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Modeling Electricity Trade in Southern Africa

USER MANUAL FOR THE LONG-TERM MODEL

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User Manual

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The appendices are available on the SAPP web page at http://www.purdue.edu/IIES/SAPP. Contact clallen@ecn.purdue.edu for the username and password for gaining access to the files.

ACKNOWLEDGEMENTS

Edition 2

There are many colleagues who need to be recognized for the excellent contributions that they have made in making it possible for this user manual to be completed, both in Southern Africa and at Purdue. It has been a privilege and exciting to have worked with each one and to have learnt so much from one other. We hope that this manual will be helpful to all those who are modeling electricity policy issues and will learn from the example, documented here, of the Southern African Power Pool.

Colleagues and research students associated with Purdue University's State Utility Forecasting Group (SUFG) and School of Industrial Engineering have contributed significantly with the modeling analysis, coding, data collection and many communications between our two continents. At Purdue we need to name several people in particular: these are Zuwei Yu, Doug Gotham, Forrest Holland, Tom Morin, Gachiiri Nderitu, James Wang, Kevin Stamber, Frank Smardo, Farquad Alkhal, Basak Uluca, Pedro Gonzalez-Orbegoso and Dan Schunk. Many other research students have made such excellent contributions towards the model and coding that is described in this manual. Many thanks to you all.

Southern African colleagues have made this USAID funded project, "Modeling Electricity in Southern Africa", the success that it has been. This has been achieved through participation in the two modeling workshops, in August 1997 at Purdue, and in Cape Town in July 1998, as well as via numerous and frequent email communications with data transfer, modeling suggestions and requirements. We'd like to name some of the most frequent contributors. We give our thanks to them and the many others who have taken a part in developing this manual: Arnot Hepburn, Jean Louise Pabot, Roland Lwiindi, Alex Chileka, David Madzikanda, Alision Chikova, Edward Tsikirayi, Ferdi Kruger, Bruce Moore, Modiri Badirwang, Mario Houane, Bongani Mashwama, Senghi Kitoko, Eduardo Nelumba, John Kabadi, and Peter Robinson.

Back to our own office, here at Purdue, we owe many thanks to administrative assistants Barbara Gotham and Chandra Allen for all the many pages of typing and help with the organization that is involved in preparation of such a manual.

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Edition 3

Several minor improvements have been made since January. The most significant modeling improvement is with the trade variables. Funding for this collaborative modeling work is provided by USAID under its Equity and Growth through Economic

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<u>Edition 4</u>

Edition 4 of this manual for the SAPP has been updated for work done on the modeling between the Dar-Es-Salaam SAPP Management Meeting (August 1999) and the Johannesburg meeting (February 2000). This work has been in relation to the Dar-Es-Salaam specified Functional Requirements and the further development of the windows interface (Chapter 7). Changes made include data updates, revised terminology, and rewriting to reflect the new treatment of yearly hydro capacity and unmet reserve requirements.

Graduate and undergraduate students participating in this work for the final stage of Year 3 electricity capacity expansion planning in SAPP include: Frank Smardo, Basak Uluca, Iris Prasetyo, Nurhadi Siswanto, Jie Chi, Kevin Shidler, and John Leuders. Thank you to each of them and to Chandra Allen for the typing, editing, and compilation of the complete manual.

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<u>Edition 5</u>

Edition 5 of this manual for the SAPP has been updated for work done on the modeling between the Johannesburg meeting (February 2000) and the SAPP Windows Workshop (July 2000). In particular the insightful and enticed contribution from Dr. Jean-Louis Pabot of Eskom, have helped regarding analysis of trade flows and reserve quantities. His astute insights have prompted important clarifications to the definitions, notation, formulation and appendices to this fifth edition.

Graduate and undergraduate students participating in this work for the final stage of Year 3 electricity capacity expansion planning in SAPP include: Frank Smardo, Basak Uluca, Jie Chi, Kevin Shidler, and John Leuders. Thank you to each of them and to Chandra Allen for the typing, editing, and compilation of the complete manual.

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SAPP LT-Model Notation (June 2000)
(Equation Names Excluded)

P = User specified value.
V = Model specified variable.

Name	Definition
A	
AF(z,ty)	Autonomy factor for country *z* in period *ty* (fraction). (P)
AftCC(ty,z,ni)	Combined cycle plant cannot be built before or at year *ty*. (P)
AftCC(z,ni)	Combined cycle not built before or at period *ty*. (P)
AftHn(ty,z,nh)	New hydro plant cannot be built before or at year *ty*. (P)
AftHn(z,nh)	New hydro not built before or at period *ty*. (P)
AftLC(ty,z,ni)	Large coal plant cannot be built before or at year *ty*. (P)
AftLC(z,ni)	Large coal must not be built before or at period *ty*. 0 if unconstrained. (P)
Aftlines(ty,z,zp)	New line cannot be built before or at year *ty*. (P)
Aftlines(z,zp)	Line not built before or at period *ty*. (P)
AftSC(ty,z,ni)	Small coal plant cannot be built before or at year *ty*. (P)
AftSC(z,ni)	Small coal not built before or at period *ty*. (P)
AftT(ty,z,ni)	Turbine plant cannot be built before or at year *ty*. (P)
AftT(z,ni)	Turbine not built before or at period *ty*. (P)
AtCC(ty,z,ni)	Combined cycle plant must be built at period *ty*. (P)
AtCC(z,ni)	Combined cycle built at period *ty*. (P)
AtHn(ty,z,nh)	New hydro plant must be built at period *ty*. (P)
AtHn(z,nh)	New hydro built at period *ty*. (P)
AtLC(ty,z,ni)	Large coal plant must be built at period *ty*. (P)
AtLC(z,ni)	Large coal must be built at period *ty*. 0 if unconstrained. (P)
Atlines(ty,z,zp)	New line must be built at period *ty*. (P)
Atlines(z,zp)	Line built at period *ty*. (P)
AtSC(ty,z,ni)	Small coal plant must be built at period *ty*. (P)
AtSC(z,ni)	Small coal built at period *ty*. (P)
AtT(ty,z,ni)	Turbine plant must be built at period *ty*. (P)
AtT(z,ni)	Turbine built at period *ty*. (P)
B	
Base(ts,td,th,z)	Base year demand in season *ts*, day *td*, hour *th*, in country *z*. (MW) (P)
BefCC(ty,z,ni)	Combined cycle plant must be built before or at period *ty*. (P)
BefCC(z,ni)	Combined cycle built before or at period *ty*. (P)
BefHn(ty,z,nh)	New hydro plant must be built before or at period *ty*. (P)
BefHn(z,nh)	New hydro built before or at period *ty*. (P)
BefLC(ty,z,ni)	Large coal plant must be built before or at period *ty*. (P)
BefLC(z,ni)	Large coal must be built before or at period *ty*. 0 if unconstrained. (P)
Beflines(ty,z,zp)	New line must be built before or at period *ty*. (P)
Beflines(z,zp)	Line built before or at period *ty*. (P)
BefSC(ty,z,ni)	Small coal plant must be built before or at period *ty*. (P)
BefSC(z,ni)	Small coal built before or at period *ty*. (P)
BefT(ty,z,ni)	Turbine plant must be built before or at period *ty*. (P)
BefT(z,ni)	Turbine built before or at period *ty*. (P)
C	
crf(z,zp)	Capital recovery factor for transmission lines (fraction per year). (P)
crfi(z,i)	Capital recovery factor for existing thermal plants (fraction per year). (P)
crfih(z,ih)	An existing hydro plant's capital recovery factor (fraction per year). (P)

crfnh(z,nh)	Capital recovery factor for a new hydro plants (fraction per year). (P)
crfni(z,ni)	Capital recovery factor for new thermal plants (fraction per year). (P)
crfphn(z,phn)	Capital recovery factor for new pumped storage hydro plants (fraction per year). (P)

D

DecayHN	Decay rate of new hydro plants (fraction per year). (P)
DecayHO	Decay rate of existing hydro plants (fraction per year). (P)
DecayNCC	Decay rate of new combined cycle plants (fraction per year). (P)
DecayNLC	Decay rate of new large coal plants (fraction per year). (P)
DecayNSC	Decay rate of new small coal plants (fraction per year). (P)
DecayNT	Decay rate of new gas turbine plants (fraction per year). (P)
DecayPFN	Decay rate of new lines (fraction per year). (P)
DecayPFO	Decay rate of existing lines (fraction per year). (P)
DecayPGO	Decay rate of existing thermal plants (fraction per year). (P)
DecayPHN	Decay rate of new pumped hydro (fraction per year). (P)
DecayPHO	Decay rate of existing pumped hydro (fraction per year). (P)
dgr(z,ty)	Demand growth for a specific country in a specific period *ty* (fraction per period). (P)
dgrowth1(z)	Demand growth rate for period 1 (fraction per year). (P)
dgrowth2(z)	Demand growth rate for period 2 (fraction per year). (P)
dgrowth3(z)	Demand growth rate for period 3 (fraction per year). (P)
dgrowth4(z)	Demand growth rate for period 4 (fraction per year). (P)
dgrowth5(z)	Demand growth rate for period 5 (fraction per year). (P)
dgrowth6(z)	Demand growth rate for period 6 (fraction per year). (P)
dgrowth7(z)	Demand growth rate for period 7 (fraction per year). (P)
dgrowth8(z)	Demand growth rate for period 8 (fraction per year). (P)
dgrowth9(z)	Demand growth rate for period 9 (fraction per year). (P)
dgrowth10(z)	Demand growth rate for period 10 (fraction per year). (P)
disc	Discount rate (fraction per year). (P)
DLC(z)	Domestic loss coefficient for each region (1 plus fraction). (P)
DumpCost	Cost per MW of dumped energy. (P)
DumpEn(ty,ts,td,th,z)	Dumped Energy. (P)
DW	Equal to *n*. (P)
Dyr(ty,ts,td,th,z)	Demand in year *ty*, *ts*, *td*, *th*, in country *z*, equal to base year demand times growth rate. (P)

E

Enaf(z,ty)	Energy autonomy factor for country *z* in *ty*. (P)
EXPG(z,zp)	Governs how the gains from trade are to be divided between exporter and importer. Value set at .5 indicates gains split equally between the two. (Influences only country out report, Section F)

F

fdrought(ty,z)	Reduced water flow during drought. 1 = Normal and <1 is dry (fraction). (P)
Fdecom(z,i)	The period in which decommissioning is forced for old thermal plants. (P)
FdecomH(z,ih)	The period in which decommissioning is forced for old hydro plants. (P)
FGCC(z,ni)	Fixed cost for new combined cycle plants ($). (P)
FGLC(z,ni)	Fixed cost for new large coal plants ($). (P)
FixOMCC(z,ni)	Fixed *O&M* cost for combined cycle plants ($/MW/yr). (P)
FixOMLC(z,ni)	Fixed *O&M* cost for large coal plants ($/MW/yr). (P)
fixOMnh(z,nh)	Fixed *O&M* cost for new hydro ($/MW/yr). (P)
fixOMph(z,phn)	Fixed *O&M* cost for pumped storage ($/MW/yr). (P)
FixOMSC(z,ni)	Fixed *O&M* cost for small coal plants ($/MW/yr). (P)
FixOMT(z,ni)	Fixed *O&M* cost for gas turbine plants ($/MW/yr). (P)
Fmax(ty,zp,z)	Reserves held by country *zp* for country *z* during period *ty* (MW). (P)
Fmax(ty,z,zp)	Reserves held by country *z* for country *zp* during period *ty* (MW). (P)
FORICN(z,zp)	Forced outage rate for new transmission lines (fraction). (P)
FORICO(z,zp)	Forced outage rate for existing transmission lines (fraction). (P)
FORNCC(z,ni)	Forced outage rate for new combined cycle plants (fraction). (P)

FORnh(z,nh)	Forced outage rate for new hydro plants (fraction). (P)
FORNLC(z,ni)	Forced outage rate for new large coal plants (fraction). (P)
FORNSC(z,ni)	Forced outage rate for new small coal plants (fraction). (P)
FORNT(z,ni)	Forced outage rate for new gas turbine plants (fraction). (P)
FORoh(z,ih)	Forced outage rate for existing hydro plants (fraction). (P)
FORPGO(z,i)	Forced outage rate for existing thermal units (fraction). (P)
fpescNCC(z)	Escalation rate of fuel cost for new combined cycle plants (fraction per year). (P)
fpescNLC(z)	Escalation rate of fuel cost of new large coal plants (fraction per year). (P)
fpescNSC(z)	Escalation rate of fuel cost for new small coal plants (fraction per year). (P)
fpescNT(z)	Escalation rate of fuel cost for new gas turbines plants (fraction per year). (P)
fpescO(z, i)	Escalation rate of fuel cost of existing thermal plants (fraction per year). (P)
fpNCC(z, ni)	Fuel cost of new combined cycle plants ($/million BTU). (P)
fpNLC(z,ni)	Fuel cost of new large coal plants ($/million BTU). (P)
fpNSC(z,ni)	Fuel cost of small coal plants ($/million BTU). (P)
fpNT(z,ni)	Fuel cost of new gas turbine plants ($/million BTU). (P)
fpO(z,i)	Fuel cost of existing thermal plants ($/MWh). (P)

H

H(ty,ts,td,th,z,ih)	Generating level of existing hydro plants (MW)[variable]. (V)
HA(ty)	*n* times period *ty* (HA = *n)*. (P)
HDPSNmwh(z,phn)	New pumped storage hydro reservoir volume capacity (MWh per day). (P)
HDPSOmwh(z)	Existing pumped storage hydro reservoir volume capacity (MWh per day). (P)
HNcapcost(ty)	Construction cost of a new hydro plant ($). (P)
Hnew(ty,ts,td,th,z,nh)	Output for new hydro plants (MW) [variable]. (V)
HNexpstep(z,nh)	Expansion step for new hydro stations (MW). (P)
HNFcost(z,nh)	Fixed capital cost of new hydro stations ($). (P)
HNinit(z,nh)	Initial capacity of new hydro stations (MW). (P)
HNLF(z,nh)	Annual generation limit for new reservoir (GWh/year). (P)
HNVcost(z,nh)	Capital cost of additional capacity to new hydro stations ($/MW). (P)
HNVexp(ty,z,nh)	Number of units of the given expansion step size installed in *ty* for new hydro plants [integer or continuous variable]. (V)
HNVexp(tye,z,nh)	Number of units of the given expansion step size installed in *tye* for new hydro plants [integer or continuous variable]. (V)
HNVmax(z,nh)	Maximum MW expansion added to a new hydro station (MW). (P)
HOcapcost(ty)	Expansion cost for existing hydro plants ($) [variable]. (V)
HOexpstep(z,ih)	Expansion step for existing hydro (MW). (P)
HOinit(z,ih)	Initial capacity of an existing hydro station (MW). (P)
HOinitty(z,ih,ty)	Initial capacity of an existing hydro station in *ty* (MW). (P)
HOLF(z,ih)	Annual generation limit for existing reservoir (MWh/year). (P)
HOVcost(z,ih)	Capital cost of additional capacity for existing hydro stations ($/MW). (P)
HOVexp(ty,z,ih)	Number of units of the given expansion step size installed in *ty* for existing thermal plants [integer or continuous variable]. (V)
HOVexp(tye,z,ih)	Number of units of the given expansion step size installed in *tye* for existing thermal plants [integer or continuous variable]. (V)
HOVmax(z,ih)	Maximum MW expansions that can be added to an existing hydro station (MW). (P)
HOVmaxTY(z,ih,ty)	Maximum MW expansions that can be added to an existing hydro station in *ty* (MW). (P)
HRNCC(z,ni)	Heat rate of a new combined cycle plant (million BTU/MWh). (P)
HRNLC(z,ni)	Heat rate of a new large coal plant (million BTU/MWh). (P)
HRNSC(z,ni)	Heat rate of new small coal plants (million BTU/MWh). (P)
HRNT(z,ni)	Heat rate of a new gas turbine plant (million BTU/MWh). (P)
HRO(z,i)	Heat rate of existing thermal plants (million BTU/MWh); set equal to 1, since fuel cost for old plants is expressed in ($/KWh). (P)

I

i	Indice for an existing thermal plant. (P)
ih	Indice for an existing hydro plant. (P)

J

j	Indice for pumped hydro station. (P)

L

LM(z,th)	Load management capacity for each country each hour (MW). (P)

M

maxfor(z,zp)	Maximum for old or new line outage rates between *z* and *zp*. (P)
maxfor(zp,z)	Maximum for old or new line outage rates between *z* and *zp*. (P)
maxloss(z,zp)	Maximum of old or new line loss between *z* and *zp*. (P)
maxloss(zp,z)	Maximum of old or new line loss between *zp* and *z*. (P)
maxPFN(z,zp)	Maximum flow on a new line. (P)
maxPFO(z,zp)	Maximum flow on an old line. (P)
Mday(td)	Number of days in a year by day type. (P)
minCC(z,ni)	Minimum usage for combined cycle. (P)
minH(z,ih)	Minimum usage for old hydro. (P)
minHN(z,nh)	Minimum usage for new hydro. (P)
minLC(z,ni)	Minimum usage for large coal. (P)
minPFN(z,zp)	Minimum flow on a new line. (P)
minPFO(z,zp)	Minimum flow on an old line. (P)
minSC(z,ni)	Minimum usage for small coal. (P)
MinT(z,ni)	Minimum usage for gas turbine. (P)
Mperiod(ty)	Multiplier of years per period; equal to *n*. (P)
Mseason(ts)	Multiplier of seasons; number of months per season, as a fraction of 12 months. (P)
Mtod(th)	Number of hours/day represented by each day type. (P)

N

n	Number of years in each time period. (P)
NCCexpcost(z,ni)	Expansion cost of new combined cycle plants ($/MW). (P)
NCCexpstep(z,ni)	Expansion step size (increments) for new combined cycle plants (MW). (P)
nh	Indice for a new hydro plant. (P)
ni	Indice for a new thermal plant. (P)
NLCexpcost(z,ni)	Expansion cost of new large coal plants ($/MW). (P)
NLCexpstep(z,ni)	Expansion step size (increments) for new large coal plants (MW). (P)
NSCexpcost(z,ni)	Expansion cost of new small coal plants ($/MW). (P)
NSCexpstep(z,ni)	Expansion step size for new small coal plants (MW). (P)
NTexpcost(z,ni)	Expansion costs of new gas turbine plants ($/MW). (P)
NTexpstep(z,ni)	Expansion step size for new gas turbine plants (MW). (P)

O

Oexpcost(z,i)	Expansion cost of an existing thermal plant ($/MW). (P)
OMCC(z,ni)	Variable operating and maintenance cost of a new combined cycle plant ($/MWh). (P)
OMLC(z,ni)	Variable operating and maintenance cost of a new large coal plant ($/MWh). (P)
OMO(z,i)	Variable operating and maintenance cost of an existing thermal plant ($/MWh). (P)
OMSC(z,ni)	Variable operating and maintenance cost of a new small coal plant ($/MWh). (P)
OMT(z,ni)	Variable operating and maintenance cost of a new gas turbine plant ($/MWh). (P)
ord(ty)	Returns period ordinal number of what is in the parenthesis (period *ty*). (P)
ord(tya)	Returns period ordinal number of what is in the parenthesis (period *tya*). (P)
ord(tyb)	Returns period ordinal number of what is in the parenthesis (period *tyb*). (P)
ord(tye)	Returns period ordinal number of what is in the parenthesis (period *tye*). (P)
ord(z)	Returns period ordinal number of what is in the parenthesis (country *z*). (P)

P

PeakD(z)	Peak demand for each region in the base year (MW). (P)
PF(ty,ts,td,th,z,zp)	Power flow from country *z* to *zp* (MW) [variable]. (V)
PF(ty,ts,td,th,zp,z)	Power flow from country *zp* to *z* (MW) [variable]. (V)
PFNcapcost(ty)	Cost of new transmission capacity added in *ty* ($) [variable]. (V)
PFnew(ty,ts,td,th,z,zp)	Power flow over new lines (MW) [variable]. (V)

PFnew(ty,ts,td,th,zp,z)	Power flow over new lines (MW) [variable]. (V)
PFNFc(z,zp)	Fixed cost of new tie line (million $). (P)
PFNFcost(z,zp)	Fixed cost of new tie line ($). (P)
PFNinit(z,zp)	Initial capacity of new tie lines from country *z* to *zp* (MW). (P)
PFNinit(zp,z)	Initial capacity of new tie lines from country *zp* to *z* (MW). (P)
PFNloss(z,zp)	Transmission loss factor for new lines from country *z* to *zp* (fraction). (P)
PFNloss(zp,z)	Transmission loss factor for new lines from country *zp* to *z* (fraction). (P)
PFNVc(z,zp)	Cost of additional capacity on new lines (million $/MW). (P)
PFNVcost(z,zp)	Cost of additional capacity on new lines ($/MW). (P)
PFNVexp(ty,z,zp)	Capacity of new interconnectors added from country *z* to *zp* in *ty* (MW) [variable]. (V)
PFNVexp(ty,zp,z)	Capacity of new interconnectors added from country *zp* to *z* in *ty* (MW) [variable]. (V)
PFNVexp(tye,z,zp)	Capacity of new interconnectors added in *tye* (MW) [variable]. (V)
PFNVmax(z,zp)	Maximum MW expansions that can be added to a new tie line (MW). (P)
PFOcapcost(ty)	Cost of expanding existing transmission line capacity in *ty* ($). (P)
PFOinit(z,zp)	Initial existing tie line capacities (MW). (P)
PFOloss(z,zp)	International transmission loss coefficient for existing lines from country *z* to *zp* (fraction). (P)
PFOloss(zp,z)	International transmission loss coefficient for existing lines from country *zp* to *z* (fraction). (P)
PFOVc(z,zp)	Cost of expanding existing lines (millions $/MW). (P)
PFOVcost(z,zp)	Cost of expanding existing lines ($/MW). (P)
PFOVexp(ty,z,zp)	Capacity expansion of an existing transmission line from country *z* to *zp* in *ty* (MW) [variable]. (V)
PFOVexp(tye,z,zp)	Capacity expansion of an existing transmission line from country *zp* to *z* in *tye* (MW) [variable]. (V)
PFOVmax(z,zp)	Maximum MW additions that can be put on existing lines (MW). (P)
PG(ty,ts,td,th,z,i)	Power level of all existing plants (MW) [variable]. (V)
PGmin(z,i)	Minimum usage for old thermal plants. (P)
PGNcapcost(ty)	Expansion cost of all new thermal plants in *ty* ($) [variable]. (V)
PGNCC(ty,ts,td,th,z,ni)	Power level for new combined cycle plant (MW) [variable]. (V)
PGNCCexp(tyb,z,ni)	Number of units of the given expansion step size installed in *tyb* for new combined cycle plants [integer or continuous variable]. (V)
PGNCCinit(z,ni)	Initial capacity of a new combined cycle plant (MW). (P)
PGNCCmax(z,ni)	Maximum MW that can be added to a new combined cycle plant (MW). (P)
PGNLC(ty,ts,td,th,z,ni)	Power level of a new large coal plant (MW) [variable]. (V)
PGNLCexp(tyb,z,ni)	Number of units of the given expansion step size installed in *tyb* for new large coal plants [integer or continuous variable]. (V)
PGNLCinit(z,ni)	Initial capacity of a new large coal plant (MW). (P)
PGNLCmax(z,ni)	Maximum MW that can be added to a new large coal plant (MW). (P)
PGNSC(ty,ts,td,th,z,ni)	Power level of a new small coal plant (MW) [variable]. (V)
PGNSCexp(ty,z,ni)	Number of units of the given expansion step size installed in *ty* for new small coal plants [integer or continuous variable]. (V)
PGNSCexp(tyb,z,ni)	Number of units of the given expansion step size installed in *tyb* for new small coal plants [integer or continuous variable]. (V)
PGNSCexp(tye,z,ni)	Number of units of the given expansion step size installed in *tye* for new small coal plants [integer or continuous variable]. (V)
PGNSCmax(z,ni)	Maximum MW that can be added to a new small coal plant (MW). (P)
PGNT(ty,ts,td,th,z,ni)	Power level of a new gas turbine plant (MW) [variable]. (V)
PGNTexp(ty,z,ni)	Number of units of the given expansion step size installed in *ty* for new gas turbine plants [integer or continuous variable]. (V)
PGNTexp(tyb,z,ni)	Number of units of the given expansion step size installed in *tyb* for new gas turbine plants [integer or continuous variable]. (V)
PGNTexp(tye,z,ni)	Number of units of the given expansion step size installed in *tye* for new gas turbine plants [integer or continuous variable]. (V)
PGNTmax(z,ni)	Maximum MW that can be added to a new turbine plant (MW). (P)
PGOcapcost(ty)	Expansion cost of all existing thermal plant ($) [variable]. (V)
PGOexp(tyb,z,i)	Expansion of existing thermal plants in *tyb* [variable]. (V)

PGOexpstep(z,i)	Expansion step size for existing thermal plant units (MW). (P)
PGOinit(z,i)	Current capacity for existing thermal plants (MW). (P)
PGOinitTY(z,i,ty)	Current capacity for existing thermal plants in *ty* (MW). (P)
PGOmax(z,i)	Maximum MW that can be added to an existing thermal plant (MW). (P)
PGPSN(ty,ts,td,th,z,phn)	Electricity production level of a new pumped storage plant (MW) [variable]. (V)
PGPSO(ty,ts,td,th,z)	Electricity production level of an existing pumped storage plant (MW) [variable]. (V)
PGPSOinit(z)	Existing pumped hydro capacity (MW). (P)
phn	Indice for proposed new pumped hydro. (P)
PHNcapcost(ty)	Cost of new pumped storage installed in *ty* ($)[variable]. (V)
PHNFcost(z,phn)	Pumped hydro fixed capital cost ($). (P)
PHNinit(z,phn)	Initial capacity of proposed new pumped hydros (MW). (P)
PSNloss(phn)	New pumped storage loss coefficient (fraction). (P)
PSOloss	Existing pumped storage loss coefficient (fraction). (P)
PUPSN(ty,ts,td,th,z,phn)	Electricity consumption level of a new pumped storage plant (MW) [variable]. (V)
PUPSO(ty,ts,td,th,z)	Electricity consumption level of an existing pumped storage plant (MW) [variable]. (V)

R

reshyd(z)	Reserve margin of hydro plants for each country (fraction). (P)
resthm(z)	Reserve margin of thermal plants for each country (fraction). (P)

T

td	Indice for time in days (offpeak, average, peak). (P)
th	Indice for the time in hours (*hr9, avnt, hr19, hr20, hr21, avdy*). (P)
ts	Indice for the time in seasons (summer, winter). (P)
ty	Indice for the period. (P)
tya	Alias of *ty*. (P)
tyb	Alias of *ty*. (P)
tye	Alias of *ty*. (P)

U

UE(ty,ts,td,th,z)	Unserved energy (MWh) [variable]. (V)
UEcost	Cost of unserved energy ($/MWh). (P)
UFORNCC(z,ni)	Unforced outage rate for new combined cycle plants (fraction). (P)
UFORNLC(z,ni)	Unforced outage rate for new large coal plants (fraction). (P)
UFORNSC(z,ni)	Unforced outage rate for new small coal plants (fraction). (P)
UFORNT(z,ni)	Unforced outage rate for new gas turbine plants (fraction). (P)
UFORPGO(z,i)	Unforced outage rate for existing thermal plants (fraction). (P)
UM(z,ty)	Unmet reserve requirement for country *z* in *ty* (MW) [variable]. (V)
UMcost	Cost of unmet reserve requirements ($/MW). (P)

V

VarOMoh(z,ih)	*O&M* variable cost for old hydro ($/MWh). (P)
VarOMnh(z,nh)	*O&M* variable cost for new hydro ($/MWh). (P)
VarOMph(z,phn)	*O&M* variable cost for pumped storage ($/MWh). (P)

W

wcost(z,ty)	Opportunity cost of water for country *z* in *ty* ($/MWh). (P)

Y

YCC(ty,z,ni)	Decision to build/not build initial step of new combined cycle plants in *ty* [binary variable]. (V)
YCC(tya,z,ni)	Decision to build/not build initial step of new combined cycle plants in *tya* [binary variable]. (V)
YCC(tye,z,ni)	Decision to build/not build initial step of new combined cycle plants in *tye* [binary variable]. (V)
Yh(ty,z,nh)	Decision to build/not build initial step of new hydro plants in *ty* [binary variable]. (V)
Yh(tye,z,nh)	Decision to build/not build initial step of new hydro plants in *tye* [binary variable]. (V)
YLC(ty,z,ni)	Decision to build/not build initial step of new large coal plants in *ty* [binary variable]. (V)
YLC(tya,z,ni)	Decision to build/not build initial step of new large coal plants in *tya* [binary variable]. (V)

YLC(tye,z,ni)	Decision to build/not build initial step of new large coal plants in *tye* [binary variable]. (V)
Yper(ty)	*Yper* = 1 if period is to be counted, otherwise *Yper* = 0. (P)
Ypf(ty,z,zp)	Decision to build/not build initial step of new interconnector in *ty* [binary variable]. (V)
Ypf(ty,zp,z)	Decision to build/not build initial step of new interconnector in *ty* [binary variable]. (V)
Ypf(tye,z,zp)	Decision to build/not build initial step of new interconnector in *tye* [binary variable]. (V)
Yph(ty,z,phn)	Decision to build/not build initial step of pumped storage hydro in *ty* [binary variable]. (V)
Yph(tye,z,phn)	Decision to build/not build initial step of pumped storage hydro in *tye* [binary variable]. (V)

Z

z	Indice for source country. (P)
zp	Indice for destination country. (P)

SAPP LT-Model Equation Names (June 2000)

Name	**Definition**
A	
AftCCFix(ty,z,ni)	Combined cycle plant cannot be built before or at year *ty*.
AftLCFix(ty,z,ni)	Large coal plant cannot be built before or at year *ty*.
AftNhFix(ty,z,nh)	New hydro plant cannot be built before or at year *ty*.
AftpfFix(ty,z,zp)	New line cannot be built before or at year *ty*.
AftSCFix(ty,z,ni)	Small coal plant cannot be built before or at year *ty*.
AftTFix(ty,z,ni)	Turbine plant cannot be built before or at year *ty*.
AtCCFix(ty,z,ni)	Combined cycle plant must be built at period *ty*.
AtLCFix(ty,z,ni)	Large coal plant must be built at period *ty*.
AtNhFix(ty,z,nh)	New hydro plant must be built at period *ty*.
AtpfFix(ty,z,zp)	New line must be built at period *ty*.
AtSCFix(ty,z,ni)	Small coal plant must be built at period *ty*.
AtTFix(ty,z,ni)	Turbine plant must be built at period *ty*.
B	
BefCCFix(ty,z,ni)	Combined cycle plant must be built before or at period *ty*.
BefLCFix(ty,z,ni)	Large coal plant must be built before or at period *ty*.
BefNhFix(ty,z,nh)	New hydro plant must be built before or at period *ty*.
BefpfFix(ty,z,zp)	New line must be built before or at period *ty*.
BefSCFix(ty,z,ni)	Small coal plant must be built before or at period *ty*.
BefTFix(ty,z,ni)	Turbine plant must be built before or at period *ty*.
C	
CapcostH(ty)	New hydro capital cost.
CapcostHO(ty)	Old hydro capital cost.
CapcostPF(ty)	New tie lines capital cost.
CapcostPFO(ty)	Old tie lines PW capital cost.
CapcostPH(ty)	New pumped hydro capital cost.
CCmin(ty,z,ni)	New combined cycle minimum generation level.
CCsum(z,ni)	Only one combined cycle plant at a site.
CON1a(ty,ts,th,z,ni)	New gas turbine generation limit of off-peak day for both seasons.
CON1b(ty,th,z,ni)	New gas turbine generation limit of peak day, summer.
CON1c(ty,th,z,ni)	New gas turbine generation limit of peak day, winter.
CON1d(ty,ts,th,z,ni)	New gas turbine generation limit of average day for both seasons.
CON2a(ty,ts,th,z,ni)	New combined cycle generation limit of off-peak day.
CON2b(ty,th,z,ni)	New combined cycle generation limit of peak day, summer.
CON2c(ty,th,z,ni)	New combined cycle generation limit of peak day, winter.
CON2d(ty,ts,th,z,ni)	New combined cycle generation limit of average day.
CON3a(ty,ts,th,z,ni)	New small coal generation limit of off-peak day.
CON3b(ty,th,z,ni)	New small coal generation of peak day, summer.
CON3c(ty,th,z,ni)	New small coal generation of peak day, winter.
CON3d(ty,ts,th,z,ni)	New small coal generation of average day.
CON4a(ty,ts,th,z,ni)	New large coal generation of off-peak day.
CON4b(ty,th,z,ni)	New large coal generation of peak day, summer.
CON4c(ty,th,z,ni)	New large coal generation of peak day, winter.
CON4d(ty,ts,th,z,ni)	New large coal generation of average day.
CON5(ty,z,ni)	Expansion can be put only after construction for new combine cycle plants.
CON6(ty,z,ni)	Expansion can be put only after construction for new large coal plants.
CON7(z,ni)	Expansion limit for gas turbine.
CON8(z,ni)	Expansion limit for small coal.
CON9a(ty,ts,th,z,i)	Old thermal plants generation limit of off-peak day.

CON9b(ty,th,z,i)	Old thermal plants generation limit of peak day, summer.
CON9c(ty,th,z,i)	Old thermal plants generation limit of peak day, winter.
CON9d(ty,ts,th,z,i)	Old thermal plants generation limit of average day
CON10(z,i)	Old thermal plants expansion limit.
CON20(z,ni)	Only one large coal plant on a site.
CONCOST1(ty)	Expansion costs of old thermo plants.
CONCOST2(ty)	Construction and expansion costs of new thermo plants.
D	
Demand(ty,ts,td,th,z)	The system load balance equation.
E	
EnergyAF(ty,ts,td,th,z)	The energy autonomy factor constraint for all but RSA and MOZ.
EnerAFa(ty,ts,td,th)	The energy autonomy factor constraint for all but NSA and SSA.
EnerAFb(ty,ts,td,th)	The energy autonomy factor constraint for all but NSA.
EnerAFc(ty,ts,td,th)	The energy autonomy factor constraint for all but SSA.
EnerAFd(ty,ts,td,th)	The energy autonomy factor constraint for all but NMOZ and SMOZ.
EnerAFe(ty,ts,td,th)	The energy autonomy factor constraint for all but NMOZ.
EnerAFf(ty,ts,td,th)	The energy autonomy factor constraint for all but SMOZ.
F	
Fmaxtcapaj(z)	Requirement that aggregate transmission capacity take into account generation reserves held for and by others.
H	
hcon1(ty,z,nh)	The requirement that Batoka S. be built before Batoka N.
HN_one(z,nh)	Only one dam per site.
HNmin(ty,z,nh)	New hydro minimum generation level.
HNmust(ty,z,nh)	Enforce fixed cost in new hydro.
HNmw(ty,ts,td,th,z,nh)	New hydro MW capacity.
HOlimit(z,ih)	Old hydro maximum additional capacity limit.
HOmin(ty,z,ih)	Old hydro minimum generation level.
HOmw(ty,ts,td,th,z,ih)	Old hydro MW capacity limit.
L	
LCmin(ty,z,ni)	New large coal minimum generation level.
LCsum(z,ni)	Only one large coal plant per site.
M	
MWhNDam(ty,z,nh)	Annual MWh capacity limit for new dams
MWhODam(ty,z,ih)	Annual MWh capacity limit for existing dams
N	
Newpumped(ty,ts,td,z,phn)	Loss adjusted KWh generation must be less than KWh pumped for new pumped storage.
O	
objf	The objective function to be minimized.
Oldpumped(ty,ts,td,z)	Loss adjusted KWh generation must be less than KWh pumped for old pumped storage.
P	
PF_one(z,zp)	Only one pumped hydro unit per site.
PFmax(ty,z,zp)	Insures power flow is less than maximum value on old lines.
PFmin(ty,z,zp)	Insures power flow is greater than minimum value on old lines.
PFNdirect(ty,zp,z)	Enforce expansion in *zp, z* direction.
PFNmax(ty,z,zp)	Insures power flow is less than maximum value on new lines.
PFNmin(ty,z,zp)	Insures power flow is greater than minimum value on new lines.
PFNmust(ty,z,zp)	Incur fixed cost before doing any expansion.
PFNmw(ty,ts,td,th,z,zp)	New interconnectors MW capacity limit.
PFOdirect(ty,zp,z)	Enforce expansion in other direction.
PFOlimit(z,zp)	Old interconnectors maximum additional capacity limit.
PFOmw(ty,ts,td,th,z,zp)	Old interconnectors MW capacity limit.

PgminE(ty,z,i)	Old thermal minimum generation level.
PHN_one(z,phn)	Only one pumped hydro per site.
PHNcap(ty,ts,td,z,phn)	New pumped storage hydro reservoir volume (MWh) capacity constraint.
PHNmw(ty,ts,td,th,z,phn)	New pumped hydros MW capacity.
PHOcap(ty,ts,td,z)	Existing pumped storage hydro reservoir volume (MWh) capacity constraint.
PHOmw(ty,ts,td,th,z)	Old pumped hydro MW capacity.
R	
ResvREG2(ty,z)	Reserve constraint for all regions.
ResvREG4(ty,z)	Autonomy factor constraint for all but RSA and MOZ.
ResvREG4a(ty)	Autonomy factor constraint for all but SSA and NSA.
ResvREG4b(ty)	Autonomy factor constraint for all but NSA.
ResvREG4c(ty)	Autonomy factor constraint for all but SSA.
ResvREG4d(ty)	Autonomy factor constraint for all but SMOZ and NMOZ.
ResvREG4e(ty,'NMz')	Autonomy factor constraint for all but NMOZ.
ResvREG4f(ty,'SMz')	Autonomy factor constraint for all but SMOZ.
S	
SCmin(ty,z,ni)	New small coal minimum generation level.
T	
Tmin(ty,z,ni)	New turbine minimum generation level.
Y	
Ypfdirect(ty,zp,z)	Enforce construction in *zp, z* direction.

CHAPTER 1

INTRODUCTION TO THE SAPP LONG-TERM MODEL

The first edition of this manual was written in response to requests from delegates at the July 1998 modeling workshop in Cape Town, South Africa. The 12 countries in SAPP are shown in Figure 1.1.

This fourth edition incorporates the many changes in the model and the data that support it, which have taken place since the last edition was completed in August 1999. Further editions will be forthcoming as the model is changed in response to user requests.

This manual has two objectives: (a) a full description of all the equations in the model, and the logic behind each, for the more technically oriented model users, who may wish to understand the detailed workings of the model, and, if necessary, alter the source code (Chapters 2 though 5); (b) a full description of how to use the model utilizing the Windows interface for those less interested in model detail, and more interested in how model results change with changes in the economic and technical assumptions (Chapters 6 and 7).

The model is the result of more than two years of joint research between the member utilities of SAPP and Purdue researchers. The utilities that have taken part in this modeling work include:

BPC	Botswana Power Corporation
EDM	Electricidade de Mocambique
ENE	Empresa Nacional de Electricidade (Angola)
Escom	Electricity Supply Commission of Malawi
Eskom	South Africa parastatal power utility (not an acronym)
LEC	Lesotho Electricity Corporation
NamPower	Namibia parastatal power utility
SEB	Swaziland Electricity Board
SNEL	Societe Nationale d’Electricite (DRC)
Tanesco	Tanzania Electric Supply Company

Zesa	Zimbabwe Electricity Supply Authority
Zesco	Zambia Electricity Supply Corporation

The LT model is designed as a mixed integer mathematical program (MIP). It can be run in a MIP mode or a linear programming mode (LP). The model, which uses GAMS and CPLEX software, minimizes the total costs (capital, fuel, operational and maintenance, and unserved energy) of the operation and capacity expansion of SAPP's generation and transmission system over a planning horizon, which can be specified by the user; typical planning horizons are 10 to 20 years, but longer or shorter periods can be specified.

The LT model has several sets of decision variables, each aimed at the answers to the usual questions utility planners confront when designing interconnected utility systems;

- In the short run:
  (a) Should a utility operate its own units to meet demand, or is it cheaper to import power from other utilities? If a utility operates its own units, how should they be dispatched against varying hourly demand?
  (b) Should a utility maintain its own reserve Megawatt capacity, or is it cheaper to meet its reserve requirements by purchasing capacity from neighboring utilities?
  (c) How shall the limited daily MWh capacity of pump storage and hydro units be allocated over the daily, weekly, and seasonal demand cycle?
  (d) What provision if any, should be made for utility self-sufficiency in the meeting of demands? In the provision of reserve capacity for reliability purposes?
- In the long run:
  (a) Should a utility construct its own units to meet growing demand, or share in the construction costs of other utility construction projects?
  (b) What transmission projects should be funded to allow access to other utility projects?

(c) What mix of new generation units – thermal, hydro, pump storage – should be chosen?

(d) What is the impact on SAPP cost of forcing a project into the solution in a given year? Of requiring that it enter the solution at or before a given year? Of preventing it from entering before a given year?

(e) To what extent should self-sufficiency be a factor in the choice of constructing one's own units versus sharing in the cost of construction of other utility units?

More generally, how should the gains from trade be shared among those utilities who decide to buy either capacity or energy? What is the impact of various wheeling arrangements on the make or buy decision?

To answer these and other questions the model chooses the optimal values of 600 integer variables and 500,000 continuous variables, subject to 20,000 constraints.

The objective of the LT model is to minimize the present value of operating costs, unserved energy and unserved reserves, plus the costs of generation and transmission capacity expansion in the SADC region over a user specified time horizon:

(a) If SAPP were to choose the operation/expansion plan which minimizes total SAPP costs.

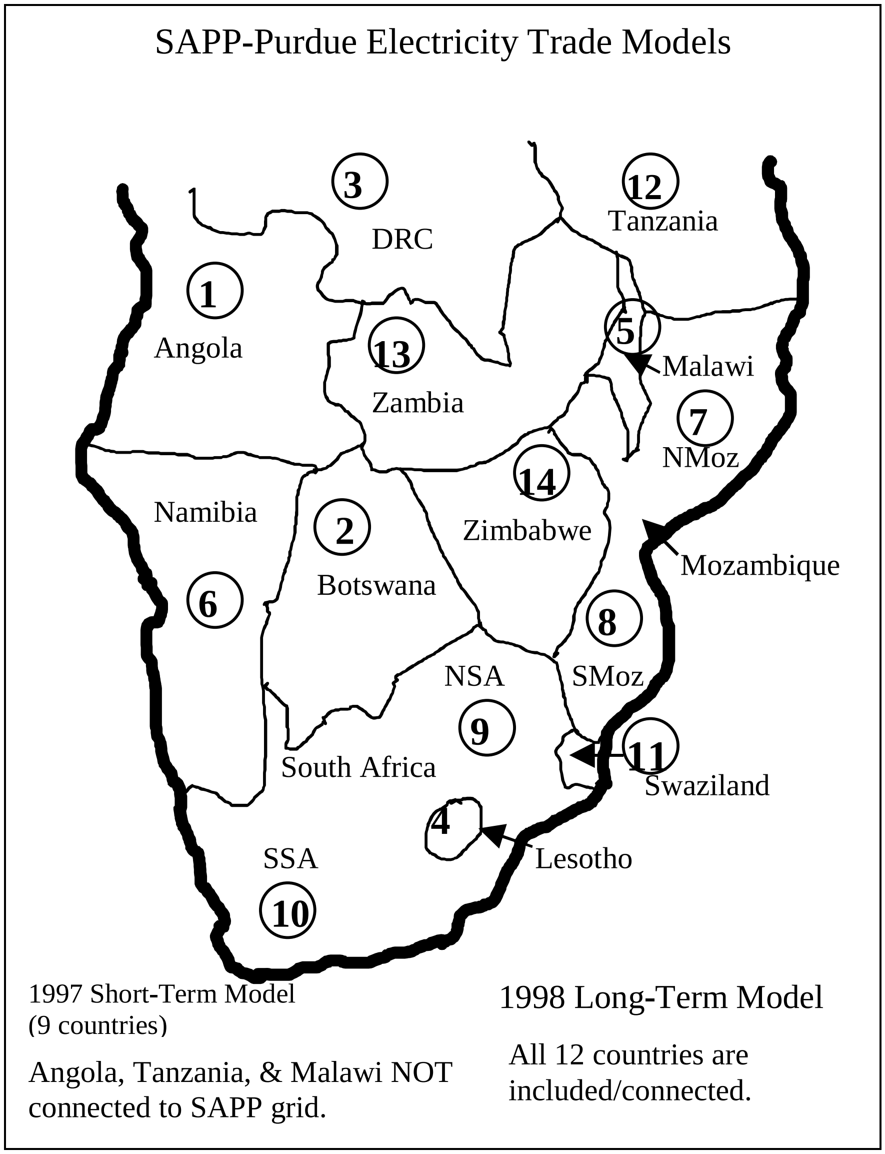
(b) If each country optimizes separately, subject to a user specified maximum fraction of domestic peak demand to be met by imported reserves.

Within the model three separate electricity commodities can be traded to reduce SAPP wide costs;

- Spot electricity-e.g., electricity purchased on the spot market on an hourly "if available" basis;
- Firm electricity-e.g., electricity purchased on condition that seller countries agree to hold in reserve enough capacity to insure that energy in an amount up to the agreed quantity is there if needed by the purchaser countries;

- Capacity "rights"-e.g. the agreed upon capacity itself, to be held in reserve by seller nations to back up firm power sales.

Figure 1.1 SAPP-Purdue Electricity Trade Models



Many user options are allowed in the model; they are of two types:

(a) Model structure options, which allow the user to easily alter the fundamental structure of the model without changing the source code;

(b) Model data options, which allow the user to specify the economic and technical characteristics of the various demand and supply options which are available.

Examples of the model structure options include:

- Choice of the number of periods and years per period in the planning horizon, as well as the base year of the horizon;
- Choice of the solution method – mixed integer, or continuous variables;
- Specification of the units that must be built, cannot be built before, during, or after a specified year in the horizon;
- Choice of minimum/maximum usage constraints on old or new projects, including forced decommissioning of units.

(New nodes cannot be added to the current model without users modifying the source code.)

Examples of data options include

- Modifying the cost and technical data, which represent current or planned SAPP projects.
- Adding new projects not now specified by SAPP.

A high-speed high efficiency personal computer has been assembled as requested by SAPP to specifically run the LT model.

The specification of this personal computer for providing the best performance is described below:

PentiumII BX 100 MHz motherboard,

PentiumII 500 MHz processor,

512 Mb 100 MHz RAM,

9 Gb UW SCSI hard drive.

The LT model is based on the modeling work that was done with the SAPP, in 1997/98, with the short-term (ST) model. The generating stations that exist, in the year 2000, in the LT model are shown below in Tables 1.1 and 1.2.

Table 1.1 SAPP Thermal Generation Data for Existing Plants in 2000

Country & Station Name	PGmax (MW)	Country & Station Name	PGmax (MW)
Angola		Tanzania	
Luanda	136	Ubungo	112
Botswana		Tegeta	100
Moropule (1-4)	132	Swaziland	
Lesotho		Edwaleni	9
Old Thermal 1	1.8	RSA	
Mozambique		Arnot (NSA)	1980
Beira (NMoz)	12	Duvha (NSA)	3450
Maputo (SMoz)	62	Hendrina (NSA)	1900
Namibia		Kendal (NSA)	3840
Vaneck	114	Kriel (NSA)	2850
Paratus	24	Lethabo (NSA)	3558
Zimbabwe		Majuba (NSA)	1836
Hwange 1-6	847	Matimba (NSA)	3690
Munyati	37	Matla (NSA)	3450
Harare	74	Tutuka (NSA)	3510
Bulawayo	83	Koeberg (Nuclear) (SSA)	1840
		Zambia	
		Unnamed	108

Table 1.2 SAPP Hydropower Generation Data for Existing Plants in 2000

Country & Station Name	Hmax (MW)	Country & Station Name	Hmax (MW)
Angola		Malawi	
Cambambe 1	180	Nkula A&B	124
Matela	51	Tedzani 1, 2, 3	92
Mabubas 1 & 2	18	Kapichiri A (Phase I & II)	128
Lomaum 1,2,4	35	RSA	
Biopio	14	Gariep (SSA)	252
Capanda II	182	Vanderkloof (SSA)	220
DRC		Palmiet & Drakensburg (SSA)	1400
Inga 1,2	887	Tanzania	
Nseki	126	Hale	19
Nzilo	54	Kidatu	187
Mwadingusha	34.2	Mtera	78
Koni	14	Pangani	66
Zongo	30	N-Mungu	7
Lesotho		Kihansi	177
Muela	72	Zimbabwe	
Mozambique		Kariba South (Ext)	750
Hydro Cahora Bassa N. (NMoz)	2075	Zambia	
Chicamba (NMoz)	38.4	Kariba North	600
Mavuzi (NMoz)	52	Kafue	900
Corumana (SMoz)	16.6	Victoria Falls	100
Namibia		Swaziland	
Ruacana	249	Old Hydro I	39

The new stations that can be built in the SAPP model are a combination of SAPP specified projects as well as more generic types, which are based on costs of current USA data. The SAPP specified projects are listed in Table 1.3. The project identifier, in the right hand column, is the code name of the project in the model coding. Note that a project is identified in the coding by three parameters: country, technology and identifier.

All of the demand data in the model is based on the electricity demand forecast for the year 2000. This data is illustrated below in Table 1.4. This data was supplied by the SAPP Generation & Planning Working Group (GWPG) in July 1999. The full set of demand data is in Appendix I.

The weighting of the demand constraint will vary with season (*Mseason*), day type (*Mday*, *offpeak*, *average* and *peak*) and time of day (*Mtod*). Each of these three types of weighting is broken up as shown below:

Mseason			To be found in Section 1 in Appendix VII.
	Summer	0.75	
	Winter	0.25	
Mday			To be found in Section 1 in Appendix VII.
	Offpeak	52	
	Average	260	
	Peak	52	
Mtod			To be found in the beginning of Appendix I.
	hr9	1	
	Avnt	8	
	hr19	1	
	hr20	1	
	hr21	1	
	avdy	12	

The electricity demand in subsequent growth periods, after the base year 2000, is determined by using demand growth rates which multiply the values of demand in the base year 2000. Following the February 1999 SAPP meeting in Swaziland the Eskom IEP6 growth rates, shown in Table 1.5, were used (low growth). These values were further superceded by values supplied by the SAPP Feb2000 data sheets and are illustrated in Table 1.6. The complete set of demand growth rates for each expansion period is in Appendix II, data.inc code file (Sections 2, 3, 4).

Table 1.3 Optional New SAPP Generating Capacity (Febb2000 data sheets)

Country	Powerstation **Optional Projects**	# of Units	Unit Size (MW)	Total Capacity (MW)	Type T/H/PS**	Project Identifier
Angola	Cambambe II 1, 2, 3, 4	4	91	364	H – N	NewH1
Angola	TG 12.5	2	12.5	25	T – GT	NewGT1
Angola	TG 30	2	30	60	T – GT	NewGT2
Botswana	Moropule (5,6)	2	115	230	T – SC	NewSC1
DRC	Grand Inga ST1, 2, 3, 4	26	750	24750	H – N	NewH1
DRC	Inga 3	19	192	3648	H – N	NewH2
Malawi	Lower Fufu	2	90	180	H – N	NewH1
Malawi	Mpatamanga	1	315	315	H – N	NewH2
Malawi	Kholombidzo	4	170	680	H – N	NewH3
Mozambique	Mepanda Uncua (NMoz)	6	340	2040	H – N	NewH1
Mozambique	Malema River (NMoz)	1	80	80	H – N	NewH2
Mozambique	Elefantes River (NMoz)	1	60	60	H – N	NewH3
Mozambique	Lurio River (NMoz)	1	200	200	H – N	NewH4
Mozambique	Boroma (NMoz)	4	110	440	H – N	NewH5
Mozambique	Lupata (NMoz)	6	108	648	H – N	NewH6
Mozambique	Mavuzi (NMoz)	1	60	60	H – N	NewH7
Mozambique	GT Beira (NMoz)	6	100	600	T – GT	NewGT1
Mozambique	Moatize (NMoz)	1	600	600	T – SC	NewSC1
Mozambique	Buzi/Pande (NMoz) (Natural Gas)	1	600	600	T – CC	NewCC1
Namibia	Kudu (Natural Gas)	1	750	750	T – CC	NewCC1
Namibia	Epupa	3	120	360	H – N	NewH1
South Africa	Lekwe * (NSA)	6	659	3954	T – LC	NewLC1
South Africa	Gas Turbine (NSA)	4	250	1000	T – GT	NewGT1
South Africa	Komati A (Recomm.) (NSA)	9	100	900	T – SC	NewSC1
South Africa	Grootvlei (Recomm.) (NSA)	6	190	1140	T – SC	NewSC2
South Africa	Komati B (Recomm.) (NSA)	4	110	440	T – SC	NewSC3
South Africa	Camden (Recomm.) (NSA)	8	190	1520	T – SC	NewSC4
South Africa	PB Reactor (SSA)	1	1000	1000	T – NUC	NewLC1
South Africa	Pumped Storage A (SSA)	1	999	999	PS – N	NewPS1
South Africa	Pumped Storage B (SSA)	1	999	999	PS – N	NewPS2
South Africa	Pumped Storage C (SSA)	1	999	999	PS – N	NewPS3
South Africa	High Head UGPS (SSA)	1	1000	1000	PS – N	NewPS4
South Africa	Pebble Bed Reactor (SSA)	1	1000	1000	T – LC	NewLC1
Tanzania	Ruhudji	4	89.5	358	H – N	NewH1
Tanzania	CT Ubungo	1	40	40	T – GT	NewGT1
Zambia	Kafue River - ITT	2	40	80	H – N	NewH1
Zambia	Kafue Lower	4	150	600	H – N	NewH2
Zambia	Batoka North	4	200	800	H – N	NewH3
Zambia	Kariba North	2	150	300	H – N	NewH4
Zambia	Lusaka	1	100	100	T – SC	NewSC1
Zambia	Maamba	1	160	160	T – SC	NewSC2
Zimbabwe	Hwange 7 & 8	2	300	600	T – SC	NewSC1
Zimbabwe	Gokwe North	4	321	1284	T – SC	NewSC2
Zimbabwe	Batoka South	4	200	800	H – N	NewH1

*Can be replicated **Note: SC – Small Coal; LC – Large Coal; GT – Gas Turbine; CC – Combined Cycle T – Thermal; H – Hydropower; PS – Pumped Storage; NUC – Nuclear; ext – expansion of existing site; recomm – recommissioned existing plant

Table 1.4 Parameter *PeakD(z)*; Table *(ts,td,th,z)* Hourly System Load

	Ang	Bot	Les	Mwi	NMz	SMz	Nam
summer.peak.avnt	337	195	95	101	82	71	173
summer.peak.hr9	455	258	134	177	97	127	281
summer.peak.avdy	434	230	120	149	67	127	209
summer.peak.hr19	531	237	147	183	99	160	259
summer.peak.hr20	507	241	133	163	105	150	291
summer.peak.hr21	460	238	124	137	119	117	291

Source: SAPP – GWPG (May 2000)
Full set of demand data is in Appendix I.

Table 1.5 Maximum Demand Growth Rates (MW)

COUNTRY	LOW % p.a.	MEDIUM % p.a.	HIGH % p.a.
Angola	6.8	9.1	13.0
Botswana	3.8	5.1	5.7
Lesotho	2.0	5.2	9.3
Malawi	0.8	3.3	6.2
Mozambique	10.6	13.6	17.0
Namibia	6.4	8.3	10.0
South Africa	2.4*	4.2	6.5
Swaziland	1.7	3.4	5.2
Tanzania	3.8	6.6	9.8
Zambia	2.5	5.1	8.1
Zimbabwe	2.3	4.6	7.3

Source: 1999 Eskom IEP6
*Eskom e-mail, June 23,

Table 1.6 Parameter *dgrowth2(z)*

Ang	1.099
Bot	1.041
Les	1.020
Mwi	1.049
NMz	1.054
SMz	1.054
Nam	1.113
NSA	1.024
SSA	1.024
Swz	1.046
Taz	1.084
DRC	1.050
Zam	1.056
Zim	1.041

Full set of demand growth data is in Appendix II.

The LT model includes the expected eleven interconnected countries of SAPP in the year 2000 (Figure 1.2). The LT model interconnects two countries, Malawi and Tanzania, to the SAPP grid, which had not been in the grid of the 1997 ST model. An option to finally connect Angola (Figure 1.3) is in the LT model.

All the international lines that are committed for the year 2000 and the long-term transmission line options are shown in Figures 1.2 and 1.3. Existing international line transfer capabilities at the year 2000 are also listed in Table 1.7. The totally new international line options for are listed in Table 1.8 for the horizon 2000 to 2020. With an average demand growth rate of 4% for the region and over a 20-year period it would mean that electricity supplies would have to more than double. Increased trade will not be possible unless major expansions in these international lines take place.

It is hoped that this user manual will not only inform new users of the LT model on how to execute the model, change the values of parameters and understand the outputs but also to obtain a thorough understanding of the model itself. The transparency of this SAPP LT model is one of its greatest strengths when used in the context of discussion among different utilities and parties engaged in electricity trading and project evaluation. All of the main input and output files are illustrated in Figure 1.4 and a short summary of each file is given.

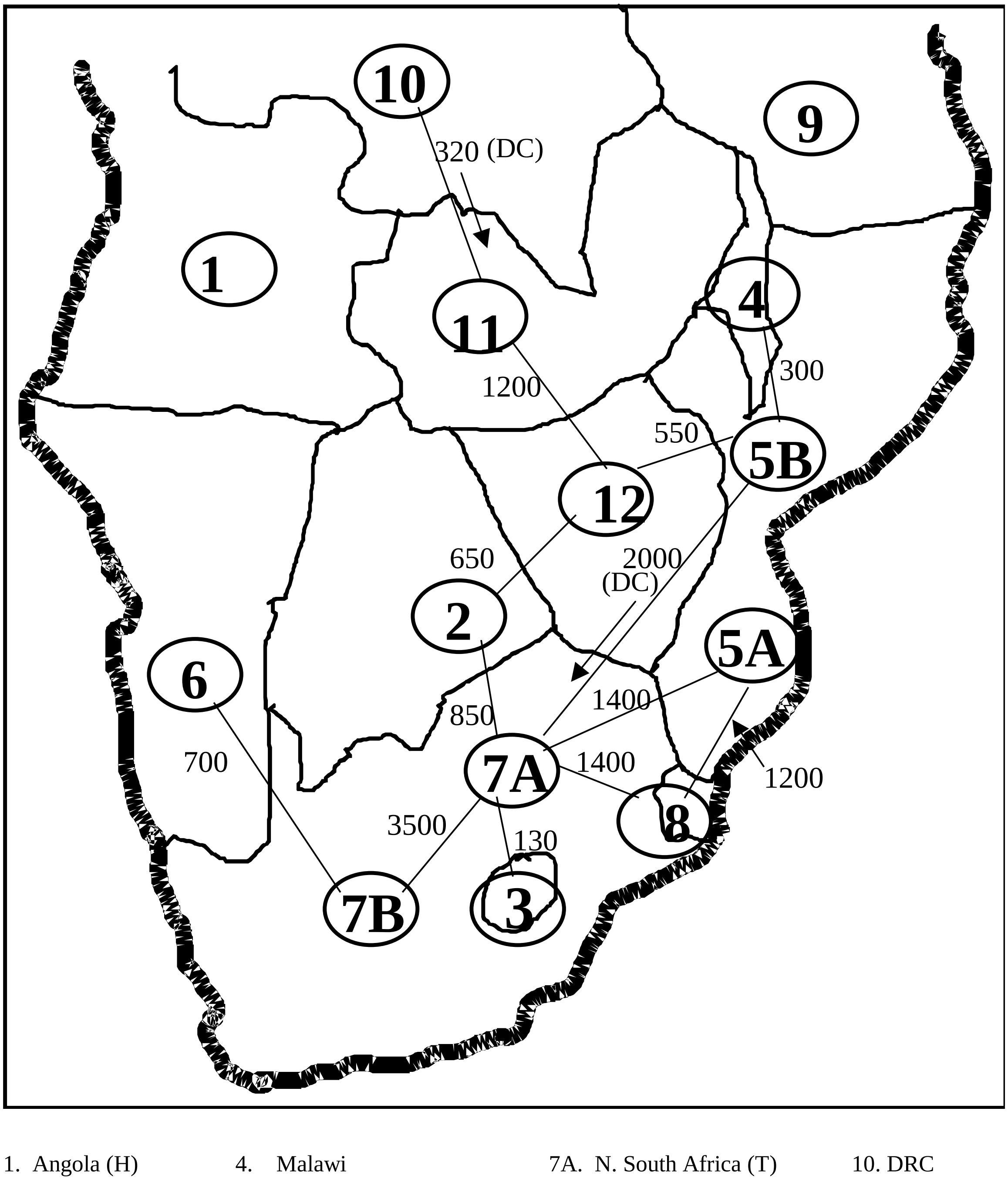
The 1997 ST model demonstrated the potential for additional trade and the gains that could be made if the system chooses the least cost mix of generation and imports/exports, rather than the fixed contract trades now in place between SAPP members. The short-run model had minimized existing thermal and hydro generator dispatch costs (fuel, variable *O&M*) plus fixed unit commitment (start-up and shut-down) costs over the short term, subject to:

(a) Hourly demand constraints known with certainty -- as described -- which require domestic and export demands in all regions plus within-region fixed distribution losses to be met by imports (less transmission loss assumed quadratic in flow) plus domestic production in that day;

(b) Derated generation and transmission transfer capability capacity constraints;

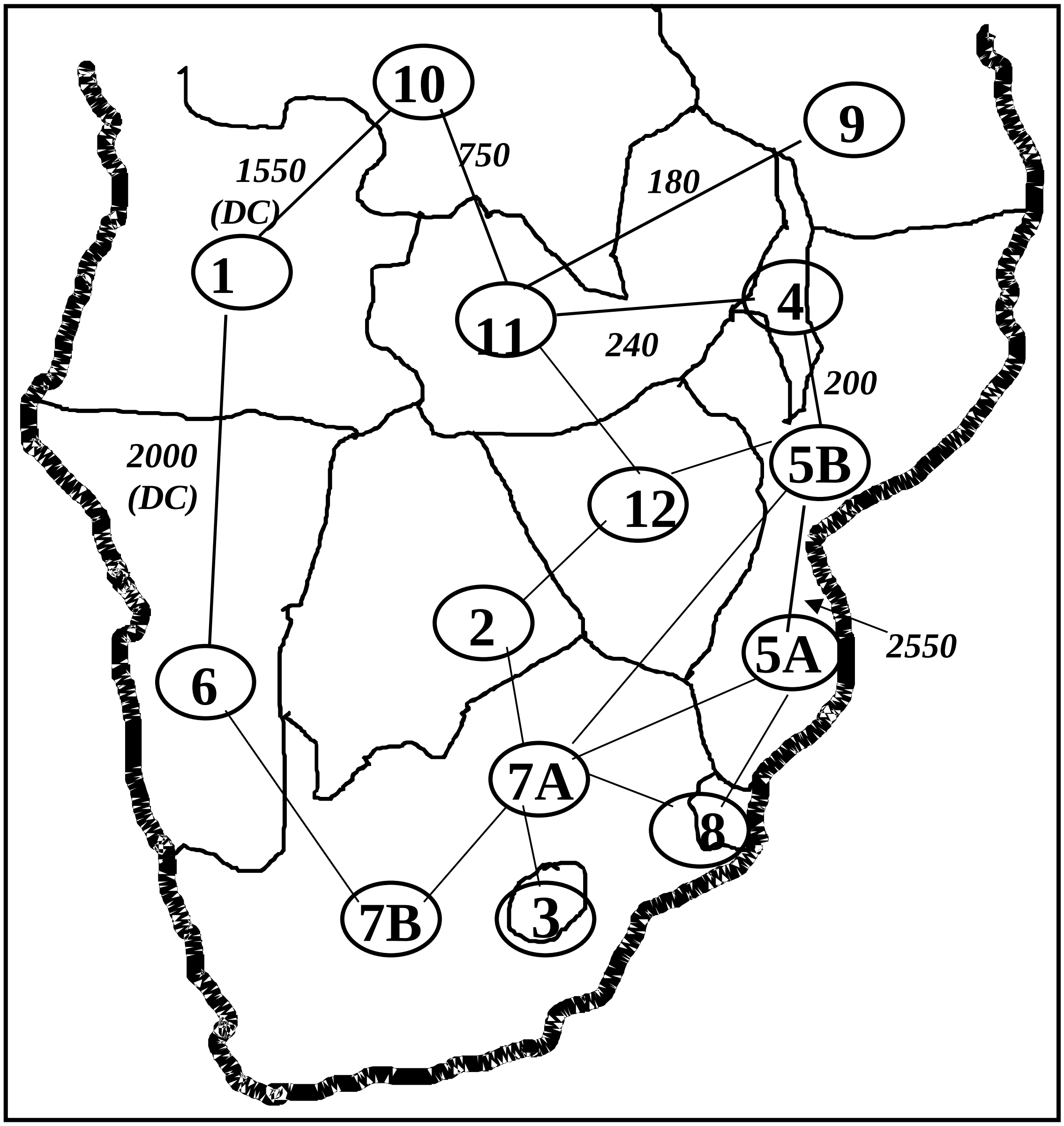
(c) Constraints on minimum up and down time and “must run” conditions for generators;
(d) System spinning reserve requirements;
(e) Constraints requiring hourly hydro MW generation to be constrained by installed MW capacity, and constraints which limit seasonal hydro MWh generation to the seasonal water available in the reservoir.
(f) Constraints capturing the operation of pumped hydro storage.
(g) An assumed cost of unserved energy.

Figure 1.2 SAPP International Maximum Practical Transfer Capacities Existing or Committed for the Year 2000 (MW) (Appendix III, Section 1)



1. Angola (H)	4. Malawi	7A. N. South Africa (T)	10. DRC
2. Botswana (T)	5A. S. Mozambique (H)	7B. S. South Africa	11. Zambia (H)
3. Lesotho	5B. N. Mozambique	8. Swaziland	12. Zimbabwe (H, T)
(H) = hydro site	6. Namibia (H, T)	9. Tanzania (H, T)	*(T) = thermal site*

Figure 1.3 SAPP International Transfer Proposed Initial Capacity Options for after 2000 (MW) (Appendix III, Section 7)



1. Angola (H)	4. Malawi	7A. N. South Africa (T)	10. DRC
2. Botswana (T)	5A. S. Mozambique (H)	7B. S. South Africa	11. Zambia (H)
3. Lesotho	5B. N. Mozambique	8. Swaziland	12. Zimbabwe (H, T)
(H) = hydro site	6. Namibia (H, T)	9. Tanzania (H, T)	*(T) = thermal site*

(DC) = direct current line
(Note: all lines, once built, are allowed to expand their capacity)

Table 1.7 SAPP International Maximum Practical Transfer Capacities Existing or Committed for the Year 2000

Line Name	Line Capacity (MW)	Loss Coefficient (%)	Max. Addition to Line (MW)	Forced Outage Rate (%)
Bot – NSA	850	1.70	3000	0.2
Bot – Zim	650	2.50	3000	1.2
Les – NSA	130	0.60	500	1.9
Mwi – NMz	300	2.40	0	0.4
NMz – Mwi	300	2.40	0	0.4
NMz – NSA	2000	99.9	18000	2.4
NMz – Zim	550	3.00	1000	0.9
SMz – NSA	1400	14.00	3000	0.8
SMz – Swz	1200	1.60	2000	0.4
Nam – SSA	700	5.00	18000	0.8
NSA – Bot	850	12.0	3000	0.2
NSA – Les	130	0.60	500	1.9
NSA – NMz	2000	99.90	18000	2.4
NSA – SMz	1400	14.00	3000	0.8
NSA – SSA	3500	4.00	11000	0.5
NSA – Swz	1400	1.60	2000	1.0
SSA – Nam	700	5.00	18000	0.8
SSA – NSA	3500	4.00	11000	0.5
Swz – SMz	1200	1.60	2000	0.4
Swz – NSA	1400	1.60	2000	1.0
DRC – Zam	320	5.60	18000	0.9
Zam – DRC	320	99.90	18000	0.9
Zam – Zim	1200	0.012	18000	0.2
Zim – Bot	650	2.50	3000	1.2
Zim – NMz	550	3.00	1000	0.9
Zim - Zam	1200	0.012	18000	0.2

Table 1.8 SAPP International Transfer Capacity Options for 2000 - 2020

Line Name	Line Capacity (MW)	Loss Coefficient (%)	Max. Addition to Line (MW)	Forced Outage Rate (%)
Ang – Nam	2000	14.0	18000	1.3
Ang – DRC	1550	4.8	18000	1.1
Mwi – NMz	200	2.4	700	0.4
Mwi – Zam	240	4.0	500	0.7
NMz – Mwi	200	2.4	700	0.4
NMz – SMz	2550	99.9	3000	2.4
SMz – NMz	2550	10.0	3000	2.4
Nam – Ang	2000	14.0	18000	1.3
Taz – Zam	180	8.0	5000	1.3
DRC – Ang	1550	4.8	18000	1.1
DRC – Zam	750	3.0	18000	1.0
Zam – Mwi	240	4.0	500	0.7
Zam – Taz	180	8.0	5000	1.3
Zam - DRC	750	99.9	18000	1.0

All lines data is fully listed in Appendix III lines.inc code file.

The near radial nature of the network shown in Figure 1.2 plus the fact that some lines from the hydro plants are DC lines suggests that the modelers can safely leave out the load flow constraints in the model, since the magnitude of unintended power flow is probably small. However, the same radial nature does increase system vulnerability to generation/transmission failure, requiring system reliability and stability to be carefully addressed in the model. (For further details see the notes of the August/September 1997 Purdue/SAPP workshop.)

While the results of relaxing the short-run model's capacity constraints indicated that only the relaxation of the transmission capacity constraint was cost effective, the question of the efficacy of capacity expansion of any sort can only be fully answered by a LT model of the type developed below which allows such expansion as part of the optimization.

The LT model, while starting with the same basic structure, drops and adds variables and constraints to create a model which addresses a different question: what are the benefits to SAPP members of harmonizing their capacity expansion plans over the long term rather than each member adding capacity individually?

The model allows each SAPP member to specify separately their own desired reliability levels for domestic power (by generation type), exports, and imports, as well as their own financial parameters for project selection. Additional joint planning benefits would take place if SAPP were to harmonize their reliability criterion and financial parameters, but this is not necessary for the model to run.

In order to estimate these benefits of SAPP coordinating the expansion of capacity to produce a SAPP-wide least-cost expansion plan, the model is run in two modes:

Mode 1: Self-sufficiency mode; each country's domestic generation capacity is maintained at a specified fraction (up to 100%) of yearly peak demand plus reserve requirement, thus insuring a sufficient supply of energy if import flows are disrupted.

Mode 2: Free-trade mode; the three commodities traded – spot energy, firm energy, and firm capacity are free to trade to their SAPP wide cost minimizing levels.

The LT model has now been constructed to reflect the following advantages of regional, rather than country-by-country, generation and transmission capacity planning:

- Lower Reserve Requirements: As individual generators represent a smaller fraction of the total system load, their unplanned outages are less likely to result in an overall generation shortage. Thus, more diverse generation sources result in lower reserve requirements. Joint planning for utilities will increase generation diversity, thereby resulting in lower reserve requirements than would occur under separate planning. While lower reserve requirements are a benefit of regional planning, this model does not implicitly capture that benefit. This benefit would have to be determined outside the model and then the appropriate reserve requirement could be placed in the model. The resulting SAPP wide-reserve margin, which would be lower than the individual utility reserve margins for the reasons stated in this paragraph, would then be used.
- Load Diversity: Not all utilities experience peak load conditions at the same time of day due to the different characteristics of the customers they serve. Similarly, they experience annual peak demand on different days. Therefore, the chronological sum of the individual utility loads provides a peak that is lower than the sum of the individual peak demands. Since generation capacity must be capable of handling the peak demand during the year, separate planning will result in larger generation requirements than will joint planning.
- Economies of Scale: Generally, it requires less capital to construct one large facility than is required to build an equivalent capacity with several smaller units. Similarly, multiple units at a single site are cheaper to build than the same units at numerous different sites. These economies of scale result from

common use of facilities, such as fuel handling, transformers, and transmission lines. Joint planning allows these economies to be captured more frequently than separate planning does by allowing utilities to share a jointly planned unit.

- More Available Options: Joint planning may allow a utility to utilize generation options for both energy and capacity requirements that are otherwise unavailable when planning is done separately. Thus a utility with little or no hydro sites available will not have to build a more expensive type of generation.

In addition to reflecting these advantages, the model must take account of the extraordinary uncertainty regarding demand growth in the SAPP region, as well as uncertainty on the supply side -- the impact of drought, and line or unit failure.

Long-run expansion decisions must consider alternative growth and supply scenarios. It is almost a certainty that an expansion plan based on most likely growth and supply scenarios will <u>not</u> be the preferred option, if its performance is measured against all scenarios. Flexible capacity expansion scenarios -- ones where the cost of over, or under estimating demand/supply are not catastrophic to the region -- are always preferred.

An added feature of the LT model is to allow each SAPP participant to decide on the maximum level of dependence on imports expressed as a domestic generation reserve margin -- domestic energy production capacity divided by peak demand. This number can be between 0 and 1, depending on each country's need for security and autonomy.

To keep the LT model computationally feasible for PC use (as specified by SAPP):

(a) Unit commitment costs are converted to average cost per kWh use;

(b) The quadratic generation cost, and transmission line losses were replaced by piece-wise linear relations;

(c) The minimum up and down time constraints for thermal generators are dropped, thus eliminating the need for a large number of integer variables and constraints; and

(d) Unit-by-unit reserve margins are replaced by regional reserve requirements.

(e) The 24 one-hour demand patterns for each SAPP member were reduced to 6-hour types.

(f) To save running time of the model it can be used in a relaxed mode by switching from MIP to LP.

Added to the model are constraints and variables, which capture:

- The present value of the new equipment and operating costs over the planning horizon.
- Demands for six days per year, with separate hourly patterns, representing peak, off-peak and average days for two seasons -- summer and winter.
- The expected growth of SAPP member demand for each period over a user specified planning horizon.
- The possibility of drought curtailing hydro power (except Inga).
- The transmission and generation (both hydro and thermal) capacity additions proposed by SAPP members, including their purchase and installation costs, operating cost, and proposed dates of completion.
- The possibility of additional transmission capacity in fixed increments of capacity.
- The three types of trade that can take place between regions;
    - (a) firm power trade, which requires that the exporting country hold the firm contract maximum amount of MW capacity in reserve to insure firm power trade availability when needed by the importing country;
    - (b) non-firm power trade between countries, that is, flows for which the export country is not required to keep reserve.
    - (c) firm capacity trade, which allows capacity short countries to satisfy reserve margin constraints by purchasing “capacity rights” from other countries;
- Two ways of modeling capacity expansion - as a continuous variable or as multiples of a fixed unit size.

- The capacity and economic characteristics of all, “off the shelf” options above can be set by the user, if so desired.
- The decommissioning/gradual derating of older, less efficient plants.
- User-specified levelized capital recovery factors reflecting both the cost of capital and equipment life to allow new equipment costs to enter into the objective function in the proper manner.
- The impact of forced outage rates on available capacity for all periods of operation, while limiting planned outages for maintenance to off-peak periods.
- The impact of demand-side management (*DSM*) on daily load profiles.
- Conditional construction options -- e.g., undertake Kariba S. only if Batoka completed.
- Agreed-upon SAPP reserve requirements for member thermal and hydro capacity.

Finally, the model inputs and outputs have been revised to make the model results easier to trace to changes in input assumptions, and to generally improve its usefulness to SAPP members.

The long-run SAPP model will choose, from the set of alternative capacity expansion options, least-cost solutions to the augmented SAPP network as listed in Table 1.3.

In order to more accurately capture the spatial location of both generation and consumption points in the model, as well as reflect the realities of the existing/proposed transmission system, the Republic of South Africa and Mozambique are represented by two demand nodes each rather than one.

For each of the time-weighted representative hours in a time-weighted given day type in a given year, the model dispatches the energy from plants on line in that year to meet hourly demand at least system cost -- e.g., imports/exports enter the solution if the system optimization finds it cheaper to trade than to produce domestically. Since start-up/shutdown (unit commitment) costs have been levelized and added to the constant variable cost/kWh of plant operation, and the line losses are assumed to be linear in flow, the hourly dispatch problem can be quickly solved by a linear programming code.

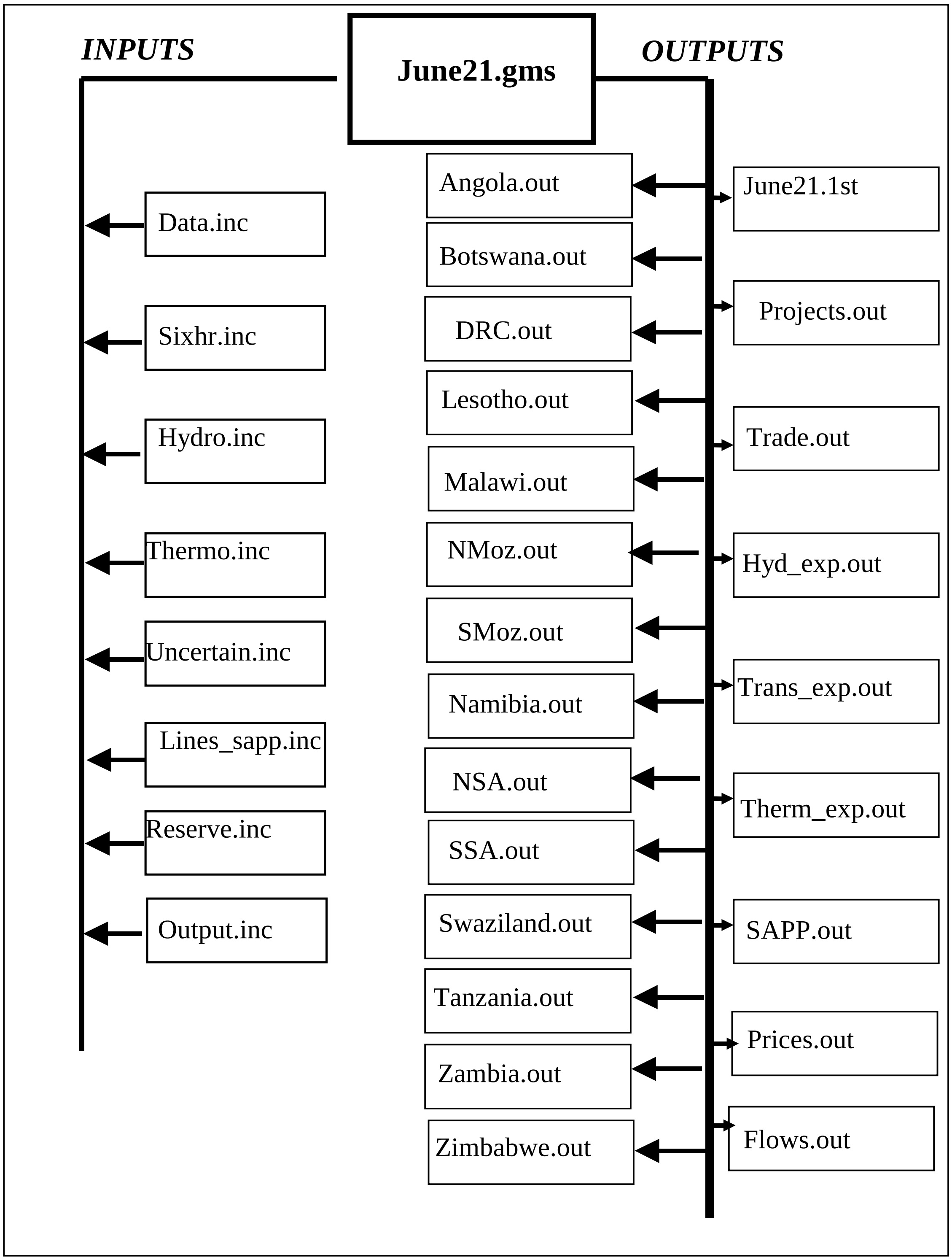
To determine the optimal expansion of the generation/transmission network in a given year, the model looks ahead to future years' growth demands, and calculates if it is cheaper (or even feasible) to continue to meet demand from existing units, or to add both transmission and generation capacity, and meet the demands from a combination of new and old plants and lines. A new unit or line is added only when the present value of existing unit or line operating cost savings allowed by construction of the new unit or line exceeds the present value of the levelized yearly capital cost plus operating cost of the new unit or line.

In addition to the new facility construction option, the model also allows, where possible, expansion of existing site generation capacity.

The mathematical description of the long-run model is broken into sections dealing with the modeling of demand, capacity utilization variables and costs, line losses, load balance equations, water use constraint, expansion of transmission and generation capacity, reserve margins, model summary, the treatment of uncertainty, and the benefits of collective planning.

The structure of the LT model consists of nine main input coded files and more than 20 output files. These files which constitute the LT model are shown in Figure 1.4. A brief summary of the contents of each file is also given.

Figure 1.4 The Files that Comprise the June 21 2000 Long-Term Model



Summary of the Files Used in the SAPP Long-Term Model

(1) June21.gms - Main program, contains all optimization constraints, optimizes model, no changes will be made to this file.

Data Files

(2) Thermop.inc – Contains data on the cost to expand new thermal stations, data on existing capacities, maximum expansion of existing capacities, and the capital recovery factor on the thermal stations.

(3) Lines_sapp.inc – Contains cost of expanding new lines and cost of new lines. Loss of energy due to resistance in old lines, loss of energy due to resistance in new lines, initial capacity of new lines, capital recovery of new lines, and cost of additional capacity on new lines.

(4) Hydro.inc – Contains data on the cost to expand new hydro stations, data on existing capacities, maximum expansion of existing capacities, and the capital recovery factor on the hydro stations.

(5) Sixhr.inc – Peak demand for each region: highest demand for one hour for current year.

(6) Uncertain.inc – Contains: data on uncertainties (i.e. expected rainfall).

(7) Reserve.inc – Contains: Autonomy factor – self reliance of each country, reserve margin for each country, forced outage rate for both transmission lines and for all plant types in country, unforced outage rate for all plant types in country, and largest generator station for each country.

(8) Data.inc – Contains data on the demand growth, and domestic growth, which can be changed by user.

(9) Output.inc – Generates the output files which contain the necessary data used for analysis.

Output Files

(10) June21.lst – Generic output file created by gams.

(11) Therm_exp.out – Thermal expansion plans from running the model.

(12) Hyd_exp.out – Hydropower expansion plans from running the model.

(13) Trade.out – Trade quantities from running the model.

(14) Trans_exp.out - Transmission expansion plans from running the model.

(15) Projects.out – All of the chosen projects are defined in this file.

(16) Country.out – The expansion results as they pertain for each country, and SAPP as a whole. (Angola.out, Botswana.out, etc.)

(17) SAPP.out – Regional output reports.

(18) Prices.out – Trade pricing analysis.

(19) Flows.out – Export/Import flows

The analysis of the model follows in Chapters 2, 3, 4, and 5. Chapter 6 is an introduction to the technical operation of the model and Chapter 7 is an introduction to the interface for general users of the manual.