margin: >200%	• The 220 kV Katanga network is a bottleneck for transfer of power between DRC and Zambia. Beyond 2020 a second Inga HVDC link, terminating in Zambia, plus extra generation in the Katanga region required • Interconnections to Angola (400 kV), Zambia and RSA (both HVDC) are necessary to evacuate power if Inga 3 and 4 are developed according to recommended least-cost regional plan. Multi-terminal Inga-Zambia-RSA link is not recommended for the 5000 MW transfer proposed due to high risk of blackouts for major faults. Two separate HVDC schemes provide better stability. EAPP market needs further study to establish if Inga-Tanzania interconnetion would be viable.
Lesotho	275 MW; 0/100 Reserve margin: 11%	275 MW; 0/100 Reserve margin: 11%	• Lesotho's least cost generation options are to be a net importer for the planning horizon. An additional 132 kV link to RSA is required by 2022.
Malawi	4,203 MW; 59/41 Reserve margin: 0%	3,882 MW; 54/46 Reserve margin: -8%	• Without interconnections it is necessary to upgrade and expand the exisitng 132 kV and 400 kV system. • Least cost plan is to connect to Mozambique – more viable than some internal generation projects. Additional interconnections that may include Zambia and Tanzania should be subject of further studies. These could also be used to export surplus hydropower during high inflow seasons.
Mozambique	5,910 MW; 39/61 Reserve margin: 122%	6,060 MW; 65/35 Reserve margin: 126%	• Key transmission developments needed are connections to Malawi and building the STE grid from Tete area to Maputo to evacuate power from Mphanda Nkuwa identified as part of the least cost regional plan. Reinforcing 400 kV links to RSA and Zimbabwe may become viable later on.
Namibia	1,225 MW; 63/37 Reserve margin: 10%	1,000 MW; 57/43 Reserve margin: -4%	• Additional interconnectors required as system relies on imports in early years. Connection to Angola already highlighted but studies needed with better hydro plant data to decide if one or two lines are needed. • Recommended regional plan includes Kudu and Baynes projects by mid to late 2020's which requires second 400 kV line to RSA. Strengthening link to Zambia including the HVDC to Caprivi may also be beneficial.

South Africa	20,133 MW; 84/16 Reserve margin: 14%	11,958 MW; 82/18 Reserve margin: 0%	• RSA is net exporter until the mid to late 2020's, supported by the Nzhelele-Triangle line added early on. • In the least cost regional plan additional cross border reinforcements are need from 2030 onwards when RSA becomes a net importer. Trade with SAPP is through Namibia in the west, Botswana and Zimbabwe in the north and Mozambique and eSwatini in the east in addition to an HVDC from DRC.
eSwatini	132 MW; 0/100 Reserve margin: -54%	432 MW; 61/39 Reserve margin: 18%	• Least-cost plan has eSwatini as a net importer except for the last 2 years of the study horizon.
Tanzania	15,010 MW; 66/34 Reserve margin: 7%	14,602 MW; 71/29 Reserve margin: 4%	• Tanzania is assumed interconnected to SAPP through Zambia but the level of trade on this is limited to 200 MW by market uncertainties and voltage constraints in the Zambia-Tanzania border areas • Further studies needed to establish if higher trasnfer capacity can be justified for transfer of surplus hydro power during high inflow seasons.
Zambia	4,007 MW; 13/87 Reserve margin: -13%	5,269 MW; 26/74 Reserve margin: 3%	• Suggestion for EAPP-SAPP link to be back-to-back AC-DC-AC to deal with the relatively weak link between Zambia and Tanzania where it is difficult to economically justify the proposed 2000 MW link • Regional interconnection projects of major impact to Zambia are linked to the integration of Inga to Zambia and SA. Interconnections to Malawi and Mozambique are more of local rather than regional benefit
Zimbabwe	4,680 MW; 54/46 Reserve margin: 19%	3,770 MW; 45/55 Reserve margin: 2%	• Main impact of regional developments is the reinforcement of the Zimbabwe grid to allow more north-south power flows linked to developments in Inga and in Tete area of Mozambique. • Further studies needed on viability of alternative routes for reinforcement of Mozambique-Zimbabwe-South Africa interconnections, taking account of the timing of the STE grid
TOTAL SAPP (RM relative to coincident peak)	88,391 MW; 70/30 Reserve margin: 37%	74,615 MW; 60/40 Reserve margin: 24%	• Interconnections of non-operating members – Angola (to DRC and Namibia), Malawi (to Mozambique) and Tanzania (to Zambia) – recommended within the next 4–5 years