Modeling Electricity Trade
in Southern Africa
USER MANUAL
FOR THE
LONG-TERM MODEL

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User Manual

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NOTATION

Notation is according to the file names: (1) hydro.inc, (2) thermop.inc, (3) lines.inc, (4) demand.inc, (5) reserve.inc, (6) sixhr.inc, (7) uncertain.inc, (8) Sapp.gms

(1) Hydro.inc

crfih(z,ih)	{Existing hydro capital recovery factor}
crfnh(z,nh)	{capital recovery factor for new hydro}
fdamN(z,nh,ts)	New Dams MWh capacity multiplier
fdamO(z,ih,ts)	Old Dams MWh capacity multiplier
HDNmwh(z,nh)	{annual MWh capacity of new Dam}
HDOmwh(z,ih)	{annual MWh capacity of Existing DAM type hydro}
HDOmwh(z,ih)	{annual MWh capacity of Existing DAM type hydro}
HNFcost(z,nh)	Fixed Capital Cost (US$)
HNinit(z,nh)	Initial MW capacity of New hydro Stations
HNVcost(z,nh)	{Capital cost of additional Capacity $/MW new hydros}
HNVmax(z,nh)	Max possible MW addition to a new hydro station
HOinit(z,ih)	{Existing hydro initial capacity (MW)}
HOVcost(z,ih)	{Capital cost of additional Capacity $/MW old hydros}
HOVmax(z,ih)	Max possible expansion on existing hydro
HRNmwh(ts,z,nh)	{Seasonal MWh capacity of new Run of River}
HRNmwh(ts,z,nh)	{Seasonal MWh capacity of new Run of River}
HROmwh(ts,z,ih)	{Seasonal MWh cap of existing Run of River}
HROmwh(ts,z,ih)	{Seasonal MWh cap of existing Run of River}
wcost;	{Opportunity cost of water $/MWh}

(2) Thermop.inc

crfi(z,i)	{capital recovery factor for old thermals}
crfni(z,ni)	{capital recovery factor for new thermal}
fpescNCC(z)	escalation rate of fuel cost of new combined cycle
fpescNT(z)	escalation rate of fuel cost of new gas turbine
fpescO(z,i)	escalation rate of fuel costs of old thermo plants
fpNCC(z,ni)	{fuel costs of new combined-cycle cent/10000/BTU}
fpNLC(z,ni)	{fuel costs of new large coal plants cent/1000/BTU}
fpNSC(z,ni)	{fuel costs of new small coal plants cent/10000/BTU}
fpNT(z,ni)	{fuel costs of new gas turbine cent/10000/BTU}
fpO(z,i)	fuel costs of old thermo plants dollar per MWh
NCCexpstep(z,ni)	{new combined cycle plants}
NLCexpstep(z,ni)	{new large coal plants}
PGOinit(z,i)	current capacity for old thermo plants
PGOmax(z,i)	max possible MW addition to old thermo plants
FGCC(z,ni)	{fixed costs for new combined-cycle plants}
FGLC(z,ni)	{fixed costs for new large coal plants}
FGSC(z,ni)	{fixed costs for new small coal plants}
FGT(z,ni)	{fixed costs for new gas turbine plants}
fpescNLC(z)	escalation rate of fuel cost of new large coal
fpescNSC(z)	escalation rate of fuel cost of new small coal
HRNCC(z,ni)	
HRNLC(z,ni)	
HRNSC(z,ni)	
HRNT(z,ni)	
HRO(z,i)	{heat rate of old thermo plants BTU/kWh}

NCCexpcost(z,ni)	{expansion costs dollar/MW of new combined cycle plants}
NLCexpcost(z,ni)	{expansion costs dollar/MW of} {new large coal plants}
Oexpcost(z,i)	expansion costs dollar per MW of old plants
PGNCCinit(z,ni)	{initial capacity of new combined-cycle plants}
PGNCCmax(z,ni)	
PGNLCinit(z,ni)	{initial capacity of new lagre coal plants}
PGNLCmax(z,ni)	
PGNSCinit(z,ni)	{initial capacity of new small coal plants}
PGNTinit(z,ni)	{initial capacity of new gas turbine plants}

(3) Lines.inc

PFNFc(z,zp)	New Tie lines Fixed cost mill US $
crf(z,zp)	{capital recovery factor for transmission lines}
PFfix(z,zp)	fixtrade between region z and zp (MWh per day)
PFNinit(z,zp)	New Tie lines capacities (MW)
PFNloss(z,zp)	{transmission loss factor [0-1]}
PFNVc(z,zp)	{Cost of additional capacity on new lines Mill $/MW}
PFNVmax(z,zp)	New Tie lines max possible MW addition
PFOinit(z,zp)	Tie line capacities (MW)
PFOloss(z,zp)	{International transmission loss coefficient}
PFOVc(z,zp)	{cost of expanding existing lines in mill $}
PFOVm(z,zp)	{max possible MW addition to existing lines}
PFNFcost(z,zp)	{convert from millions to dollars}
PFNVcost(z,zp)	{convert to dollars}
PFOVmax(z,zp)	{max possible MW addition to existing lines}

(4) demand.inc

PeakD(ty,z)	{peak demand for each region in each year}
july2497(th,z)	Hourly System load on July 24 1997
Mtod(th)	
thT	{number of representative hours modeled per day}

(5) reserve.inc

AF(z,ty)	{autonomy factor}
FORICN(z,zp)	{forced outage rate for new transmission line}
FORICO(z,zp)	{forced outage rate for old transmission line}
FORPGO(z,i)	{force outage rate for old thermo units}
LM(th,z)	{load management capacity for each region each hour}
LMsapp /0/	{load management capacity for SAPP}
maxG(z)	{max generation unit capacity of each region}
UFORHO /0.120/	{UFOR for old hydro plants}
UFORPGO(z,i)	{unforce outage rate for old thermo plants}
FORHN /0.028/	{FOR for new hydro plants}
FORHO /0.028/	{FOR for old hydro plants}
FORNCC(z,ni)	
FORNLC(z,ni)	
FORNSC(z,ni)	
FORNT(z,ni)	
FX(z)	{firm exports for each region}
LM(th,z)	{load management capacity for each region each hour}
LM(z)	
LM(z)	{load management capacity for each region}

maxGsapp /920/	{max generation unit capacity of SAPP}
RES(z)	{reserve margin % for each region}
RES(z)	{reserve margin % for each region}
RESsapp /0.10/	{sapp reserve margin}
UFORHN /0.120/	{UFOR for new hydro plants}
UFORNCC(z,ni)	
UFORNLC(z,ni)	
UFORNSC(z,ni)	
UFORNT(z,ni)	

(6) sixhr.inc

july2497(th,z)	Hourly System load on July 24 1997
july2497(th,z)	Hourly System load on July 24 1997
july2497(ts,td,th,z)	Hourly System load on July 24 1997
Mtod(th) /	
PeakD(ty,z)	
PeakD(ty,z)	{peak demand for each region in each year}
PeakD(ty,z)	{peak demand for each region in each year}

(7) Uncertain.inc

Fdrought(ty)	{reduced water flow during drought; 1 = normal <1 is dry}

(8) Sapp.gms

*equation con11b	
*equation con12	
*equation con12b	{only two large coal units per period}
*equation con13	
*equation con13b	
*equation con14	
*equation CON7	{new combined cycle plants expansion limit}
*equation CON8	{new large coal plants expansion limit}
*Integer variables HNVexp(ty,z,nh)	{Variable Capacity of new hydro}
*Integer variables HOVexp(ty,z,ih)	{Variable Capacity of Old hydro}
{Construction cost for interconnectors}	
{Expansion cost for old interconnectors}	
{Power flow along New line (MW)}	
{power level for new combined-cycle}	
{power level for new large coal plants}	
{power level for new small coal plants}	
{power level for new turbine}	
{Variable Capacity of new Interconnectors}	
{Variable Expansion of Old Interconnectors}	
Binary variable YCC(tya,z,ni)	{decision of new combined-cycle plants}
Binary variable Yph(ty,z,phn)	
binary variables Yh(ty,z,nh)	{construction of hydro}
binary variables Ypf(ty,z,zp)	{construction of new interconnectors}
Binary variables YLC(tya,z,ni)	{decision of new large coal plants}
Binary variables YSC(tya,z,ni)	{construction of new small coal plant}
equation BUDGETmax	
equation BUDGETmin	
Equation CapcostH	{New Hydros CapitaL cost}
Equation CapcostHO	{Old hydros Capital Cost}

Equation CapcostPF	{New Tie lines Capital cost (PW)}
Equation CapcostPFO	{Old Lines PW Capital cost}
Equation CapcostPH	{New Pumped Hydros Capital cost}
equation CON10	{old thermo plants expansion limit}
equation con11	
equation con15	
equation con15a	
equation CON1a	{new gas turbine generation limit of off-peak day}
equation CON1b	{new gas turbine generation limit of peak day, summer}
equation CON1c	{new gas turbine generation limit of peak day, winter}
equation CON1d	{new gas turbine generation limit of average day}
equation CON2a	{new combined cycle generation limit of off-peak day}
equation CON2b	{new combined cycle generation limit of peak day, summer}
equation CON2d	{new combine cycle generation limit of average day}
equation CON3a	{new small coal generation limit of off-peak day}
equation CON3b	{new small coal generation limit of peak day, summer}
equation CON3c	{new small coal generation limit of peak day, winter}
equation CON3d	{new small coal generation limit of average day}
equation CON4a	{new large coal generation limit of off-peak day}
equation CON4b	{new large coal generation limit of peak day, summer}
equation CON4c	{new large coal generation limit of peak day, winter}
equation CON4d	{new large coal generation limit of average day}
equation CON4d	{new large coal generation limit of average day}
equation CON5	{expansion can be put only after construction}
equation CON5	{expansion can be put only after construction}
equation CON6	{expansion can be put only after construction}
equation CON7	{expansion limit for gas turbine}
equation CON8	{expansion limit for small coal}
equation CON9a	{old thermo plants generation limit of off-peak day}
equation CON9b	{old thermo plants generation limit of peak day, summer}
equation CON9c	{old thermo plants generation limit of peak day, winter}
equation CON9d	{old thermo plants generation limit of average day}
equation CONCOST1	{expansion costs of old thermo plants}
equation CONCOST2	{construction & expansion costs of new thermo plants}
EQUATION Demand	
Equation HN_one	{only one dam per site}
Equation Hnmust	{Enforce fixed cost in new hydros}
EQUATION HNmw	{New hydros MW capacity}
EQUATION HOlimit	{Old hydros maximum additional Capacity limit}
EQUATION MWhDam	{Annual MWh capacity limit for Dams }
EQUATION MWhODam	{Annual MWh capacity limit for Existing Dams}
EQUATION MWhror	{New run of river hydros MWh Capacity limit}
Equation Newpumped	
Equation Oldpumped	
EQUATION PFNdirect	{enforce expansion in "zp,z" direction}
Equation PFNmust	{Incur fixed cost before doing any expansion}
EQUATION PFNmw	{New interconnectors MW capacity Limit}
EQUATION PFOdirect	{enforce expansion in other direction}
EQUATION PFOlimit	{Old interconnectors maximum additional Capacity limit}
EQUATION PFOmw	{Old interconnectors MW capacity Limit}
Equation PHN_one	{only one pumped hydro per site}
EQUATION PHNmw	{New pumped hydros MW capacity}
Equation PHOmw	
EQUATION ResvREG2	
EQUATION ResvREG3	
EQUATION ResvREG4	

```
EQUATION Ypfdirect          {enforce construction in "z,zp" direction}
EQUATIONS objf

HNVexp.FX('yr1',z,nh) = 0                          {no expansion in year 1}
HOVexp.FX('yr1',z,ih) = 0                          {no construction in year 1}
Integer variables PGNCCexp(tyb,z,ni)               {expansion of new combined-cycle}
Integer variables PGNLCexp(tyb,z,ni)               {expansion of new large coal}
Integer variables PGNSCexp(tyb,z,ni)               {expansion of new small coal plant}
Integer variables PGNTexp(tyb,z,ni)                {expansion of new gas turbine plants}
Integer variables PGOexp(tyb,z,i)                  {expansion of old thermo plants}
Parameter Dyr(ty,ts,td,th,z)
parameter fday(td)                                 {Day factor}
parameter fseason(ts)/
Parameter Mday(td)                                 multiplier of days in a season
parameter Mperiod(ty)                              multiplier of year

parameter opPG, opPGNT, opPGNCC, opPGNSC, opPGNLC, opUE, opwater

PFNVexp.FX('yr1',z,zp) = 0                         {no expansion in year 1}
PFOVexp.FX('yr1',z,zp) = 0                         {no expansion in year 1}
PGNCCexp.FX('yr1',z,ni) = 0                        {no expansion in year 1}
PGNLCexp.FX('yr1',z,ni) = 0                        {no expansion in year 1}
PGNSCexp.FX('yr1',z,ni) = 0                        {no construction in year 1}
PGNTexp.FX('yr1',z,ni) = 0                         {no construction in year 1}
PGOexp.FX('yr1',z,i) = 0                           {no expansion in year 1}
Positive variable HNcapcost(ty)                    {Construction cost for hydros}
Positive variable Hnew(ty,ts,td,th,z,nh)           {New Hydro MW output}
Positive variable HNVexp(ty,z,nh)                  {Variable Capacity of new hydro}
Positive variable HOcapcost(ty)                    {Expansion cost for old hydros}
Positive variable PFNcapcost(ty)
Positive variable PFnew(ty,ts,td,th,z,zp)
Positive variable PGPSN(ty,ts,td,th,z,phn)
Positive variable PGPSO(ty,ts,td,th,z)
Positive variable PGPSO(ty,ts,td,th,z)
Positive Variable PHNcapcost(ty)
Positive variable PUPSN(ty,ts,td,th,z,phn)
Positive variable PUPSO(ty,ts,td,th,z)
Positive variable PUPSO(ty,ts,td,th,z)
Positive variable YT(tya,z,ni)                     {decision of new gas turbine plants}
Positive variables H(ty,ts,td,th,z,ih)             {Generation level MW - Hydros}
Positive variables PGNcapcost(ty)                  {expansion costs of new thermo}
Positive variables PGOcapcost(ty)                  {expansion costs of old thermo}
Positive variables HOVexp(ty,z,ih)                 {Variable Capacity of Old hydro}
Positive Variables PF(ty,ts,td,th,z,zp)            {power flow MW}
Positive variables PFNVexp(ty,z,zp)
Positive variables PFOcapcost(ty)
Positive variables PFOVexp(ty,z,zp)
Positive Variables PG(ty,ts,td,th,z,i)             {power level for old plants}
Positive variables PGNCC(ty,ts,td,th,z,ni)
Positive variables PGNCCexp(tyb,z,ni)              {expansion of new combined-cycle}
Positive variables PGNLC(ty,ts,td,th,z,ni)
Positive variables PGNLCexp(tyb,z,ni)              {expansion of new large coal}
Positive variables PGNSC(ty,ts,td,th,z,ni)
Positive variables PGNSCexp(tyb,z,ni)              {expansion of new small coal plant}
Positive variables PGNT(ty,ts,td,th,z,ni)
Positive variables PGNTexp(tyb,z,ni)               {expansion of new gas turbine plants}
```

```
Positive variables PGOexp(tyb,z,i)              {expansion of old thermo plants}
positive variables UE(ty,ts,td,th,z)            {Unserved energy}

Scalar DecayHNdecay       rate of new hydro       /0.001/
Scalar DecayHOdecay       rate of old hydro       /0.001/
Scalar DecayNCCdecay      rate of combined cycle          /0.001/
Scalar DecayNLCdecay      rate of large coal      /0.001/
Scalar DecayNSCdecay      rate of small coal      /0.001/
Scalar DecayNTdecay       rate of gas turbine     /0.001/
Scalar DecayPFNdecay      rate of new lines       /0.000/
Scalar DecayPFOdecay      rate of old lines       /0.000/
Scalar DecayPGOdecay      rate of old thermo      /0.001/
Scalar DW                 weight of decay year    /2/
scalar tsT                number of seasons in an year
YCC.FX('yr1',z,ni) = 0    {no construction in year 1}
Yh.FX('yr1',z,nh) = 0     {no construction in year 1}
YLC.FX('yr1',z,ni) = 0    {no construction in year 1}
Ypf.FX('yr1',z,zp) = 0    {no construction in year 1}
```

CHAPTER 1

BACKGROUND TO THE USER MANUAL

This user manual is written as a consequence of the July 1998 modeling workshop in Cape Town , South Africa. Delegates at that workshop, from the national utilities of the Southern African Power Pool (SAPP), requested that this be written in order to help future users of the SAPP long-term electricity trading model. Funding for this work has been provided by USAID, under it's EAGER program, (Equity and Growth Through Economic Research).

The manual has been written by Professor F.T. Sparrow and assisted by members of Purdue University's State Utility Forecasting Group (SUFG) of which he is the director. It describes how to use of the SAPP long-term model which has culminated from two years of joint research between the member utilities of SAPP and Purdue University 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 (Zaire)
Tanesco	Tanzania Electric Supply Company
Zesa	Zimbabwe Electricity Supply Authority
Zesco	Zambia Electricity Supply Corporation

The long-term model is a mixed integer mathematical program which, using the GAMS and CPLEX software, minimizes the total costs (capital, fuel, operational and maintainance, and unserved energy) for the capacity expansion of the SAPP up to the year 2020.

The long-term model includes decision variables –

"to build or not to build?"
"to expand or not to expand?"
"to make or buy"

Involving:

- 600 integer variables
- 500,000 continuous variables
- 20,000 constraints

The objective function of the long-term model is to minimize the costs of generating and transmission capacity expansion in the SADC region over a 20 year time horizon:-

(a) If SAPP were to choose the generation/expansion plan to minimize total SAPP costs.

(b) If each country chooses to meet domestic demand only from domestic power sources.

<u>LT Model Objective Function</u>

Minimize Total Cost (present value)

{ ∑ Capital Costs of Extensions & New sites (Large Coal, Small Coal, Combined Cycle, Hydro, Pumped Hydro, Transmission lines)

+ ∑ Fuel Costs + ∑ Operations and Maintenance Costs + ∑ Unserved Energy}

Many user options allowed in the model: A few of the major options available include:

- Planning horizon options
- Reliability options
- Demand characterization options
- Financial options (cost of capital etc)
- Supply options

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

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

PentiumII BX 100 MHz motherboard,

PentiumII 350 MHz processor,

512 Mb 100 MHz RAM,

961g UW SCSI hard drive.

The long-term (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 and the grid interconnections that exist in the ST model are shown below in Tables 1.1, 1.2, 1.3.

Table 1.1 SAPP Thermal Generation Data for Existing Plants

Country & Station Name	PGmax (MW)
Angola	113
Botswana	118
Mozambique	
Beira	12
Maputo	62
Namibia	
Vaneck	108
Paratus	24
Zimbabwe	
Hwange	956
Munyati	80
Harare	70
Bulawayo	120
Swaziland	9

Country & Station Name	PGmax (MW)
RSA	
Arnot	1320
Duvha	3450
Hendrina	1900
Kendal	3840
Kriel	2700
Lethabo	3558
Majuba	1836
Matimba	3690
Matla	3450
Tutuka	3510
Koeberg *	1840
(* Nuclear)	

Table 1.2 SAPP Hydropower Generation Data for Existing Plants

Country & Station Name	Hmax (MW)
Angola	121
	56
	37
	37
	37
DRC	
Inga	1775
Nseki	248
Nzilo	108
Mwadingusha	68
Koni	42
Mozambique	
HCB	2075
Chic-Cor-Mav	81
Namibia	
Ruacana	240
Swaziland	40

Country & Station Name	Hmax (MW)
Malawi	
Knula	214
Tedzani	64
Tedzani	64
RSA	
Gariep	320
Vanderkloof	220
Palmiet #	400
Drakensbur#	1000
Zimbabwe	
KaribaSouth	666
Zambia	
KaribaNorth	600
Kafue	900
Victoria	100
(# Pumped)	

The new stations that are to 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 1.4.

Table 1.3 SAPP International Transfer Capabilities, PFmax(z,zp), with HCB Revised - March 1998 (Underlined)

	Bots	Les	Nmoz	SMoz	Nam	NSA	SSA	Swaz	DRC	Zam	Zim
Bots						215					350
Les						80					
Nmoz						1800					550
Smoz						250					
Nam							120				
NSA	350	80	0	120			6000	150			350
SSA					210	6000					
Swaz						150					
DRC										250	
Zam									250		1200
Zim	215		540			280				1200	

Source: Power Grid Consulting, Machiel Coetzee, Lusaka, March 1998

The demand for the countries in the ST model is shown in Figures 1.1, 1.2, 1.3. Demand data in the LT model is also based on this demand data but multipliers are employed to allow for different days, seasons, and years.

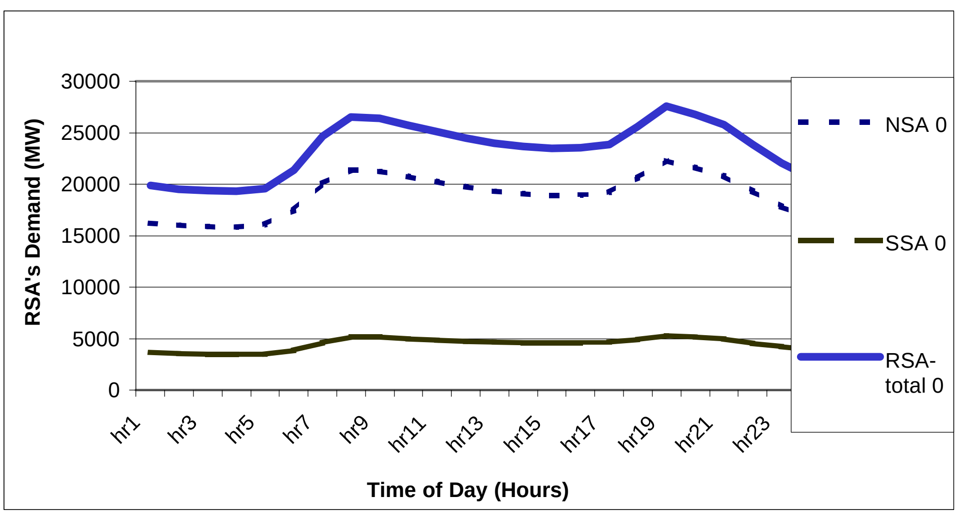


Figure 1.1 Republic of South Africa's Demand (MW), July 24, 1997

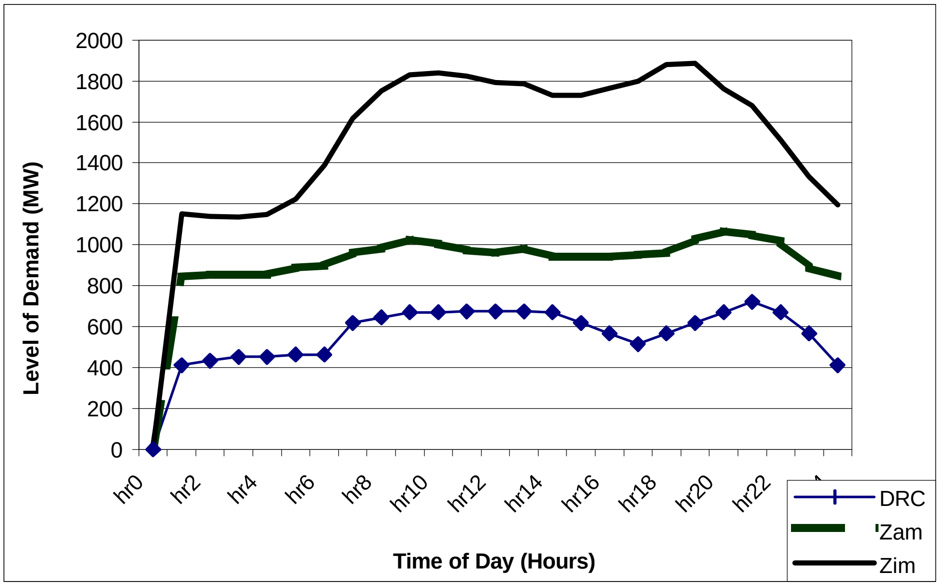


Figure 1.2 Demand for Democratic Republic of Congo, Zambia and Zimbabwe, July 24, 1997

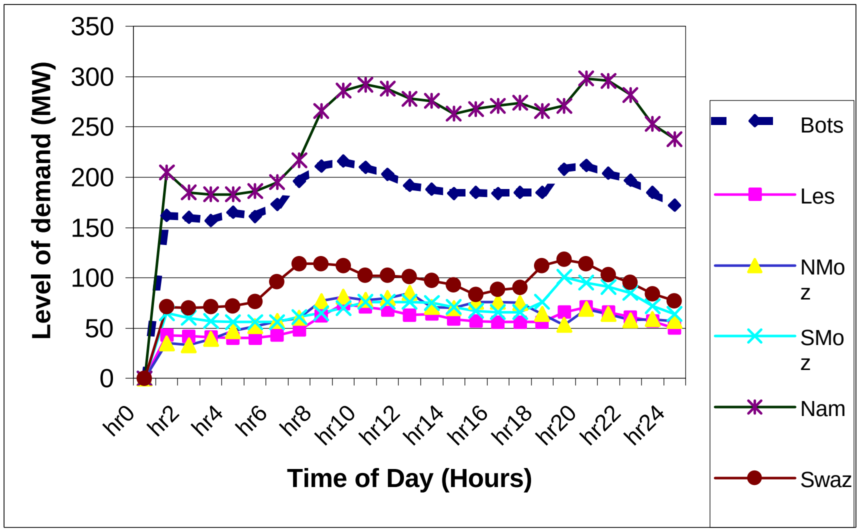


Figure 1.3 Demand for Botswana, Lesotho, Mozambique, Namibia, and Swaziland, July 24, 1997

The formulation for the long-term model is more complex and puts greater demand on the computing requirements compared with the short-term model. The data collection is crucially important. Generation capacity expansion projects are defined by the SAPP in Table 1.4. These show both the hydro and thermal stations that are planned for the region.

Table 1.4 Optional New SAPP Generating Capacity

(A Revision of Year 2 Interim Report Appendix V, - January 29, 1999)

Country	Powerstation	# of Units	Unit Size (MW)	Total Added MW)	Cost $ million	Type T/H/PS	Cost $/kW	HR Btu/ KWh	Fuel $/ MWh	O & M Cost $/MWh
	Optional Projects									
Angola	Cambambe (Ext.)	2	45	90		H				
Angola	Capanda II	2	130	260	300	H	1153			
Botswana	Moropule (Ext.)	2	120	240	420	T	1750			
DRC	Inga 3			3500	4900		1400**			
DRC	Grand Inga ST1			4750	9780	H	2059			
DRC	Grand Inga ST2			4750	6330	H	1332			
DRC	Grand Inga ST3			4750	6120	H	1288			
DRC	Grand Inga ST4			4750	6070	H	1278			
Lesotho	Muela	3	24	72	58	H	805			
Malawi	Kaphichira Phase1 *	2	32	64	—	H				
Malawi	Kaphichira Phase 2	2	32	64	24	H	375			
Malawi	Lower Fufu	2	45	90	119	H	1322			
Malawi	Mpatamanga	5(?)	63(?)	315	335	H	1063			
Malawi	Kholombidzo	2	35	70	330	H	4714			
Mozambique	Mepanda Uncua	5	400	2000	2800	H	1400***			
Mozambique	Cah. Bassa N. (Ext.)			1240	1054	H	850			
Namibia	Kudu (Gas)	1	750	750	650	T	866			
Namibia	Epupa	1(?)	360	360	408	H	1133			
South Africa	Komati A (Recomm).	5	5x90	450	125	T	277	12876	5.154	5.416
South Africa	Grootvlei (Recomm).	6	5x190+1x 180	1130	123	T	109	12186	7.673	4.236
South Africa	Komati B (Recomm).	4	4x110	440	238	T	542	12876	6.026	0.68
South Africa	Camden (Recomm).	8	190	1520	164	T	108	12186	5.855	4.122
South Africa	PB Reactor	10	100	1000	844	T	844	7583	3.4	0.2
South Africa	Lekwe	6	659	3950	4056	T	1027	9890	4.119	0.6
South Africa	Pumped Storage A	3	333	999	373	PS	374			
South Africa	Pumped Storage B	3	333	999	377	PS	378			
South Africa	Pumped Storage C	3	333	999	379	PS	380			
South Africa	High head UGPS	2	500	1000	237	PS	237			
South Africa	Gas Turbine	4	250	1000	324	T	324	9478	58.66	0.646
Tanzania	Ubungo (Gas)	1	40	40	24	T	600	9045	25.6	3.405
Tanzania	Tegeta (Gas)	10	10	100	90	T	900	11055	140.0	
Tanzania	Kihansi	3	60	180	270	H	1500			
Tanzania	Rumakali	3	74	222	439	H	1977			
Tanzania	Ruhudji	4	89.5	358	515	H	1438			
Zambia	Itezhi-Tezhi	2	40	80	74	H	927			
Zambia	Kafue Lower	4	150	600	450	H	750			
Zambia	Batoka North	4	200	800	898	H	1122			
Zambia	Kariba North (Ext.)	2	150	300	223	H	743			
Zimbabwe	Hwange Upgrade	1	84	84	130	T	1547			
Zimbabwe	Hwange 7 & 8	2	300	600	554	T	923	9574	3.427	
Zimbabwe	Gokwe North	4	300	1200	960	T	800	9248	3.023	
Zimbabwe	Batoka South	4	200	800	898	H	1122			
Zimbabwe	Kariba South (Ext.)	2	150	300	200	H	667			
	Commited Projects									
South Africa	Majuba*	6	3x6123x6 67	3837	—	T		10340	5.734	0.495
South Africa	Arnot 3-6 Recomm.*	4	4x330	1320	—	T		10185	3.223	0.718

*Commissioned by 2000, ** Estimated, ***Estimated and assumed given 664 did not include

The long-term (LT) model also includes new generic generating stations. These include large coal stations, small coal station, combined cycle stations and gas turbines. 1998 USA costs and performance data are used for these.

- The generic large coal stations of 500 MW, have net heat rates of 9800 Btu/kWh, initial costs of $582 million, O & M costs of $0.0067/kWh and additional MW can be added at $866/kW. They are capable of running 7446 hours/year at full load.
- The small coal plants of fixed capacity 300 MW have a heat rate of 9800 Btu/kWh, initial costs of $430 million and O & M costs of $0.0089/kWh. They are capable of running 7446 hours/year at full load.
- The combined cycle combustion turbine plants of 250 Mw capacity have a net heat rate of 7490 Btu/kWh, initial costs of $109 million, O & M costs of $0.0042/kWh and additional MW added at a cost of $412/kW. These plants can be expanded up the maximum value of 1000 MW. They are capable of running 7446 hours/year at full load.
- The addition of 100 MW hydro turbines to existing hydro sites costs $880/kW to purchase and install.
- Small fixed capacity 50 MW simple-cycle advanced combustion turbines, with a heat rate of 11,250 Btu/kWh, have a total capital cost of $15 million, and O & M costs of $0.86/kWh. They are capable of 1752 hours/year at full load (turbo power FT8 twin).

The 1997 ST model included the existing nine interconnected countries of SAPP but the 1998 LT model includes all 12 countries of the SAPP. The LT model interconnects the three remaining countries, Angola, Malawi and Tanzania to SAPP grid (Figure 1.4).

The new international lines that are committed for the year 2000 are listed in Table 1.5.

The line capacities were supplied mainly by Eskom. Further long-term transmission lines are also shown in Table 1.6. These values have been supplied by other SAPP utilities. With an average demand growth rate of 4% for the region and over a 20 year period it will mean that electricity supplies will have to more than double. Large scale trade will not be possible unless there is a major expansion in these international lines.

Figure 1.4 SAPP-Purdue Electricity Trade Models

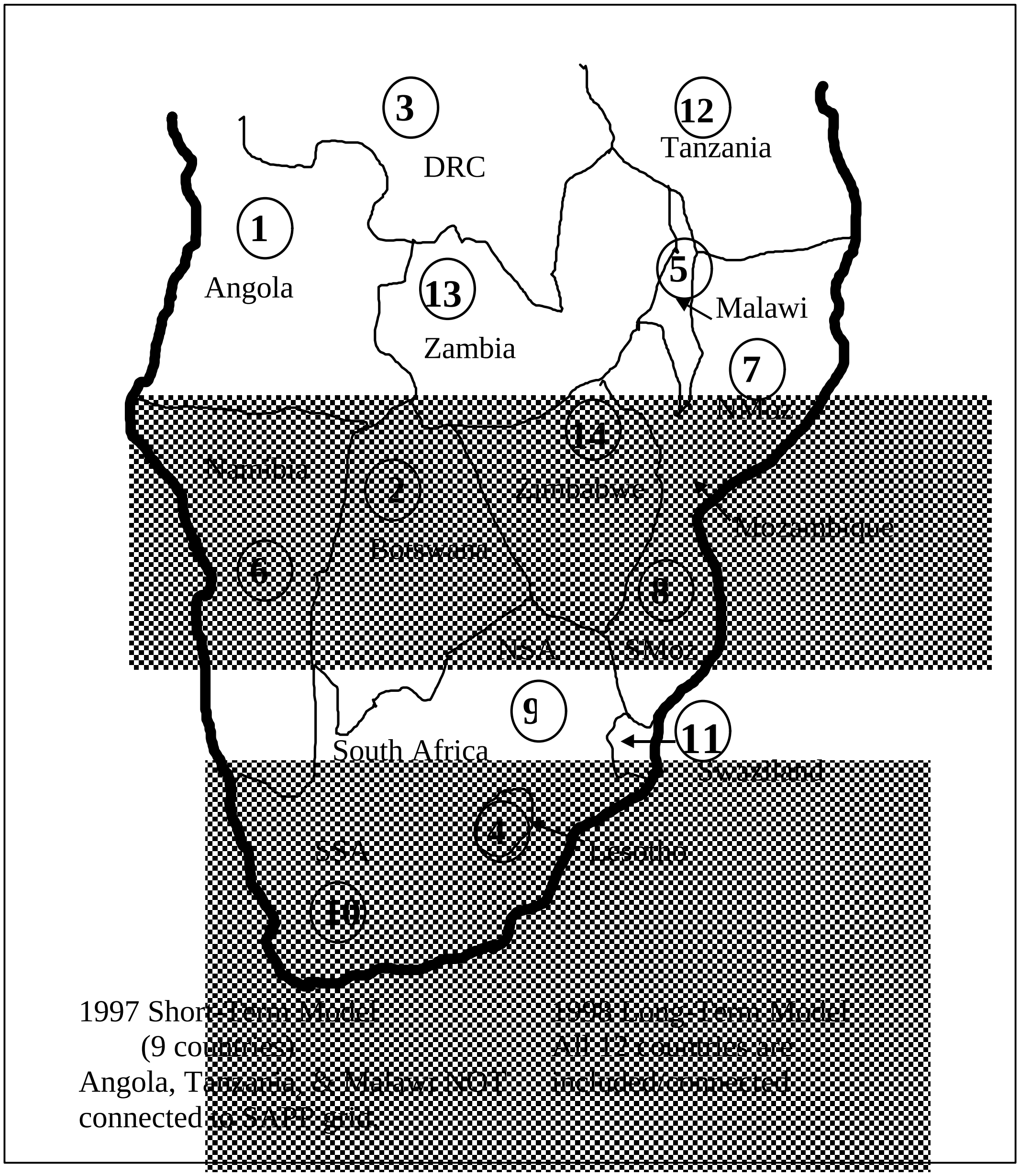


Table 1.5 SAPP International Maximum Practical Transfer Capacities Existing or Committed for the Year 2000

	Ang	Bots	DRC	Les	Mal	Nam	NMoz	SMoz	NSA	SSA	Swaz	Tan	Zam	Zim
Ang														
Bots									850					650
DRC													320	
Les									130					
Mal														
Nam										700			40	
Nmoz														550
Smoz									1400		1200			
NSA		850		130			2000	1400		3500	1400			
SSA						700			3500					
Swaz								1200	1400					
Tan													180	
Zam			320			40						180		1200
Zim		650					550		500				1200	

Source: Eskom Data Sheet, IEP6, Oct7,1998

Table 1.6 SAPP International Transfer Capacity Options for 2000 - 2020

	Ang	Bots	DRC	Les	Mal	Nam	NMoz	SMoz	NSA	SSA	Swaz	Tan	Zam	Zim
Ang			2000			2000								
Bots														
DRC	2000												1000	
Les														
Mal													240	
Nam	2000													
Nmoz								1600						
Smoz							1600							
NSA														
SSA														
Swaz														
Tan														
Zam			1000		240									
Zim														

Source: SAPP_Purdue Modeling Workshop, Cape Town, July 1998

Following this background chapter to the user manual are more three chapters that cover:

- A simplified long-term trade model,
- Operation instructions for the LT model, and
- Detailed description of the LT model.

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 variables 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.

CHAPTER 2

THE LONG-RUN MODEL IN SIMPLE, MODULAR FORM

2.1 Introduction

Figure 2.1 shows the simplified version of the SAPP network used to model the short-term potential for additional trade 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 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 – based on SAPP-wide demand on one day: July 24, 1997 – 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;

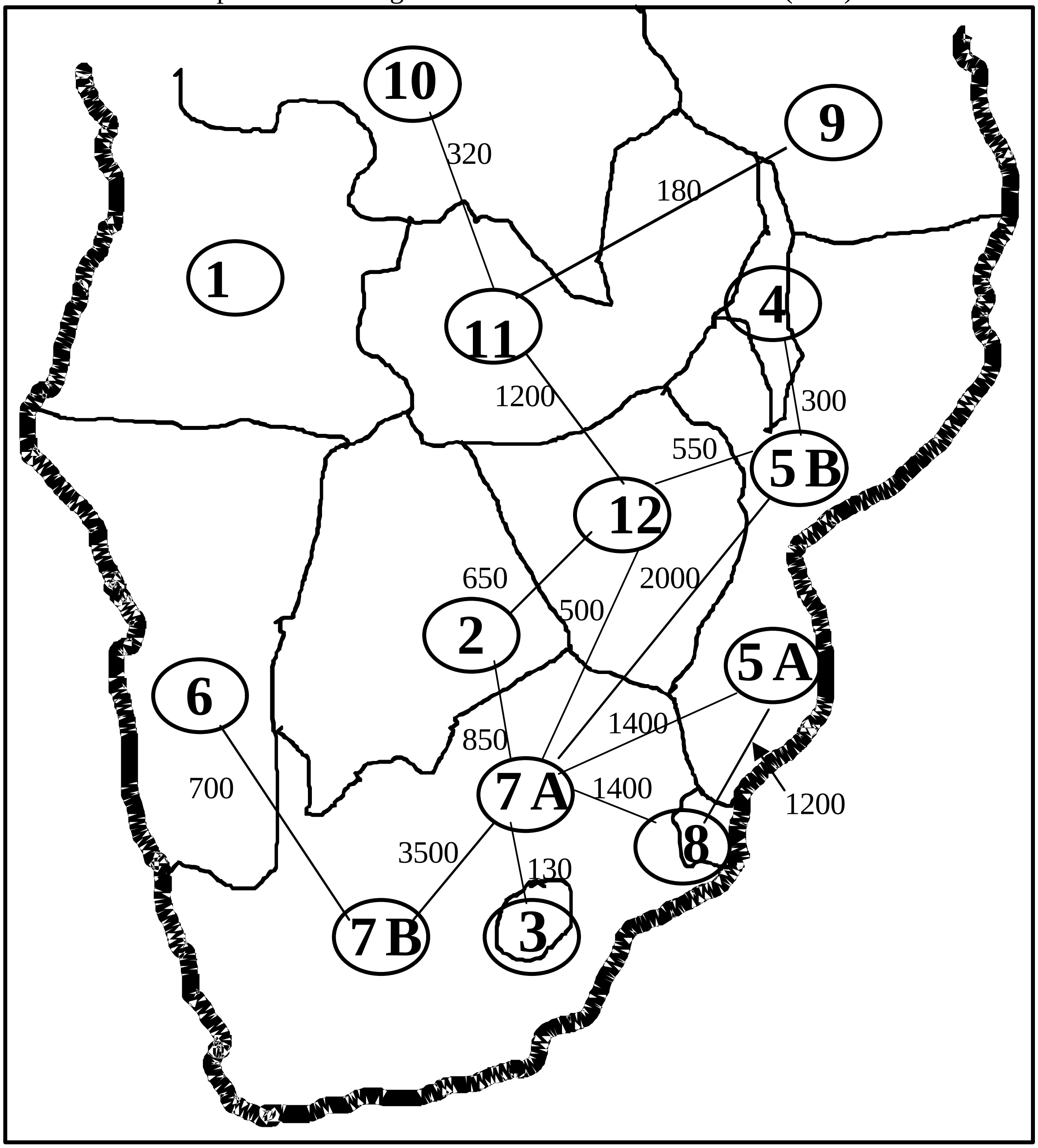
(d) System spinning reserve requirements;

(e) Constraints which require 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 2.1 SAPP International Maximum Practical Transfer
Capacities Existing or Committed for the Year 2000 (MW)



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*

Note: lines connecting DRC to Zambia and N. Mozambique to N S. Africa are one way DC; the rest are AC.

The near radial nature of the network in Figure 2.1 plus the fact that many lines from the hydro plants will be DC lines suggested that the modelers could 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 detail, 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 "long-run" model of the type developed below which allows such expansion as part of the optimization.

The long-run 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 a 20-year horizon 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.

2.2 Overview of the Model Use

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: Fixed trade mode; all "PF(t,y,z,zp)" are set at existing 1997 levels, forcing each country to provide for growth in their own demands by constructing their own capacity. Table "PFfix(z,zp)" below gives the trade amounts used in mode 1.

Mode 2: Free-trade mode; the "PF(t,y,z,zp)" are free to find the mix of domestic production, imports and exports that minimize SAPP-wide operating and construction costs.

The long-run model has 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 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 long-run 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 long-run model computationally feasible for PC use:

(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 multi-hour periods of varying length, plus a peak hour.

Added to the model are constraints and variables which capture:

- The present value of the new equipment and operating costs over the 20-year 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 day type over the 20-year planning horizon (modeled as 5 two-year periods followed by 2 five-year periods) used in the model, under three growth scenarios – low, high, and expected.
- 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.
- “Off the shelf” plants of varying capacity based on the latest U.S. data:
  - a) A 50 MW simple cycle gas turbine;
  - b) A combined-cycle gas turbine whose capacity can vary from 250 to 1000 MW, in 250 MW increments;
  - c) A small (300 MW) fixed capacity sub-critical coal unit;
  - d) A pulverized coal steam turbine whose capacity can vary from 500 to 3500 MW, in 500 MW increments.
  - e) “Off-the-shelf” water turbines for installation at exiting hydro sites.
- 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 shown in Figure 2.2, to include new and expanded hydro projects in DRC, Mozambique (two sites), Zimbabwe (two sites), Namibia, Tanzania, and Angola (rehabilitation), and new and expanded thermal projects in RSA, Namibia, Zimbabwe, Botswana, Tanzania, and Angola (rehabilitation).

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, Mozambique, and the Democratic Republic of the Congo are represented by two demand nodes each rather than one.

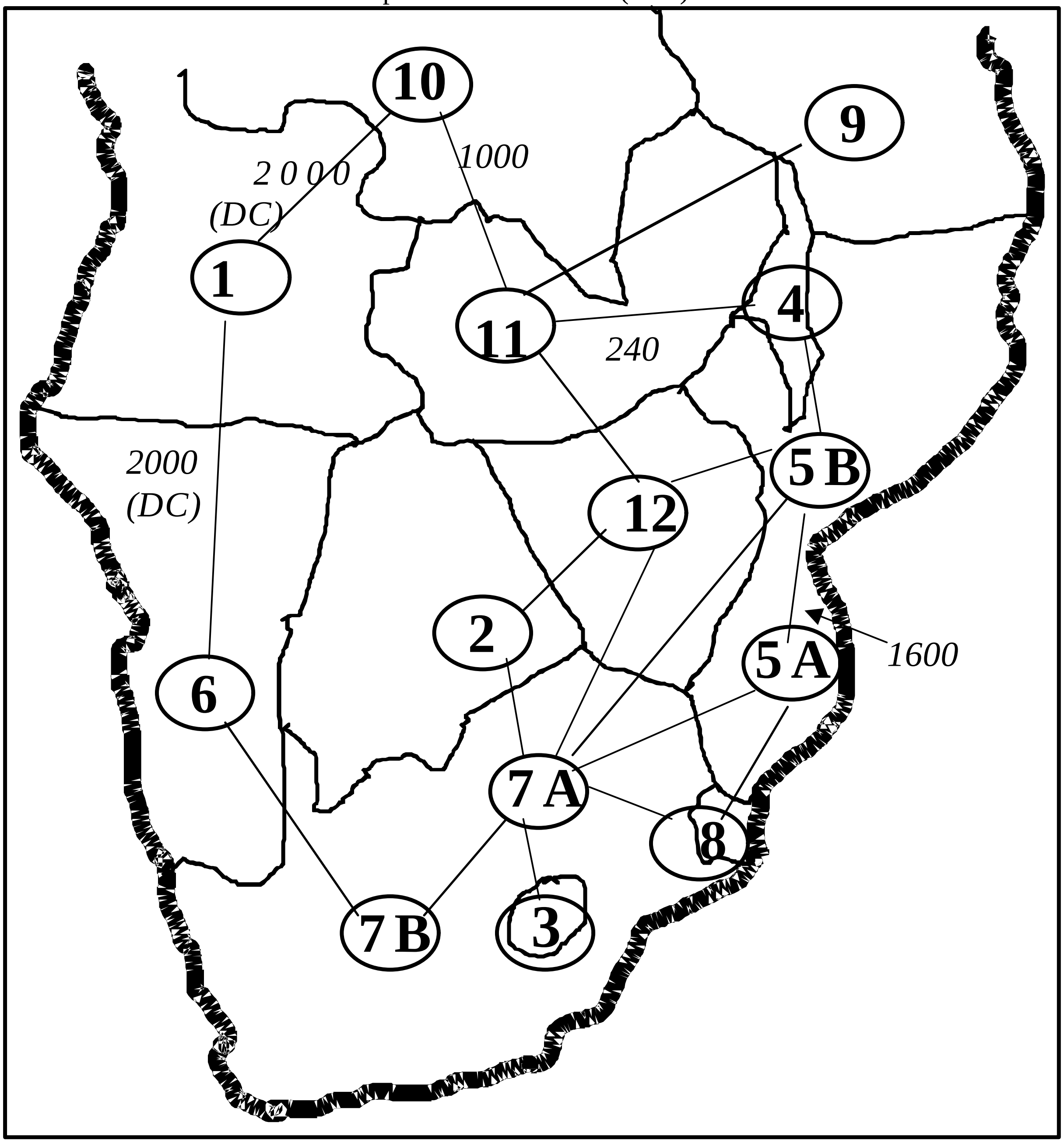
For each of the time-weighted representative hours in a time-weighted given day type in a given year, the model dispatches the energy from plants on line in that year to meet hourly demand at least system cost – e.g., imports/exports enter the solution if the system optimization finds it cheaper to trade 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.

Figure 2.2 SAPP International Transfer Proposed Initial Capacity
Options for after 2000 (MW)



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 2.1 SAPP International Transfer Capabilities in March 1998

	Bots	DRC	Les	NMoz	SMoz	Nam	NSA	SSA	Swaz	Zam	Zim
Bots							215				350
DRC										250	
Les							80				
Nmoz							1800				550
Smoz							250				
Nam								120			
NSA	350		80	0	120			6000	150		350
SSA						210	6000				
Swaz							150				
Zam		250									1200
Zim	215			540			280			1200	

Source: Power Grid Consulting, Machiel Coetzee, Lusaka, March 1998

Table 2.2 SAPP International Maximum Practical Transfer Capacities Existing or Committed for the Year 2000

	Ang	Bots	DRC	Les	Mal	Nam	Nmoz	SMoz	NSA	SSA	Swaz	Tan	Zam	Zim
Ang														
Bots									850					650 *5
DRC													320 *9	
Les									130					
Mal														
Nam										700 *2			40 *3	
NMoz														550 *7
SMoz									1400 *6		1200 *8			
NSA		850		130			2000	1400 *6		3500	1400 *1			
SSA						700*2			3500					
Swaz								1200 *8	1400*1					
Tan													180 *4	
Zam			320 *9			40*3						180 *4		1200 *10
Zim		650 *5					550 *7		500				1200 *10	

Source: Eskom Data Sheet, IEP6, Oct7,1998

*1 = There is a small discrepancy between Eskom's and SEB's data sets 1400 MW vs 1340 MW
*2 = There is a discrepancy between Eskon's and Nampower's data sets 700 MW vs 900 MW
*3 = These 2 lines (5 + 35 MW) are listed in ZESCO's data set but not in Nampower's data set
*4 = There is a small discrepancy between ZESCO's and Tanesco's data sets 280 MW in 2001 vs 200 MW in 2000 (earliest)
*5 = Source: Eskom data set, no info available in BPC or ZESA data sets
*6 = There is a small discrepancy between Eskom's and EdM's data sets 1400 MW vs 1312 MW
*7 = Songo Bindura line, from Eskom's data files, not listed in Zesa's and EdM's data sets
*8 = there is a small discrepancy between SEB's and EdM's data sets 1200 MW vs 1312
*9 = There is a small discrepancy between ZESCO's and DRC's data sets 320 MW vs 340 MW
10* = No transmission data receoved from ZESA

Table 2.3 SAPP International Transfer Capacity Options for 2000 - 2020

	Ang	Bots	DRC	Les	Mal	Nam	NMoz	SMoz	NSA	SSA	Swaz	Tan	Zam	Zim
Ang			2000			2000								
Bots														
DRC	2000												1000	
Les														
Mal													240	
Nam	2000													
Nmoz								1600						
Smoz							1600							
NSA														
SSA														
Swaz														
Tan														
Zam			1000		240									
Zim														

Source: SAPP_Purdue Modeling Workshop, Cape Town, July 1998

2.3 The Model in Simple Modular Form

By eliminating the detailed treatment of time – simply "t" in this section – generation equipment characterization and identification - simply "i" in this section – and the modeling compromises made to reduce running time, the model can be stated quite compactly. Parameters are over-lined, variables are not.

2.4 The Supply - Demand Module

The requirement that demand be met in each time period "t" in year "y" is expressed in the following way: Letting demand (in MW) in country "z" in hour "t" in year "y" be given by the parameter "$\overline{D(t, y, z)}$", regional distribution loss by the term "$\overline{DLC(z)}$" (equal to one plus the distribution loss percent) and the impact of any demand side management program on demand, by the term "$\overline{DSM(t, y, z)}$" the requirement is:

$$\text{Supply, during "t" in year "y" in "z"} = \left[\overline{D(t, y, z)} - \overline{DSM(t, y, z)}\right]\left[\overline{DLC(z)}\right]$$

Supply during "t" in "y" in "z" can be provided by production from plant "i" in "z", given by "PG(t,y,z,i)" plus net power inflows (e.g., imports less exports). Letting "$\overline{Ploss(zp, z)}$", a parameter, be the power loss factor for transmission from "zp" to "z", and

"PF(t,y,zp,z)", a variable, be power flow from "zp" to "z" in hour "t" in year "y", and "UE(t,y,z)" be unserved energy during hour "t" in year "y" in country "z", the requirement that demand equal supply in region "z" becomes:

$$\overbrace{\sum_{i} PG(t,y,z,i)}^{\text{total domestic production}} + \overbrace{\sum_{zp} PF(t,y,zp,z)\overline{(1-Ploss(zp,z))}}^{\text{total delivered imports}} - \overbrace{\sum_{zp} PF(t,y,z,zp)}^{\text{total exports}} + \overbrace{UE(t,y,z)}^{\text{unserved energy}}$$

$$(1) \quad = \left[\overbrace{\overline{D(t,y,z)}}^{\text{domestic demand less DSM}} - \underbrace{\overline{DSM(t,y,z)}}_{\text{impact of DSM}} \right] \left[\overline{DLC(z)} \right] \quad \text{for all t, y, and z}$$

2.5 The Capacity Constraint Module

2.5.1. Generation

At any time, power generation "PG(t,y,z,i)" by plant "i" must not exceed plant "i's" available capacity in year "y". Letting "PGinit(z,i)" be initial capacity, and "PGexp(y,z,i)" be the decision variable for new capacity expansion available in "y" at "i", it must be true that generation cannot exceed capacity installed by year "y" e.g.

$$PG(t,y,z,i) \le \overline{PGinit(z,i)} + \sum_{\tau=1}^{y} PG\exp(\tau,z,i) \quad \text{for all t,y,and z}$$

If it is assumed that new capacity can only by added by purchasing additional units of a fixed size, "PGexp(y,z,i)" is equal to the integer decision variable "Y(y,z,i)"=0,1,2,etc. - giving the number of new units of fixed size added at site "i" in "z" during year "y" — times the MW capacity of each unit given by the parameter "expstep(z,i)";

$$PG\exp(y,z,i) = Y(y,z,i)\overline{expstep(z,i)}$$

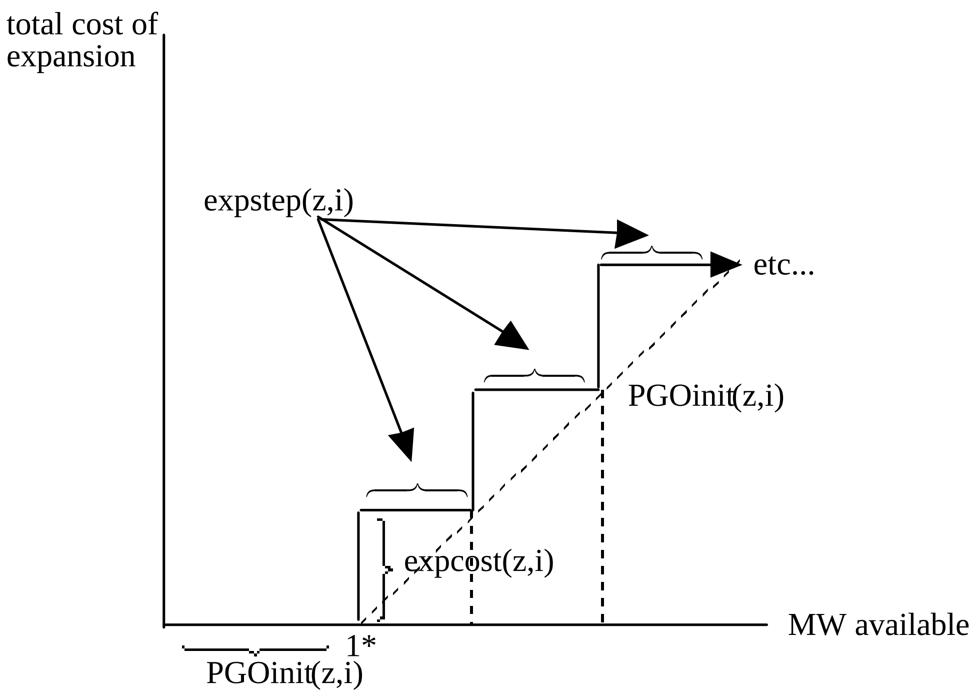
While the "lumpy" nature of capacity additions is a fact of life, the assumption comes with a very substantial running time penalty. The alternative is to model capacity expansion as a continuous variable, and then round off the answer to the nearest available unit size, which brings with it the reverse set of characteristics - quick run time, but the possibility of round off error.

The choice of how each of the capacity expansion decisions is to be modeled is left up to the user; the choice is made by declaring the variable "Y(y,z,i)" an integer variable (0,1,2,3, etc.) if the "lumpy" assumption is to be made, or declaring "Y(y,z,i)" a positive value (≥ 0) if the continuous assumption is made.

All this can be summarized in Figure 2.3 below, which plots the cost of added capacity as a function of the capacity added.

Letting "expcost(z,i)" be the capital cost of unit size "expstep(z,i)", and declaring the variable "Y(y,z,i)" to be integer, the plot would be the solid step line; if "Y(y.z.i)" was a continuous variable, the plot would be the dashed straight line.

Figure 2.3



The full expression for the capacity constraint is then;

$$PG(t, y, z, i) \le \overline{PGinit(z, i)} + \sum_{\tau=1}^{y} Y(\tau, z, i)\overline{expstep(z, i)}$$

with "Y(τ,z,i)" either ≥ 0, if continuous expansion is assumed, or integer valued, if expansion by multiples of plant of fixed size $\overline{expstep(z, i)}$ is chosen.

Next, the gradual decline in a generating unit's capacity needs to be taken into consideration. If the parameter "decay" gives the annual percent decline in the nameplate capacity of a generating unit, the capacity constraint should be written:

$$PG(t, y, z, i) \le \overline{PGinit(z, i)}(1 - Decay)^{y} + \sum_{\tau=1}^{y} Y(\tau, z, i)\overline{expstep(z, i)}(1 - Decay)^{y-\tau}$$

Thus, for year 3, the right hand side of the constraint would be;

$$\overline{PGinit(z,i)}(1 - Decay)^{3} + \overline{exp\,step(z,i)}\big[Y(1,z,i)(1 - Decay)^{3-1} + Y(2,z,i)(1 - Decay)^{3-2} + Y(3,z,i)(1 - Decay)^{3-3}\big]$$

Further, the capacity available must be derated in all hours by the forced outage rate for plant "i" in "z", "FOR(z,i)". Assuming maintenance is performed off-peak, capacity should be derated by both forced and unforced outages "UFOR(z,i)", for off-peak periods. Thus, for peak hours, denoted "peaks", we have:

$$PG(peaks, y, z, i) \le$$

(2a) $$\left(\overline{PGinit(z,i)}(1 - Decay)^{y} + \sum_{\tau=1}^{y} PGexp(\tau.z,i)(1 - Decay)^{y-\tau}\right)\left(1 - \overline{FOR(z, i)}\right) \quad \forall\, peaks, y, z, i$$

and for off-peak hours, denoted off-peaks, we have:

(2b)

$$
\begin{aligned}
&PG(off-peaks, y, z, i) \\
&\le \left(\overline{PGinit(z,i)}(1-Decay)^{y} + \sum_{\tau=1}^{y} PG(\exp(\tau, z, i)(1-Decay)^{y-\tau} \right)(1-\overline{FOR(z,i)})(1)-\overline{UFO(z,i)} \\
&\quad \forall \ offpeaks, y, z, i
\end{aligned}
$$

The above MW capacity constraints hold for hydro and thermal units alike; power from both are constrained by the MW of installed generation capacity. An additional constraint must hold for hydro facilities whose turbines are driven by water flow - that the power generated over a season not exceed the power equivalent of the water allowed to flow into the turbines during the season, a parameter “HROmwh(z,ih)” for run of river, “HDO(z,ih)” for dams. Ideally, SAPP data would provide estimates of “HROmwh(z,ih)” and “HDOmwh(z,ih)” directly; absent such data, the model uses the product of the MW capacity of the dam times a load factor.

The model also contains a user specified parameter “fdrought(ty)”, which can vary by period, which allows the energy available to vary according to the assumptions regarding drought conditions. The default values are all set at 1 in the model; users can vary the parameter to estimate the impact of drought conditions on SAPP expansion plans.

In all cases, letting “T” be the number of hours in a year “y”, we have;

(2c) $$\sum_{\tau=1}^{T} PG(\tau, y, z, ih) \le HROmwh(z, ih) fdrought(y)$$

for run of river, and

2c) $$\sum_{\tau=1}^{T} PG(\tau, y, z, ih) \le HDOmwh(z, ih) fdrought(y)$$

for dams.

2.5.2 Transmission

Power flows in "t" within "y" from "z" to "zp" cannot exceed the installed capacity available during year "y". In a manner analogous to generating capacity, we have, for all periods:

(3)
$$\mathrm{PF}(t,y,z,zp) \le \left[(\mathrm{PFinit}(z,zp)(1-\mathrm{Decay})^{y} + \sum_{\tau=1}^{y} \mathrm{PFexp}(\tau,z,zp)(1-\mathrm{Decay})^{y-\tau} \right](1)-\overline{\mathrm{FOR}(z,zp)}$$

where PFexp(y,z,zp)=Y(y,z,zp)$\overline{\mathrm{expstep}(z,zp)}$, with "Y(y,z,zp)" is the integer variable indicating the number of additions to capacity of fixed size installed in "y", and "$\overline{\mathrm{expstep}(z,zp)}$" the additional MW transmission capacity/unit, and "$\overline{\mathrm{FOR}(z,zp}$)" is the forced outage rate for transmission lines (unforced outage rates are assumed insignificant for these long distance lines).

Since line expansion from "z" to "zp" also expands line capacity from "zp" to "z" (i.e., only one non-directional line links "z" to "zp"), we have:

$$\mathrm{PFexp}(y,z,zp) = \mathrm{PFexp}(y,zp,z)$$

For DC lines, capacity expansion is in one direction only; hence the above equation holds only for AC lines. The costs of such expansion will be split equally between the two directional expansions.

2.6 The Reliability Module

System reliability constraints enter the model by requiring that installed generation capacity, plus imports minus exports during peak periods, always exceeds yearly peak demand (denoted "peak" to indicate the hour in which the largest MW demand takes place during the year) plus a reserve margin. Two methods are used in the model.

The first requires that a source-specific reserve margin "1+$\overline{\mathrm{RES(i)}}$" be maintained for each plant "i", as well as for each source of imports, "1+ $\overline{\mathrm{RESIMP(z)}}$" and exports, "1+$\overline{\mathrm{RESEXP(z)}}$";

$$\sum_{i} \frac{\overline{\mathrm{PGinit(z,i)}}(1-\mathrm{Decay})^{y} + \sum_{\tau=1}^{y} \mathrm{PG\,exp}(\tau,z,i)(1-\mathrm{Decay})^{y-\tau}}{1+\overline{\mathrm{RES(i)}}}$$

4a) $$+ \sum_{zp} \frac{\mathrm{PF(peak,y,zp,z)}(1-\overline{\mathrm{Ploss(zp,z)}})}{1+\overline{\mathrm{RESIMP(z)}}} - \sum_{zp} \frac{\mathrm{PF(peak,y,z,zp)}}{1+\overline{\mathrm{RESEXP(z)}}}$$

$$\geq \left[\overline{\mathrm{D(peak,y,z)}} - \overline{\mathrm{DSM(peak,y,z)}}\right]\left[\overline{\mathrm{DLC(z)}}\right] \quad \forall\ y, z, \mathrm{peak}$$

The inclusion in the reserve margin of exports and imports and the specification of "$\overline{\mathrm{RESIMP(z)}}$" and "$\overline{\mathrm{RESEXP(z)}}$" are at the heart of the model. Some suggest "$\overline{\mathrm{RESIMP(z)}}$" should be a very large positive number (which in effect reduces the impact of imports on the margin in (4a)) to reflect the risk of including imports in the reserve margin. Others argue that it should simply reflect only the uncertainty associated with transmission as well as generation failure – e.g., treat imports as firm power contracts whose interruption is conditional only on forced outage events. Others argue "$\overline{\mathrm{RESEXP(z)}}$" should be 0 to insure the exporter maintains enough generation capacity to cover outages.

Whatever the values assigned, some measure of exports and imports need to be counted in the reserve margin calculation. U.S. utilities routinely enter the electricity trading market to purchase firm power in order to satisfy their reserve requirements, not just their energy requirements; indeed, companies could purchase capacity to meet reserve requirements, yet never use it.

To leave out net imports entirely is clearly a mistake, for if they are left out, the economics of substituting imports for domestic production is biased against imports, since the full cost of imports must compete against only the fuel costs of domestic production, since enough domestic capacity will always be available to meet domestic demand.

Second, a reserve margin calculated to be the capacity of the largest generating site in the region, or largest import source – "$\overline{\max G(z)}$" – must also be maintained during peak periods:

$$\sum_{i} \overline{PGinit(z,i)}(1-Decay)^{y} + \sum_{\tau=1}^{y} PG\exp(\tau,z,i)(1-Decay)^{y-\tau}$$

(4b) $$+ \sum_{zp}\left[PF(peak,y,zp,z)(1-\overline{Ploss(zp,z)}) - PF(peak,y,z,zp)\right]$$

$$\geq \left[\overline{D(peak,y,z)} - \overline{DSM(peak,y,z)}\right]\left[\overline{DLC(z)}\right] + \overline{\max G(z)} \quad \forall\ y,z,peak$$

2.7 The Country Autonomy Module

In addition to system reliability considerations, non-technical political, and economic factors may require that domestic production be maintained at some prescribed fraction of domestic demand, regardless of the economic advantages of importing cheap power. This will be the function of equation (5), which reflects the level of autonomy each country wishes to maintain, by specifying a country autonomy factor, $\overline{AF(z)} \geq 0$, which reflects each region's desire to be self-sufficient ($\overline{AF} \geq 1$), or willing to depend completely on imports during peak, if it is economic to do so ($\overline{AF} = 0$):

(5) $$\sum_{i} \overline{PGinit(i,z)}(1-Decay)^{y} + \sum_{\tau=1}^{y} PG\exp(\tau,i,z)(1-Decay)^{y-\tau}$$

$$\geq \overline{AF(z)}\left[\overline{D(t,y,z)}\,\overline{DLC(z)} - \overline{DSM(t,y,z)}\right] \quad \forall \quad t,y,z$$

2.8 The Objective Function Module

The objective function has two parts: the portion representing operating costs, and the portion representing new equipment purchase costs.

2.8.1. Operating Costs

If "$\overline{C(t, y, z, i)}$" is the operating fuel plus variable "O&M" cost per MWh of plant "i" in region "z" during time "t," in year "y" and "$\overline{UE\cos t(ty, z)}$" is the cost/unit of unserved energy, then the total operating cost is "$\overline{C(t, y, z, i)}$" times the output level per hour, "PG(t,y,z,i)", plus "$\overline{UE\cos t(ty, z)}$" times "UE(ty,z)". If the discount rate for present value purposes is "$\overline{disc}$," then the present value at "t=0" of all such costs in region "z" is just:

$$(6) \qquad \sum_{y=1}^{Yr} \sum_{t=1}^{T} \sum_{i=1}^{I} \frac{\overline{C(t, y, z, i)}PG(t, y, z, i)}{(1+\overline{disc})^{y-1}} + \frac{\overline{UE\cos t(t, y, z)}UE(t, y, z)}{(1+disc)^{y-1}}$$

(Note no discounting within a year)

2.8.2 New Equipment Costs

As was previously mentioned, all equipment purchase variables are integer variables -- equipment comes in a fixed MW unit size, "$\overline{expstep(z, i)}$" and a fixed cost, "$\overline{expcost(z, i)}$" per unit installed. The integer variable "Y(y,z,i)" = 0,1,2,... indicates the number of units installed at "i" in year "y". Thus "Y(y,z,i)*expstep(z,i)" is the MW capacity installed at "i" in "y" in region "z":

$$PGexp(y, z, i) = \overline{expstep(z, i)}Y(y, z, i)$$

The equipment costs associated with installing "PGexp(y,z,i)" MW in "y" enters the objective function in the following way.

Total investment in year "y" at "i" in "z" is "$\overline{expcost(z, i)}$Y(y,z,i)". To avoid the problem of no investments at the end of the planning horizon, the investment cost will first be levelized to a charge per period "y" by use of a capital recovery factor "$\overline{CRF(r, i)}$" where "r" is the cost of capital (which may or may not be identical with the discount rate) over the interval "y" and "i" the equipment type. The per period charge for equipment installed at "i" in "y", to be charged against all periods subsequent to, and including “y”, is then “$\overline{\mathrm{CRF}(r,i)}\,\overline{\mathrm{expcost}(z,i)}$Y(y,z,i)”.

Total charges in “y” should then be the sum of all such annualized charges arising from equipment purchases prior to, and including “y” - e.g.

$$\text{Total levelized charges in year y} = \sum_{\tau=1}^{y} \overline{\mathrm{CRF}(r,i)}\,\overline{\mathrm{expcost}(z,i)}\,Y(\tau,z,i)$$

The present value of these charges at “t=0” is;

$$\sum_{\tau=1}^{y} \frac{\overline{\mathrm{CRF}(r,i)}\,\overline{\mathrm{expcost}(z,i)}\,Y(\tau,z,i)}{(1+\overline{\mathrm{disc}})^{y-1}}$$

and the sum of all such charges over all years over all equipment, rather than just year “y”, is;

$$(7) \qquad \sum_{i=1}^{I} \sum_{y=1}^{Yr} \sum_{\tau=1}^{y} \frac{\overline{\mathrm{CRF}(r,i)}\,\overline{\mathrm{expcost}(z,i)}\,Y(\tau,z,i)}{(1+\overline{\mathrm{disc}})^{y-1}} \quad \forall z$$

Investment in transmission capacity is handled in a similar fashion by introducing “expcost(z,zp)” and “Y(y,z,zp)”, and remembering that costs from “z” to “zp” will be split equally with costs from “zp” to “z” -- e.g., “expcost(z,zp)” must be divided by 2:

$$(8) \qquad \sum_{z,zp} \sum_{y=1}^{Yr} \sum_{\tau=1}^{y} \left[\frac{\mathrm{CRF}(r,i)\,\overline{\mathrm{expcost}(z,zp)}\,Y(\tau,z,zp)}{2(1+\overline{\mathrm{disc}})^{y-1}} \right] \quad \forall z$$

This completes the description of the simplest version of the proposed SAPP long-run model. The summary of the equations and variable and parameter definitions follow.

2.9 Summary of the Model

2.9.1 The Demand/Supply Module

Let:

$\mathrm{PG}(t, y, z, i)$ = a continuous variable indicating the MW generated at plant "i" in "z" during "t" in "y"

$\mathrm{PF}(t, y, zp, z)$ = a continuous variable indicating MW power flows from "zp" to "z" in "t" in "y"

$\overline{\mathrm{Ploss}(zp, z)}$ = a parameter giving line loss from "zp" to "z", in percent

$\overline{\mathrm{D}(t, y, z)}$ = a parameter giving MW demand during "t" in "y" in "z"

$\overline{\mathrm{DLC}(z)}$ = one plus a parameter giving distribution loss within "z", in percent

$\overline{\mathrm{DSM}(t, y, z)}$ = a parameter giving, demand side management, DSM in "z" during "t" in "y", in MW

Then,

$$\text{s.t.} \quad (1) \quad \sum_{i} \mathrm{PG}(t, y, z, y) + \sum_{zp} \mathrm{PF}(t, y, zp, z)(1 - \overline{\mathrm{Ploss}(zp, z)}) - \sum_{zp} \mathrm{PF}(t, y, z, zp)$$
$$= \left[\overline{\mathrm{D}(peak, y, z)} - \overline{\mathrm{DSM}(peak, y, z)}\right]\left[\mathrm{DLC}(z)\right] \forall\ t, y, z$$

2.9.2 The Capacity Constraint Module

A) <u>All units</u>

Let:

$\mathrm{PG}(peaks,\ y, z, i)$ = MW power generated during a predetermined set of peak hours in year "y" at plant "i" in region "z", PG(offpeaks,y,z,i) similarly defined

$\mathrm{Y}(y, z, i)$ = an integer variable (0,1,2,3,...) indicating how many new units of fixed size are installed at plant "i" in "z" during year "y"

$\overline{\mathrm{PGinit}(z, i)}$ = a parameter giving the initial capacity of "i" in "z", in MW

$\overline{\mathrm{expstep}(z, i)}$ = a parameter indicating the fixed capacity increment per unit of "i", in MW

$\overline{\mathrm{FOR}(z, i)}$ = a parameter giving the forced outage rate of "i" in "z", in percent

$\overline{\mathrm{UFOR}(z, i)}$ = a parameter giving the unforced outage rate of "i" in "z", in percent

$\overline{\text{DECAY}}$ = a parameter guiding the percent decline in nameplate capacity per year for equipment

Then,

$$(2a)\ \text{PG}(\text{peaks}, y, z, i) \le \left[\overline{\text{PGinit}(z,i)}(1-\text{Decay})^{y} + \sum_{\tau=1}^{y} \overline{\text{expstep}(z,i)}\text{Y}(\tau,z,i)(1-\text{Decay})^{y-\tau}\right]$$

$$(1-\overline{\text{FOR}(z,i)})\ \forall\ \text{peaks}, y, z, i$$

$$(2b)\ \text{PG}(\text{offpeaks}, y, z, i) \le \Big[(\overline{\text{PGinit}(z,i)})$$

$$+\sum_{\tau=1}^{y} \overline{\text{exstep}(z,i)}\text{Y}(\tau,z,i)\ \Big](1-\overline{\text{FOR}(z,i)})(1-\overline{\text{UFOR}(z,i)})\ \forall\ \text{offpeaks}, y, z, i$$

B) <u>Additional Constraints on Hydro Only</u>

Then,

$$\sum_{\tau=1}^{T} \text{PG}(\tau, y, z, ih) \le \text{HROmwh}(z, ih)\ \text{fdrought}(y)$$

for run of river,

$$\sum_{\tau=1}^{T} \text{PG}(\tau, y, z, ih) \le \text{HDOmwh}(z, ih)\ \text{fdrought}(y)$$

for dams.

C) <u>Transmission</u>

Let:

$\text{Y}(y, z, zp)$ = an integer variable indicating how many increments of transmission capacity added in year "y"

$\overline{\text{PFinit}(z, zp)}$ = a parameter giving the initial transmission capacity in MW from "z" to "zp"

$\overline{\text{expstep}(z, zp)}$ = a parameter giving the fixed capacity increment/unit in MW of {z,zp}

$\overline{\text{FOR}(z, zp)}$ = a parameter giving the transmission forced outage rate on {z,zp}, in percent

Then,

$$(3)\quad PF(t,y,z,zp) \leq$$

$$\left(\overline{PFinit(z,zp)}(1-Decay)^{y} + \sum_{\tau=1}^{y} \overline{expstep(z,zp)}\,Y(\tau,z,zp)(1-Decay)^{y-\tau}\right)$$

$$\left(1-\overline{FOR(z,zp)}\right) \forall\ z,i,t,z,zp,y,\quad Y(\tau,z,zp) = Y(\tau,zp,z)$$

2.9.3 The Reliability Module

A) Reserve Margin

Let:

$\overline{RES(i)}$ = a parameter giving the required reserve margin for generation plant "i", in percent

$\overline{RESEXP(z)}$ = a parameter giving the required reserve margin for peak exports, in percent

$\overline{RESIMP(z)}$ = a parameter giving the required reserve margin for peak imports, in percent

$\overline{D(peak,y,z)}$ = a parameter giving single hour peak MW demand during "y" in "z"

$\overline{DSM(peak,y,z)}$ = a parameter giving single hour peak DSM in "z" during "y", in MW

Then,

$$(4a)\ \sum_{i} \frac{\overline{PGinit(z,i)(1-Decay)^{y}} + \sum_{\tau=1}^{y} \overline{\exp step(z,i)}\,Y(\tau,z,i)(1-Decay)^{y-\tau}}{1+\overline{RES(i)}}$$

$$+ \sum_{zp} \frac{PF(peak,y,zp,z)(1-\overline{Ploss(zp,z)})}{1+\overline{RESIMP(z)}} - \sum_{zp} \frac{PF(peak,y,z,zp)}{1+\overline{RESEXP(z)}}$$

$$\geq \left[\overline{D(peak,y,z)} - \overline{DSM(peak,y,z)}\right]\left[\overline{DLC(z)}\right] \forall\ y,z,peak$$

B) <u>Single Worst Contingency</u>

Let:

$\overline{\max G(z)}$ = a parameter giving the capacity of the largest operating unit in "z", in MW, or the maximum import capacity, whichever is greater.

Then,

$$(4b)\quad \sum_{i} \overline{PGinit(z,i)}(1-Decay)^{y} + \sum_{\tau=1}^{y} \overline{expstep(z,i)} Y(\tau,z,i)(1-Decay)^{y-\tau}$$

$$+ \sum_{zp} \left[PF(peak,y,zp,z)(1-\overline{Ploss(zp,z)}) - PF(peak,y,z,zp) \right]$$

$$\geq \left[\overline{D(peak,y,z)} - \overline{DSM(peak,y,z)} \right] \left[\overline{DLC(z)} \right] + \overline{\max G(z)} \quad \forall\, y,z,peak$$

2.10 The Country Autonomy Module

Let:

$\overline{AF(z)}$ = a self sufficiency parameter which reflects each countries willingness to depend on trade for satisfying peak demands ("AF(z)" > 1 means entirely self sufficient, "AF(z)" < 1 means some willingness to use trade to satisfy peak demands)

Then,

$$(5)\quad \sum_{i} \overline{PGinit(z,i)}(1-Decay)^{y} + \sum_{\tau=1}^{y} \overline{expstep(z,i)} Y(\tau,z,i)(1-Decay)^{y-\tau}$$

$$\geq \overline{AF(z)} \left[\overline{D(peak,y,z)} - \overline{DSM(t,y,z)} \right] \left[\overline{DLC(z)} \right] \quad \forall\, t,y,z$$

$$PG(t,y,z,i) \geq 0,\ Y(y,z,i) = 0,1,2,\ldots \qquad Y(y,z,zp) = 0,1,2,\ldots$$

2.11 The Objective Function Module

A) Operating Costs

Let:

$\overline{C(t,y,z,i)}$ = a parameter indicating the cost/MW (fuel plus variable "O&M") of operating plant "i" in region "z" during time "t" in year "y", in dollars ($)

$\overline{disc}$ = discount rate to be used in the present value calculation in the objective function, in percent

Yr = horizon length, in years

Then,

p-19; (6) $$\sum_{y=1}^{Yr}\sum_{t=1}^{T}\sum_{i=1}^{I}\frac{\overline{C(t,y,z,i)}PG(t,y,z,i)}{(1+\overline{disc})^{y-1}} \quad \forall z$$

B.) Unserved Energy Costs

Let:

"$\overline{UEcost(t,y,z)}$" be the cost/MW of unserved energy in hour "t", year "y", in country "z", and "UE(t,y,z)" be the MW of unserved energy, we have;

$$\sum_{y}\sum_{t}\frac{\overline{UEcost(t,y,z)}UE(t,y,z)}{(1+disc)^{y-1}}$$

C) New Equipment Costs

a) generation equipment

Let:

$\overline{expcost(z,i)}$ = a parameter giving the fixed expansion cost per increment of capacity, in dollars ($)

$\overline{CRF(r,i)}$ = a parameter giving the period capital recovery factor, in percent, as a function of the cost of capital, and equipment life, thru the equipment type

Then,

p-21; (7) $$\sum_{z} \sum_{i=1}^{I} \sum_{y=1}^{Yr} \sum_{\tau=1}^{y} \frac{\overline{CRF(r,i)}\,\overline{expcost(z,i)}\,Y(\tau,z,i)}{(1+\overline{disc})^{y-1}}$$

b) transmission capacity

Let:

$\overline{expcost(z,zp)}$ = a parameter giving the fixed cost per increment of transmission capacity, to be split 50/50 between capacity expansion from "zp" to "z" and "z" to "zp", in dollars ($)

Then,

p-21; (8) $$\sum_{z,zp} \sum_{y=1}^{Yr} \sum_{\tau=1}^{y} \left[\frac{CRF(r,i)\overline{expcost(z,zp)}\,Y(\tau,z,zp)}{2(1+\overline{disc})^{y-1}} \right]$$

CHAPTER 3
OPERATING INSTRUCTIONS

The instructions for operating the long-term model take the form of questions and answers. It is first necessary to recognize what topic your question comes under. There are seven topical areas. These are:

- (1) Computing requirements and setting parameters (multipliers, number of years in each time period, level of complexity etc).
- (2) Power supply from new and old thermal sites.
- (3) Power supply from new and old hydropower sites.
- (4) Transmission and trade.
- (5) Demand and reliability.
- (6) Finances.
- (7) Output files.

The minimum specification requirement for the personal computer, employed for best performance, with the long-term (LT) model is described below:-

PentiumII BX 100MHz motherboard,
PentiumII 350MHz processor,
512MB 100MHz RAM,
9.61GB UW SCSI hard drive,
NTwindows.

The commercial software that needs to be purchased and installed on the PC for the model to run is:

GAMS
CPLEX

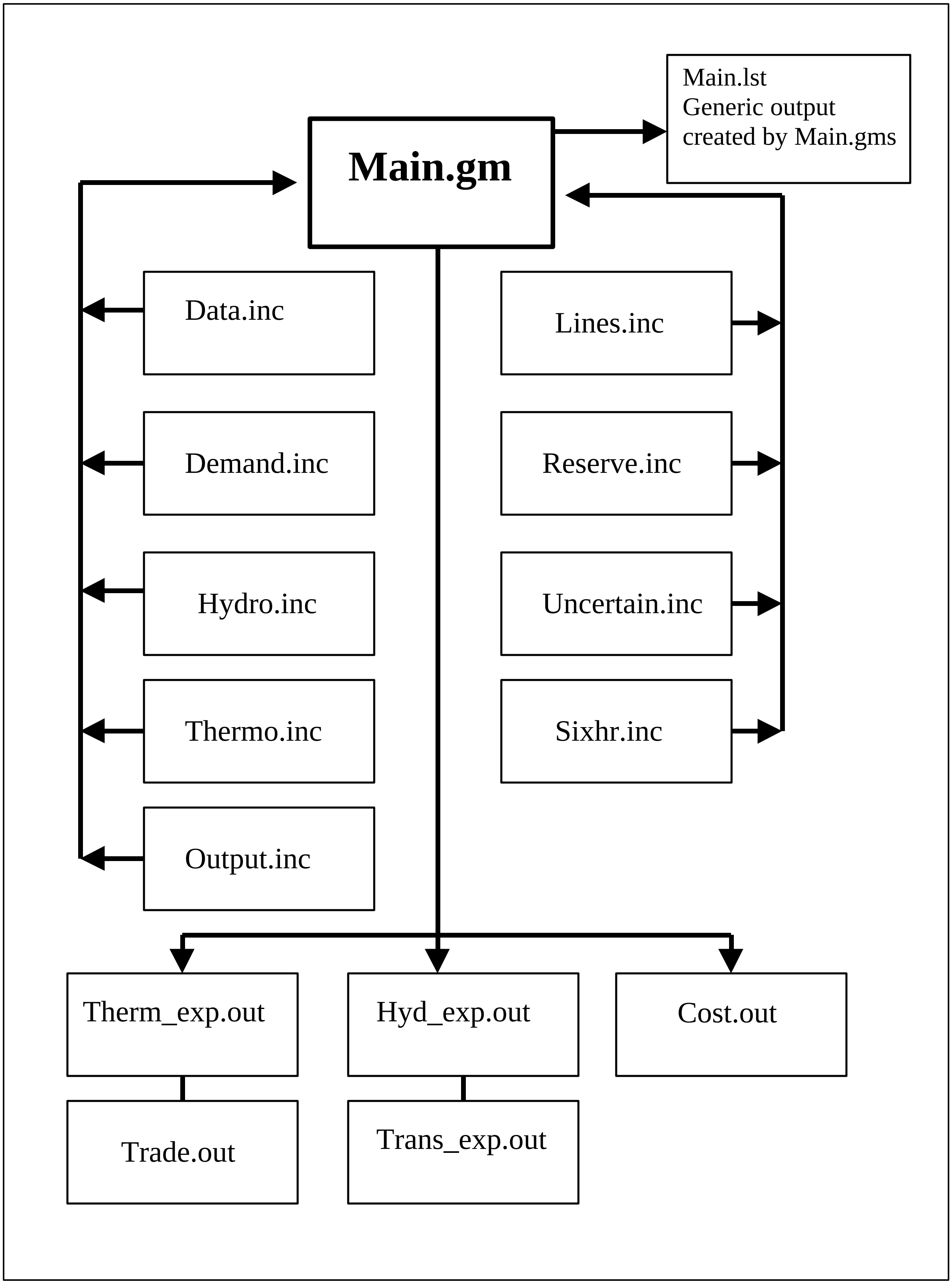
All users of the long-term (LT) model should consider the questions above in (1). The level of accuracy, is set by a modeling function, OPTION OPTCR, in the Main.gms file and by the number of discrete variables that are permitted with the new projects. The running time of the model is significantly affected by the expected level of accuracy.

The number of years in each time period determines how long the time horizon is to be. The value or length of each period can be set at either 1, 2, 3, 4 or 5 years.

There are a total of 5 periods. There is no expansion in the first period; only dispatch. This is because time must be provided for any construction to take place. Expansion is allowed though in the first year of the second period. The default setting for the length of each period is five years (n = 5). The default settings for the time horizons is therefore:

Period 1 commences at	year 2000
Period 2 commences at	year 2005
Period 3 commences at	year 2010
Period 4 commences at	year 2015
Period 5 commences at	year 2015

Figure 3.1 The Files that Comprise the Long-Term Model



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

(1) Main.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 capitol recovery factor on the thermal stations.

(3) Lines.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, capitol recovery of new lines, and cost of additional capacity on new lines.

(4) Demand.inc – contains data on demand of every country in MW for every hour of a specified day.

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

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

(7) Uncertain.inc – contains: data on uncertainties (i.e. expected rainfall)

(8) 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.

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

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

Output Files

(11) Main.lst – generic output file created by gams

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

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

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

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

(16) Cost.out – All costs involved with the expansion plans from running the model.

Operating Instructions

Operational questions and answers

It is an important part of modeling methodology to record the dates, in the text of the file, of when any values are changed or updated. It will be helpful to record ALL CHANGES made to the base model that is sent from Purdue's SUFG. When questions arise and the model is sent back to Purdue, from SAPP, then it will considerably speed up the response to any questions if all changes are noted and dated in adjacent text.

3.1 Computing Requirements and Setting of Parameters

(cost values, time horizons, levels of complexity etc)

3.1.1 *Question:* What are the minimum software installation requirements for running the LT model on a PC?

Answer: In order to run the SAPP-Purdue LT model the GAMS and CPLEX software will be installed on your PC. Details and cots for this software can be obtained from the GAMS Corporation;

Email: sales@ike.gams.com

Phone: USA 202-342-0180

Fax: USA 202-342-0181

3.1.2 *Question*: How can I improve the accuracy of the model?

Answer: File: Main.gms *Section Number:* 1

The tolerance or accuracy of the model is set at a very fine value. A default value of 0.000000002%. is used. This can be changed by entering the Main.gms file and changing the OPTION OPTCR value at the top of the file. A "1% accuracy" would be given the value 0.01 and 0.1% given 0.001 etc.

It is very important to remember that the greater the accuracy of the model then the length of time taken to run the model will also be much longer. Fast estimates can be obtained from the model by setting the accuracy at 3% or 4% (OPTION OPTCR = 0.03 or 0.04).

3.1.3 *Question:* What other ways are there for changing the accuracy and running times of the model?

Answer: *File:* Main.gms *Section:* 3

It is a major decision in the LT model on whether to allow a variable to be discrete (binary or integer) or of continuous type. Changes to their condition will all be made in the Main.gms file. Any or all variables can be chosen to be either continuous or discrete. The following variables are the most likely, however, to be changed if any:

Yh(ty,z,nh),

Ypf(ty,z,zp),

YCC(tya,z,ni),

YLC(tya,z,ni).

The effect of switching one or more of these variables between continuous and discrete has been investigated through several experiments and the model was initially run with all variables set to continuous. Great caution is advised in making these changes as dramatic increases in model running time may result. It is recommended to consult with SUFG staff (email clallen@ecn.purdue.edu) before changing the base model types.

When the variables Yh(ty,z,nh) in file main.gms, section 3, are set to be discrete, then the run time considerably increases. Switching Ypf(ty,z,zp) in the main.gms file, section 4, does increase the run time as expected but the increase in the run time is not as important a concern as with the possible advantages from this operation. As expected, switching Yh(ty,z,nh) and Ypf(ty,z,zp) together to discrete variables does increase the run time, but this increase is very small compared with increase observed when only Yh(ty,z,nh) is changed. Switching only YLC(tya,z,ni) in the main.gms file, section 6, increases the run time, and this increase is also expected and reasonable

3.1.4 *Question*: How do I run the model?

Answer: Type: "gams Main.gms".

3.1.5 *Question*: How many files are in the model and what are their names?

Answer: The input and output files of the LT model are shown in Figure 3.1 and a brief description of each follows this figure.

3.1.6 *Question:* How are the files in the model related to each other?

Answer: The files in the model are divided into 3 categories.

(1) GAMS (optimization software) files: Main.gms

(2) There are nine Input Data Files:

Thermo.inc	Data related to Thermal Power Plants
Hydro.inc	Data related to the Hydro Power Plants
Demand.inc	Data on national demand - hourly
Sixhr.inc	Data on national demand - 6 periods/day - 4 hourly
Lines.inc	Data on international tie lines
Reserve.inc,	Data related to Required Reserve Ratios
Data.inc	Data Related to Growth Rates and parameters
Uncertain.inc	Uncertainty data
Output.inc	Directions for creation of output files

(3) There are six Output files:

Therm_exp.out	Results on thermal expansion
Hyd_exp.out	Results on hydro expansion
Trans_exp.out	Results on the lines expansion
Trade.out	Results on trade quantities
Exp_Cost.out	Expansion costs output
Main.lst	The standard GAMS general output file

The Main.gms model contains all the optimization constraints in GAMS language. The Main.gms pulls information out of the nine data files. The file Main.lst is a generic output file created by GAMS when running the file Main.gms. The rest of the output files extract information from this main output file to produce more specific output files.

3.1.7 *Question:* How do I set the number of years, 1,2,3,4 or 5 that are in each time period?

Answer: File: Main.gms *Section Number:* 1

The model has the 5 time periods, and each contains a specific number of years (i.e. 1, 2, 3, 4 or 5). To set the number of years in each period go to your Main.gms file. In the middle of section 1 you will see

```
****************select # of years in each time period ********************
scalar n number of years in each time interval          /5/
```

Change the scalar value of “n” (default value 5) to the value you want.

3.1.8 *Question:* How do I set the number of hours in one day?

Answer: The default value is the 6 hour model (ie 6 x 4 hours). It is difficult to change this without considerable knowledge of GAMS. Changes have to be made in several files and it is recommended that advice is found before trying to change the default value.

For more information about this email: clallen@ecn.purdue.edu

3.1.9 *Question:* How do I change the number of days types in each year?

Answer: File: Main.gms *Section Number*: 2

Change the Mday(td) parameter in the Main.gms file. The default values are:

off-peak=52,
peak=52,
average=261

3.1.10 *Question:* How do I change the season factor?

Answer: There is no quick way to do this at present. The summer demand is set at 90% of the peak winter demand. This has been done manually for all the data involved.

3.1.11 *Question:* How do I change the autonomy factor?

Answer: File: Reserve.inc *Section Number:* 1

The AF(z,ty) table shows the default values for each country. When AF is equal to 1 then the country wishes to be totally self sufficient. When AF is equal to 0 then there is a total dependence on imports. Values of 0 to 1 can therefore be given to any one of the countries.

3.1.12 *Question:* Do I need to set the financial constraint before running the model?

Answer: File: Main.gms *Section Number:* 28

The default value for any period is a maximum of $5 billion and a minimum of $0.3 billion. If you wish to change the default values then change the RHS of the BUDGETmax and BUDGETmin equation.

Half way through Section 28 you will see:

=G= n * 0.3e9;

The 0.3 is the min value and can be changed to another value.

Similarly at the end of Section 28 you will see:

=L= n * 5e9

The 5 is the max value and can be changed to another value.

3.2 Power Supply from New and Old Thermal Sites

3.2.1 *Question:* How do I implement a MW extension increase to an existing thermal site?

Answer: File: Thermo.inc *Section Number:* 14 - old thermal (PGOmax) and new turbine (PGNTmax)

Section Number: 15 - for new small coal (PGNSCmax) and combined cycle (PGNCCmax)

Section Number: 16 - for new large coal (PGNLCmax)

Change the value that you wish to any of these variable but if, for example, you wish to add 300MW to an existing 800MW plant then do not put 1100MW but just the 300MW increase.

3.2.2 *Question:* How do I change the initial capacity to an existing thermal site.

Answer: File: Thermo.inc *Section Number:* 13

Go to Table PGOinit(z,i) and change value to the one required.

3.2.6 *Question:* How do I show an escalation of fuel costs for a country in a specific time period?

Answer: File: Thermo.inc *Section Number:* 9,10

The escalation of fuel cost is expressed as a percentage of the fuel cost and is set for the whole time horizon. It can not be changed for different time periods.
The escalation rates are shown for each type of generation. fpescNCC (combined cycle), fpescNSC (new small coal), and fpescNLC (new large coal). Go to the parameter and country required and change for the new value of escalation.

3.2.7 *Question:* Where can I change the cost of fuel in country z for year ty?

Answer: File: Thermo.inc *Section Number:* 7,8

The fuel prices for old thermal (fpPGO) and new gas turbine (fpNT) are listed in Section 7. The fuel prices for new combined cycle (fpNCC), new small coal (fpNSC) and new large coal (fpNLC) are listed in Section 8. Change values as required.

3.2.8 *Question:* Where do I look for the outputs of the model to find what new or extension thermal stations are proposed?

Figure 4.3b: New plant initial construction, with continuous expansion
Therm_exp.out

3.3 Power Supply from New and Old Hydropower Sites

3.3.1 *Question:* How do I add or delete a new hydropower generation project to/from the model?

Answer: File: Hydro.inc Section Number: 1,2,6,8

Tables HNninit, HNFcost, HNVcost, crfnh, FORnh are the ones which will need to be changed.

3.3.2 *Question:* How do I change the generating capacity of an existing hydropower generating station?

Answer: File: Hydro.inc *Section Number:* 4

The table Hoinit will be changed.

3.3.3 *Question:* How do I propose a MW extension increase to an existing hydropower site?

Answer: File: Hydro.inc *Section Number:* 4,5

The tables HOVmax, Hoexpsteo, HOVcost will be changed.

3.4 Transmission and Trade

3.4.1 *Question:* How do I add or delete a new transmission project to/from the model?

Answer: File: Lines.inc *Section Number:* 2,4,5,7

Five sets of tables need to be changed to achieve this. These are crf (Section 2), PFNFc (Section 4), PFNVc (Section 5), PFNloss (Section 5), and PFNinit (Section 7).

3.4.2 *Question:* How do I implement the fixed trade scenario?

Answer: File: Main.gms *Section Number:* 13

Go to the $ontext and $offtext commands, before and after :

++++++++++ fixed trade; 6 hour model +++++++++++++

Make these commands non functional by inserting an * before each of them. The fixed trade scenario is then activated.

3.4.3 *Question:* How do I change the levels of fixed import quantities from country zp to country z for year ty and vice versa z to zp?

Answer: File: Lines.inc *Section Number*: 6

The quantities are changed in Table Pffix.

3.4.4 *Question:* How do I change the DLC for each country – Domestic Loss Coefficient?

Answer: File: Data.inc *Section Number:* 5

Change the DLC value for any country.

3.4.5 *Question:* How do I change the maximum addition to an old and/or new transmission line?

Answer: File: Lines.inc *Section Number:* 1,3,4,5

Old line values can be changed with the values of PFOVc (Sections 1) and PFOVmax (Section 3).

New line values can be changed with the values of PFNVmax (Section 4) and PFNVc (Section 5).

3.4.6 *Question:* How do I change the transmission loss factor in old and new lines?

Answer: File: Lines.inc *Section Number:* 3,5

Old line loss factors are changed with PFOloss (Section 3).

New line loss factors are changed with PFNloss (Section 5).

4.6.1 *Question:* How do I change fixed contract trade to free trade?

Answer: File: Main.gms *Section Number:* 13

Be sure that the $ontext and $offtext commands are in operation in Section 13.

3.5 Demand and Reliability

3.5.1 *Question:* How do I change the yearly demand growth rate for country z?

Answer: File: Data.inc *Section Number:* 2,3,4

The demand growth rates for 1996 to 2020 are shown below in Table 3.1. The default values used in the model, for all time periods, are the medium value ones.

Table 3.1 Demand Growth Rates for 1996 to 2020

COUNTRY	LOW % p.a.	MEDIUM % p.a.	HIGH % p.a.
Angola	6.2%	7.9%	10.5%
Botswana	3.7%	4.3%	6.0%
Lesotho	3.4%	6.1%	8.2%
Malawi	2.1%	3.2%	6.2%
Mozambique	8.9%	10.9%	13.1%
Namibia	5.7%	7.2%	8.5%
South Africa	1.8%	3.6%	5.5%
Swaziland	2.5%	3.4%	4.5%
Tanzania	4.0%	6.0%	7.7%
Zambia	2.7%	4.4%	6.4%
Zimbabwe	2.9%	4.1%	5.9%
SADC tot/weighted av	2.0%	3.8%	5.7%
South Africa	1.8%	3.6%	5.5%
Rest of SADC	3.6%	5.0%	6.9%

3.5.2 *Question:* How do I change the forced outage rate for country z in year ty?

Answer: File: Reserve.inc *Section Number:* 2,3,4

Go to the appropriate table and section for each of the five types of stations:

Old stations	FORPGO	Section 2
New Turbine	FORNT	Section 2
New Combined Cycle	FORNCC	Section 3
New Small Coal	FORNSC	Section 4
New Large Coal	FORNLC	Section 5

3.5.3 *Question:* How do I change the unforced outage rate for country z in year ty?

Answer: File: Reserve.inc *Section Number:* 5,6,7,10

Go to the appropriate table and section for each of the five types of stations:

Old stations	UFORPGO	Section 10
New Turbine	UFORNT	Section 5
New Combined Cycle	UFORNCC	Section 6
New Small Coal	UFORNSC	Section 7
New Large Coal	UFORNLC	Section 7

3.5.4 *Question:* How do I change the load management capacity?

Answer: File: Reserve.inc *Section Number:* 12

The default values are set at zero by country and by hour.

3.5.5 *Question:* How do I change the reserve margin for thermal and hydropower stations and for transmission?

Answer: File: Reserve.inc *Section Number*: 12,13

Thermal stations	Section 12	Default values are set at 19%
Hydro stations	Section 13	Default values are set at 10%
Transmission	Section 13	Default values are set at 25%

3.6 Finances

3.6.1 *Question:* How do I change the capital cost of new thermal generation projects?

Answer: File: Thermo.inc *Section Number:* 1

New Combined Cycle Stations	PGNCCinit	Section 1
New Large Coal Stations	PGNLCinit	Section 1

There are no fixed capital costs for the NT and NSC because these are set as continuous variables.

3.6.2 *Question:* How do I change the capital cost of new transmission projects?

Answer: File: Lines.inc *Section Number:* 4

Change variable value for PFNFc.

3.6.3 *Question:* Where do I add the cost for an extension increase to an existing hydro site?

Answer: File: Hydro.inc *Section Number:* 5

Change variable value for HOVcost.

3.6.4 *Question:* How do I change the cost of unserved energy, UE, for country z in year ty?

Answer: File: Data.inc *Section Number:* 1

WARNING: It is important that a high cost exists for the unserved energy. The default value is $50,000/MW. Contact clallen@ecn.purdue.edu with questions on this topic.

3.6.5 *Question:* Where do I see the total cost of the expansion plan for the region?

Answer: File: Exp_Cost.out *Section Number.*

3.6.6 *Question:* .Where do I see the total cost of the expansion plan for country z?

Answer: File: Exp_Cost.out *Section Number*

3.6.7 *Question:* Where do I find the input operating and maintenance cost for thermal stations?

Answer: File: Thermo.inc *Section Number:* 17,18,19

Station Type	Section	Variable	Default value ($/MW)
NGT	17	OMT	8.6
NCC	18	OMCC	4.2
NSC	18	OMSC	6.7
NLC	19	OMLC	8.9
Old	19	OMO	8.9

3.6.8 *Question:* Where do I find the opportunity cost of water?

Answer: File: Hydro.inc *Section Number:* 1

This is a scalar value, “wcost”. The default value is $3.5/MW.

3.6.9 *Question:* Where do I find the heat rates?

Answer: File: Thermo.inc *Section Number:* 11,12,13

Station Type	Section	Variable	Default value ($/MW)
NGT	11	HRNT	11.25
NCC	12	HRNCC	7.49
NSC	13	HRNSC	9.8
NLC	12	HRNLC	9.8
Old	11	HRO	1.0

3.6.10 *Question:* Where do I find the fuel cost?

Answer: File: Thermo.inc *Section Number*: 7,8

Station Type	Section	Variable	Default value ($/MW)
GT	7	fpNT	4.0
CC	8	fpNCC	2.0
SC	8	fpNSC	0.4
LC	8	fpNLC	0.3
Old	7	fpO	1.3 - 77

3.6.11 *Question:* Where do I find the total transmission expansion cost for the region?

Answer: In the File:_Cost.out

3.6.12 *Question:* Where do I find the total cost of thermal expansion for the region?

Answer: In the File: Cost.out

3.6.13 *Question:* Where do I find the total cost of hydropower expansion for the region?

Answer: In the File: Cost.out

3.6.14 *Question:* Where do I find the total transmission expansion cost for country z?

Answer: In the File: Cost.out

3.6.15 *Question:* Where do I find the total cost of thermal expansion for country z?

Answer: In the File: Cost.out

3.6.16 *Question:* Where do I find the total cost of hydropower expansion for country z?

Answer: In the File:Cost.out

3.6.17 *Question:* Where do I find the total cost of the operations and maintenance for the region?

Answer: In the File: Cost.out

3.6.18 *Question:* Where do I find the total cost of the operations and maintenance for country z?

Answer: In the File: Cost.out

3.6.19 *Question:* Where do I change the cost of the operations and maintenance for a thermal plant?

Answer: File: Thermop.inc *Section Number*: 17,18,19

Station Type	Section	Variable	Default value ($/MWh)
NGT	17	OMT	8.6
NCC	18	OMCC	4.2
NSC	18	OMSC	6.7
NLC	19	OMLC	8.9
Old	19	OMO	8.9

3.6.20 *Question:* Where do I change the fixed capital cost of new thermal sites?

Answer: File: Thermo.inc *Section Number*: 1,2

Station Type	Section	Variable	Default value
CC	1	FGCC	$109 million
LC	2	FGLC	$581 million

3.6.21 *Question:* Where do I change the fixed capital cost of new hydropower plants?

Answer: File: Hydro.inc *Section Number:* 1

Change the values of the variable HNinit.

3.6.22 *Question:* Where do I change the fixed capital cost of new transmission lines?

Answer: File: Lines.inc *Section Number*: 4

Change the values of the variable PFNFc.

3.6.23 *Question:* Where do I change the capital cost of extensions to thermal sites?

Answer: File: Thermop.inc *Section Number* 3

Station Type	Section	Variable	Default value ($/MW)
NGT	3	NTexpcost	300000
NCC	3	NCCexpcost	412000
NSC	4	NSCexpcost	1433333
NLC	4	NLCexpcost	857000
Old	2	Oexpcost	1000000

3.6.24 *Question:* Where do I change the capital cost of extensions to existing hydropower sites?

Answer: File: Hydro.inc *Section Number:* 5

Change values to the variable HOVcost.

3.6.25 *Question:* Where do I change the capital cost of extensions to existing transmission lines?

Answer: File: Lines.inc *Section Number:* 1

Change the values of the variable PFOVc.

3.6.26 *Question:* Where do I change the values of the CRF for old and new thermal plants?

Answer: File: Thermo.inc *Section Number:* 16,17

Change values of the variables crfi, crfni.

3.6.27 *Question:* Where do I change the values of the CRF for old and new hydro plants?

Answer: File: Hydro.inc *Section Number:* 6,7

Change values of the variables crfih, crfnh.

3.6.28 *Question:* Where do I change the values of the CRF for new transmission lines?

Answer: File: Lines.inc *Section Number:* 2

Change values of the variable crf.

3.6.29 *Question:* Where can I change the escalation of fuel costs?

Answer: Thermo.inc *Section Number*: 9,10

Station Type	Section	Variable	Default value
NGT	9	fpescNT	1.01
NCC	10	fpescNCC	1.01
NSC	10	fpescNSC	1.01
NLC	10	fpescNLC	1.01
Old	9	fpescoO	1.01

3.6.30 *Question:* Where can I change the interest?

Answer:File: Data.inc *Section Number*: 1

Change the scalar *int.* The default value is 0.1

3.7 Output Files

3.7.1 *Question:* Where do I find the total cost (NPV) of the free trade optimization?

Answer: Running the free trade option the total cost is at the top of every output file.

3.7.2 *Question:* Where do I find the cost (NPV) to each country from the free trade optimization?

Answer: In the file: Cost.out

3.7.3 *Question:* Where do I find the total cost (NPV) of the fixed trade optimization?

Answer: Running the fixed trade option the total cost is at the top of every output file.

3.7.4 *Question:* Where do I find the cost (NPV) to each country from the no trade optimization?

Answer:File: Exp_cost.out *Section Number*

3.7.5 *Question:* Where do I see the list of chosen projects from the optimization?

Answer: The output files show the expansions for each country, the type of technology, and the MW quantities. A list of specific project names is to be coded in a new output file, yet to be finalized (January 1999).

3.7.6 *Question:* Where do I find the benefits of joint planning for my country?

Answer: First run the free trade option, taking the final cost, and then run the fixed trade option taking the final cost. The difference between the two final costs gives the benefits from joint planning.

3.7.7 *Question:* Where do I find the benefits of joint planning for SAPP?

Answer: First run the free trade option, taking the final cost, and then run the fixed trade option taking the final cost. The difference between the two final costs gives the benefits from joint planning.

3.7.8 *Question:* Where can I find the annual energy exports over time and the grand total for my country?

Answer: File: Trade.out *Section Number*

3.7.9 *Question:* Where can I find the annual energy imports over time and the grand total for my country?

*Answer:*In the File*:* Trade.out

3.8 Questions Related to The Formulation

3.8.1 *Question:* What are the pros/cons of choosing expansion to be continuous, rather than multiples of fixed plant sizes?

Answer: pro- quicker solution time con- round off error

3.8.2 *Question:* Can I select which variables are continuous, which are fixed multiples, or must I declare all to be one or the other?

Answer: You can select any or all to be either continuous or discreet

3.8.3 *Question:* What criteria should I use to decide if a capacity expansion variable should be continuous, or multiples of a fixed size?

Answer: Two factors: (a) the availability of units in many sizes (simple turbines) (b) the importance that the unit plays in the solution.

3.8.4 *Question:* Can I simply round off a continuous capacity variable to the size of the nearest available unit?

Answer: Yes, that is the suggested solution. If more accuracy is desired, run the model twice, once with the variable fixed at the rounded up value, once with the rounded down value.

3.8.5 Question: How are scale economics reflected in the model?

Answer: By associating a large fixed cost with the construction of the initial units of capacity e.g. initial fuel handling/water treatment/site preparation/transportation/sub-station costs for thermal, the dam for hydro, right of way purchase and tower construction for transmission.

3.8.6 *Question:* Does the model compete units with scale economics against units with constant returns to scale?

Answer: Yes, simple gas turbines and small coal plants are assumed to have constant returns to scale; they compete directly with combined cycle gas turbines and large coal plants; which ever is chosen is dependent on the yearly growth expected in a region - the larger the MW growth increment, the more likely the model will choose the units with scale economics, and lower costs. (Another advantage of SAPP wide capacity planning - fewer, bigger, cheaper (/KWh) units that are least cost if each country uses only it's own units to satisfy its own demand growth.

3.8.7 *Question:* Can I substitute my own thermal plants in place of those based on U.S. experience now in the model?

Answer: Yes, if the performance and cost of technology can be satisfactorily captured by the parameters used in the model to characterize U.S. technology initial capital cost, subsequent expansion cost, heat rate, capacity, forced/unforced outage rate, O&M cost, equipment lifetime, maximum size of expansion.

3.8.8 *Question:* Why are no capital costs for existing plant in the model?

Answer: These are considered sunk costs; the model considers only costs which can be avoided.

3.8.9 *Question:* Which types of costs - incremental, or average - should be used to populate the model?

Answer: Only incremental costs should be used.

3.8.10 *Question :* Is the model a discounted cash flow model?

Answer: Yes, with one exception. Equipment purchases where all the money is paid at the time of the purchase are treated as if the money is paid to the sources of capital in equal installments. The cash flows of plant and equipment financed over time by use of a capital recovery factor are correctly captured in the model.

3.8.11 *Question:* Can I alter the model to handle cases where all the money must be paid "up front"?

Answer: Yes, but this will require calculating a salvage value at the end of the planning horizon for the plants equipment, in order to allow the model to add capacity towards the end of the horizon.

3.8.12 *Question:* How does the model handle the cost of construction work in progress ("CWIP")?

Answer: It assumes that all dollars are spent in the year in which the plant comes on line. Thus, any carrying charges for work in progress should be added to the initial costs of the plant. Alternatively, the model could be modified to allow capital costs to begin to enter the objective function prior to initial operation, if the spending profile were specified. Some changes in the service code would be necessary, but none very complicated or time consuming.

3.8.13 *Question:* Must the capital cost of a new site include the cost of hook-up to the grid?
Answer: Yes, the assumption is that when the capital cost is incurred, all infrastructure is in place to allow the electricity to start satisfying demand.

3.8.14 *Question:* Are environmental consideration taken into account in the model:
Answer: Not at the present time. The source code could be easily modified to allow the model to keep track of the environmental impact (SOXNOX/particulate, etc.) of any SAPP plan, if data were made available by SAPP, or alternatively, typical U.S. plant data could be used.

3.8.15 *Question:* Do the capital costs of the default coal plants in the model take into account the environmental characteristics of the coal burned?
Answer: In an average way - capital costs include the cost of standard scrubbing equipment found on new coal fired plants installed in the U.S. which met U.S. current environmental standards for SOX/NOX/Particulate.

3.8.16 *Question:* How are the smaller thermal units now in place handled by the model?
Answer: The model ignores all units less than - MW, since they likely will never be used as a substitute for impacts, the key decision considered in the model.

3.8.17 *Question:* How can thermal units already committed to, but no on line, be entered into the model?
Answer: By treating their capacity as existing capacity in 2002 if the units are not expected to be in service by then. They can be treated as new equipment with the decision variable set at "build" in the period when the unit is expected to enter service.

3.8.18 *Question:* Why does the model not include commitment costs alone with dispatch costs?

Answer: Unit commitment includes the use of many conditional constraints of the if,then. form. These require many additional integer variables, and would drastically increase the running time with a less then commensurate increase in realism or accuracy.

3.8.19 *Question:* Can a more realistic assumption be made regarding the rate of decay than the constraint percentage assumption used in the model?

Answer: Yes, another formulation which allows arbitrary varying rates of decay over time is available, but not programmed into the model at the present.

3.8.20 *Question:* Who is responsible for financing an international transmission expansion?

Answer: Not specified in the model. Could split the cost into two countries for some cases.

3.8.21 *Question:* Should I have different assumptions for the CRFs for a large hydro project, such as the one in DRC? For example, if the project is developed by a consortium of RSA, DRC, and some IPPs from out side world, should the CRF in this case is the same as the one developed solely by DRC?

Answer: Not specified. Could be done by calculating different CRFs according to different assumptions.

3.8.22 *Question:* If the model is not run on a yearly basis (i.e., expansion for every year), what is the assumption for the capacities in the years not in the model? Are you assuming a constant capacity in the years?

Answer: Not clear at the time being.

3.8.23 *Question:* If the capacities in the years not modeled are not constant, then what are the capacities?

Answer: No answer yet.

3.8.24 *Question:* What are the capital costs associated with the variations mentioned in 22 and 23?

Answer: No answer yet.

3.8.25 *Question:* What are the production costs associated with the variations mentioned above?

Answer: Not simulated. A very rough estmation.

3.8.26 *Question:* Is it possible to improve your computation time to a one day limit with a convergence criterion of 0.1 %?

Answer: Model can make optimal runs (0.0%) within several hours and with 0.3% in less than half an hour.

3.8.27 *Question:* Is it possible to reduce the memory requirement?

Answer: Different algorithm will do but need more time and money to have it done.

Preferable a third year study.

3.8.28 *Question:* Is it possible to have a window based, user friendly interface such that we do not have to mess-up with the program?

Answer: Possible. But not this year.

3.8.29 *Question:* Is it possible to have window based interface to change data?

Answer: Possible if there is a third year study.

3.8.30 *Question:* It is desirable to have an algorithm to select the 6 day types, such that the total yearly energy is about right while retaining the peaks, especially for ESKOM.

Answer: *Possible and we need to do this.*

CHAPTER 4
THE FULL LONG-RUN MODEL

This chapter has four sections, each with its own appendix.

Section 1: The load balance, or supply/demand equations, which ensures that user specified demands are met for each of the hours in the six representative day types in the model-summer/winter peak, off-peak, and average days. (See Appendix 1A and 1B)

Section 2: The capacity constraints, which insure that each plant's generation does not exceed the properly derated installed capacity for the day types in the model. (See Appendix 2)

Section 3: The reliability constraints, which insure that a proper reserve margin is maintained between installed capacity and peak period demand in every period. (See Appendix 3)

Section 4: The objective function, which calculates the present value of all operating costs and all capital costs for new equipment over the planning horizon. (See Appendix 4)

4.1 The Demand/Supply Equations

4.1.1 The Demand for Electricity

The model is driven by the "typical hour/day/season/year" chronological demand approach taken by many of the latest commercial models, rather than the load duration curve methodology used in earlier approaches. The appendix to this chapter gives all the input files necessary to create the demand drivers for the model. Demands and supplies are for the utilities in SAPP, rather than for the SAPP countries. Thus, municipalities or others in the SAPP countries which generate and use their own electricity are not considered in calculating either the forecast demand, or the power available to meet such demands.

The model is set up to model demand in five representative periods in the future, starting in year 2000 to allow completion of all SAPP projects now underway.

The model allows the user to decide how many years each period will represent - every year (2000, 2001, 2002, 2003, 2004) or every other year (2000, 2002, 2004, 2006, 2008) every third year, etc., etc., by selecting the value for scalar “n” in the model. (See the appendix to this section.) The model automatically adjusts the yearly growth rates and the cost function to insure the model fully adjusts to the selection made by the user, allowing a range of planning horizons - 5, 10, 15, or 20 years

In all cases, no capacity expansion is allowed in the initial (2000) year; those construction projects SAPP indicated would be completed by that date are included as installed capacity. Thus, the first year’s optimization involves only dispatch of existing capacity against the first year’s demand.

TABLE 4.1: SADC & SOUTHERN AFRICA POWER POOL - GDP & CAPACITY GROWTH RATES - 1996-2020

1996-2020	Maximum Demand 1996 MW	GDP Growth (annual average rates)			Electricity to GDP Elasticity (underlying)	Electricity Intensive Projects MW	Demand Side M'ment by 2020 (H) MW	Maximum Demand (internal - 2020)			Maximum Demand growth rates 1996-2020			Comments
		LOW % p.a.	MEDIUM % p.a.	HIGH % p.a.				LOW MW	MEDIUM MW	HIGH MW	LOW % p.a.	MEDIUM % p.a.	HIGH % p.a.	
Angola	181	1.5%	3.0%	6.0%	1.26	1000	38	765	1111	2004	6.2%	7.9%	10.5%	Mining & mineral beneficiation
Botswana	222	3.6%	4.2%	5.9%	1.01	60	47	529	606	903	3.7%	4.3%	6.0%	Industry plants
Lesotho	76	3.5%	6.0%	8.0%	1.04		16	171	312	501	3.4%	6.1%	8.2%	
Malawi	164	2.0%	3.0%	5.5%	1.16		34	268	346	693	2.1%	3.2%	6.2%	
Mozambique	192	3.0%	5.0%	7.0%	1.36	2000	40	1481	2299	3662	8.9%	10.9%	13.1%	MOZAL, I&S (Maputo), Moatize Coal, other minerals
Namibia	321	3.5%	5.0%	6.0%	1.02	1000	67	1210	1704	2265	5.7%	7.2%	8.5%	Mining developments
South Africa	26382	2.0%	3.8%	5.5%	1.05	1500	7900	40244	62199	95108	1.8%	3.6%	5.5%	Mining & mineral beneficiation
Swaziland	140	2.6%	3.6%	4.6%	1.04		29	251	315	400	2.5%	3.4%	4.5%	
Tanzania	412	2.4%	4.0%	5.3%	1.30	500	86	1068	1672	2452	4.0%	6.0%	7.7%	Mining developments
Zambia	1028	2.4%	4.0%	5.8%	1.09	250	215	1928	2866	4511	2.7%	4.4%	6.4%	Mining back to capacity
Zimbabwe	1744	2.8%	4.0%	5.7%	1.04	400	366	3490	4626	6982	2.9%	4.1%	5.9%	Mining & mineral beneficiation
SADC tot/weighted av	30862	2.1%	3.8%	5.6%	1.06	6710	8839	51406	78055	119483	2.0%	3.8%	5.7%	
South Africa	26382	2.0%	3.8%	5.5%	1.05	1500	7900	40244	62199	95108	1.8%	3.6%	5.5%	
Rest of SADC	4480	2.7%	4.1%	5.8%	1.10	5210	939	11162	15856	24374	3.6%	5.0%	6.9%	
Scenario probabilities											0.40	0.45	0.15	

Compiled by: Peter B. Robinson, July 1998

Yearly demand growth rates which differ by scenario (hi, medium, low, growth), by time period, and by country (parameter “dgrowth1(z)”, to “dgrowth5(z)” in the appendix to this section) can be specified by the user. Table 4.1 (page 2) gives country growth rates for the planning horizon as estimated by Dr. Peter Robinson for the July 1998 Cape Town workshop. The medium growth rates in the next to last column are the default values now entered in the growth rate tables, but can be over-ridden by the user. The program automatically converts the yearly growth rates into the proper growth rates for the periods of varying length in the model, as indicated in the section “parameter (dgr(z,ty)” in the appendix.

Within each year – two seasons – summer and winter – are modeled. The summer period contains nine months (273 days), while the winter contains three months (91 days). Within each season, three days – a peak day, an off-peak day, and an average day – are modeled.

Within the summer season, there are 39 peak days, 39 off-peak days, and 195 average days. Within the winter season, there are 13 peak, 13 off-peak, and 65 average days.

The 24 hour individual country consumption patterns during the base year 2002 for each of the two seasons - summer and winter - and each of the three day types - peak, off-peak, and average - are entered by users in the tables “Base(ts,td,z)” titled: “base winter peak”, “base winter off-peak”, “base winter average”, “base summer peak”, “base summer off-peak”, “base summer average”.

These tables are found in the appendix, with default values obtained by;

- projecting the July 24, 1997 (winter peak) data for all countries used in the short term model to the base year 2000 by use of the current growth rates of electricity demand for each SAPP country provided by SAPP;
- creating the other five day types from projected winter peak consumption by use of day factors - off-peak = 0.7, peak = 1.0, average = 0.8 - and season factors - summer = 0.9 and winter = 1.0.

Users of the model can choose any of three options for modeling the hourly demand each day:

Option #1: (The Default Option) A weighted 6-hour version of the 24-hour data, containing one off-peak hour (hr9), three peak hours (hr19, hr20, hr21), and two average hours – one an average of eight such night hours, “avnt,” and one an average of 12 average day hours, “avdy.” The two average hours are calculated to insure that total energy use is the same for the six-hour version as the 24-hour version.

Option #2: 24-hour demand data for each country.

Option #3: A one-hour peak demand version (hr19 only) used for debugging purposes only.

In all cases, the base day type tables in the appendix are called; the choice of the one-hour, six-hour, or 24-hour version is dictated by the use of the “$ontext” and “$offtext” GAMS commands.

All this comes together in creating the demand driver for the model, parameter “Dyr(ty,ts,td,th,z)”, which is country “z”’s MW demand in year “ty” (“ty” = 2002, and then 2, 3, or 4 year periods as chosen by the user) in season “ts” (“ts” = winter, summer) in day “td” (“td” = peak, off-peak, average) in hour “th” (“th” = hr19 for the one-hour model; hr9, avnt, hr19, hr20, hr21, and avdy in the 6-hour model; hr1 to hr24 in the 24-hour model): Combining the yearly growth assumptions with the base year day type demand data, we have;

$$Dyr(ty,ts,td,th,z) = Base(ts,td,th,z)dgr(ty,z)$$

In GAMS notation (Main.gms file, section 2)

```
Parameter Dyr(ty,ts,td,th,z);
   Dyr(ty,ts,td,th,z)=july2400(ts,td,th,z) * dgr(z,ty)
```

Next, the impact on these demands of domestic distribution loss and demand-side management must be considered.

Table “DLC(z)” in the appendix – the domestic loss coefficient in the model – is applied to the demand value to allow for electricity loss within each SAPP region; it converts demand at the customer meter into demand at the generating station. Thus, it is important that demand measured at the customer meter be entered in the tables, not demand at the generation station.

The demand-side management (“DSM”) parameter – (“LM(th,z)” in the appendix to this chapter) – allows SAPP member specified “DSM” options to fractionally adjust up or down the load shapes of the representative days in the model, with user-specified costs of such programs entered into the objective function. It should be emphasized that the model in its current form does not compete “DSM” against normal supply side options to obtain the least cost mix of “DSM” and capacity expansion. It simply allows various “DSM” options with known costs and benefits to be entered into the model to see “off-line” if they are cost effective when compared to supply alternatives. It is planned to add “DSM” to the optimization formulation at a later date, as described in Appendix 2 to this section.

Table 4.2a Optional New SAPP Generating Capacity

(A Revision of Year 2 Interim Report Appendix V, - January 29, 1999)

Country	Powerstation	# of Units	Unit Size (MW)	Total Added MW)	Cost $ million	Type T/H/PS	Cost $/kW	HR Btu/ KWh	Fuel $/ MWh	O & M Cost $/MWh
	Optional Projects									
Angola	Cambambe (Ext.)	2	45	90		H				
Angola	Capanda II	2	130	260	300	H	1153			
Botswana	Moropule (Ext.)	2	120	240	420	T	1750			
DRC	Inga 3			3500	4900		1400**			
DRC	Grand Inga ST1			4750	9780	H	2059			
DRC	Grand Inga ST2			4750	6330	H	1332			
DRC	Grand Inga ST3			4750	6120	H	1288			
DRC	Grand Inga ST4			4750	6070	H	1278			
Lesotho	Muela	3	24	72	58	H	805			
Malawi	Kaphichira Phase1 *	2	32	64	—	H				
Malawi	Kaphichira Phase 2	2	32	64	24	H	375			
Malawi	Lower Fufu	2	45	90	119	H	1322			
Malawi	Mpatamanga	5(?)	63(?)	315	335	H	1063			
Malawi	Kholombidzo	2	35	70	330	H	4714			
Mozambique	Mepanda Uncua	5	400	2000	2800	H	1400***			
Mozambique	Cah. Bassa N. (Ext.)			1240	1054	H	850			
Namibia	Kudu (Gas)	1	750	750	650	T	866			
Namibia	Epupa	1(?)	360	360	408	H	1133			
South Africa	Komati A (Recomm).	5	5x90	450	125	T	277	12876	5.154	5.416
South Africa	Grootvlei (Recomm).	6	5x190+1x 180	1130	123	T	109	12186	7.673	4.236
South Africa	Komati B (Recomm).	4	4x110	440	238	T	542	12876	6.026	0.68
South Africa	Camden (Recomm).	8	190	1520	164	T	108	12186	5.855	4.122
South Africa	PB Reactor	10	100	1000	844	T	844	7583	3.4	0.2
South Africa	Lekwe	6	659	3950	4056	T	1027	9890	4.119	0.6
South Africa	Pumped Storage A	3	333	999	373	PS	374			
South Africa	Pumped Storage B	3	333	999	377	PS	378			
South Africa	Pumped Storage C	3	333	999	379	PS	380			
South Africa	High head UGPS	2	500	1000	237	PS	237			
South Africa	Gas Turbine	4	250	1000	324	T	324	9478	58.66	0.646
Tanzania	Ubungo (Gas)	1	40	40	24	T	600	9045	25.6	3.405
Tanzania	Tegeta (Gas)	10	10	100	90	T	900	11055	140.0	
Tanzania	Kihansi	3	60	180	270	H	1500			
Tanzania	Rumakali	3	74	222	439	H	1977			
Tanzania	Ruhudji	4	89.5	358	515	H	1438			
Zambia	Itezhi-Tezhi	2	40	80	74	H	927			
Zambia	Kafue Lower	4	150	600	450	H	750			
Zambia	Batoka North	4	200	800	898	H	1122			
Zambia	Kariba North (Ext.)	2	150	300	223	H	743			
Zimbabwe	Hwange Upgrade	1	84	84	130	T	1547			
Zimbabwe	Hwange 7 & 8	2	300	600	554	T	923	9574	3.427	
Zimbabwe	Gokwe North	4	300	1200	960	T	800	9248	3.023	
Zimbabwe	Batoka South	4	200	800	898	H	1122			
Zimbabwe	Kariba South (Ext.)	2	150	300	200	H	667			
	Commited Projects									
South Africa	Majuba*	6	3x612, 3x667	3837	—	T		10340	5.734	0.495
South Africa	Arnot 3-6 Recomm.*	4	4x330	1320	—	T		10185	3.223	0.718

*Commissioned by 2000, ** Estimated, ***Estimated and assumed given 664 did not include dam

Table 4.2b SAPP Thermal Generation Data for Existing Plants

Country & Station Name	PGmax (MW)	Country & Station Name	PGmax (MW)
Angola	113		
Botswana	118	RSA	
		Arnot	1320
Mozambique		Duvha	3450
Beira	12	Hendrina	1900
Maputo	62	Kendal	3840
Namibia		Kriel	2700
Vaneck	108	Lethabo	3558
Paratus	24	Majuba	1836
Zimbabwe		Matimba	3690
Hwange	956	Matla	3450
Munyati	80	Tutuka	3510
Harare	70	Koeberg *	1840
Bulawayo	120		
Swaziland	9	(* Nuclear)	

Table 4.2c SAPP Hydropower Generation Data for Existing Plants

Country & Station Name	Hmax (MW)	Country & Station Name	Hmax (MW)
Angola	121	Malawi	
	56	Knula	214
	37	Tedzani	64
	37	Tedzani	64
	37		
DRC		RSA	
Inga	1775	Gariep	320
Nseki	248	Vanderkloof	220
Nzilo	108	Palmiet #	400
Mwadingusha	68	Drakensbur#	1000
Koni	42		
Mozambique		Zimbabwe	
HCB	2075	KaribaSouth	666
Chic-Cor-Mav	81	Zambia	
Namibia		KaribaNorth	600
Ruacana	240	Kafue	900
Swaziland	40	Victoria	100
		(# Pumped)	

Finally, combining the yearly growth assumptions with the "DLC" and "DSM" data allows the specification of the right-hand side of the load balance equation, which specifies: for each hour in each day in each season in each year, the demand at the generating station that must be met inclusive of the effect of distribution line loss and "DSM" programs is then;

$$[\mathrm{Dyr}(ty, ts, td, th, z) - \mathrm{DSM}(th, z)][\mathrm{DLC}(z)]$$

4.1.2 The Supply Side

The demand in a given region can be met from a variety of energy sources: (a) existing thermal sites, (b) new thermal sites, (c) existing hydro sites, (d) new hydro sites, (e) net imports (imports less exports), (f) paying an unserved energy cost, (g) pumped storage.

Within each region, generating sites are identified which contain generating plants. For purposes of dispatch, all plants at a site are collectively dispatched. Generation variables, in MW, for the sites are:

PG(ty,ts,td,th,z,i) = generation from existing thermal site "i"

PGNT(ty,ts,td,th,z,ni) = generation from new gas turbines at site "ni"

PGNSC(ty,ts,td,th,z,ni) = generation from new small coal plants at site "ni"

PGNCC(ty,ts,td,th,z,ni) = generation from new combined cycle plants at site "ni"

PGNLC(ty,ts,td,th,z,ni) = generation from new large coal plants at site "ni"

H(ty,ts,td,th,z,ih) = generation from existing hydro site "ih"

Hnew(ty,ts,td,th,z,nh) = generation from new hydro site "nh"

PGPSO(ty,ts,td,th,z) - PUPSO(ty,ts,td,th,z) = net generation from old pumped hydro sites ("PGPSO" is generation supply, "PUPSO" is pump demand)

PGPSN(ty,ts,td,th,z,phn) - PUPSN(ty,ts,td,th,z,phn) = net generation from new pumped hydro sites ("PGPSN" is generation supply, "PUPSN" is pump demand)

Default value characteristics of new and old plants are based on data furnished by SAPP members, as well as data representative of the latest U.S. plants, as described below.

(a) Existing Thermal Sites

Tables 4.2a, b, c plus Table "PGOinit(z,i)", in the appendix to section 2 (The Capacity Constraint Module), lists the current MW capacities of the existing thermal sites in the model (including Nuclear, Koeberg, SSA) -- in addition to the set developed for the short-run model, (see the first year report for details), committed projects listed in Table 4.2 are also included. NSA has 12 sites (10 existing, 2 committed), Zimbabwe 4 sites, Namibia and Mozambique 2, and Angola, Botswana, Lesotho, Malawi, Swaziland, Tanzania, and Zambia have single sites, all coal fired. In addition, South Africa has one nuclear plant. The rows in Table "PGOinit(z,i)" are the locations listed in order of the "z" index assigned - e.g., Ang (Angola) is z=1, Bot (Botswana) is z=2, etc., Zimbabwe is z=14. (Note Mozambique and RSA are divided into two regions -north and south -to recognize the reality of the split supply situation in Mozambique, and the split demand situation in RSA). The site index "i" follows the column index "stat i".

Power generation in year "ty", season "ts", day type "td", hour "th", at old site "i" in country "z" is given by the continuous non-negative variable "PG(ty,ts,td,th,z,i)". Thus "PG(1,1,1,1,1,1)" is the MW contribution of Angola ("z"=1) site 1 (stat 1) during year 1 (2002) in season 1 (winter) in day type 1 (off-peak) during hour 1 (hour 1 for the 24 hour model, hour 9 for the 6 hour version).

(b) New Thermal Sites

Table 4.2 lists the characteristics of new or recommissioned thermal plants under consideration by SAPP. South Africa is considering 7 new thermal plants, including one new nuclear plant, Zimbabwe 3, Tanzania 2, and Botswana, Mozambique, and Namibia one each. In addition to utilizing the capacity of the existing coal fired sites described above and these new plants, the model allows development and construction of four types of new fossil fuel sites in selected countries where the fuel is available. A complete description of the four options will be given in the capacity expansion section later in the report, dealing with the values of "PGNinit(z,ni)".

- a small variable capacity simple cycle gas combustion turbine, available in all countries. Power generation in MW from such sites is given by the continuous variable "PGNT(ty,ts,td,th,z,ni)" in the model

- a small fixed capacity sub-critical coal plant, in RSA, Botswana, Zimbabwe, and Tanzania. Power generation levels are given by “PGSC(ty,ts,td,th,z,ni)”.
- a variable capacity combined cycle combustion turbine in those countries where natural gas could be available - Namibia, RSA, Mozambique, Tanzania, and Angola. Power generation from such sites is given by “PGNCC(ty,ts,td,th,z,ni)”
- a large variable capacity pulverized coal site, available only in RSA Power generation levels are given by “PGNLC(ty,ts,td,th,z,ni)”

The nominal values of these four plants’ technical and economic data in the model are taken from a recent survey of typical plants constructed world-wide. Users can override the nominal data, and enter the specifics of fossil fuel projects into the tables described in the capacity expansion section later in the report.

(c) Existing Hydro Sites

Table 4.2, plus Table “HOinit(z,ih)” - “z” the row (country) index, “ih” the column (site) index - in the appendix to section 2 (The Capacity Constraint Module), lists the current MW capacities of the existing hydro sites in the model. Angola, Tanzania, and DRC have 5 sites each, SWZ, and ZAM 3 each, MWI, NMZ, NSA, and SSA have 2 sites, and the rest of the countries in the table have one each. A complete description of the sites will be given later in the report.

MW output from the existing sites is given by the variable “H(ty,ts,td,th,z,ih)”.

(d) New Hydro Sites

Table 4.2, plus Table “HNinit(z,nh)” - again “z” the row (country) index, “nh” the column (new site) index - in the appendix to section 2 lists the hydro sites under consideration by SAPP members. MWI has 4 sites, TAZ and ZAM 3, ZIM 2, and ANG, LES, NMZ, NAM, and DRC one each. The options, as expected, are dominated by the expansions of DRC’s Grand Inga hydro site, which accounts for over two-thirds of planned hydro capacity. Total expansion plans involve the possible construction of almost 22,000 MW of new capacity, based on the 1995 SAPP official list of capacity expansion projects, contained in Table 4.2.

MW output from the new sites is given by the variable “Hnew(ty,ts,td,th,z,nh)”.

(e) Net Imports

Figures 2.1 and 2.2 in Chapter two, and Tables "PFOinit(z,zp)" and "PFNinit(z,zp)" the appendix to section 2 list the initial MW capacities of the existing and proposed lines respectively linking the 14 regions which make up SAPP in the model. The matrices are symmetric, so that power flow capacity from country A to B is the same as B to A, with the exception of DC lines.

Transmission losses on the lines are given in tables "PFOloss(z,zp)" for existing lines, and "PFNloss(z,zp)" for new lines in the appendix to this section.

MW power flows from region "z" to "zp" on old lines are given by the variables "PF(ty,ts,td,th,z,zp)" while flows on the new lines are given by the variables "PFnew(ty,ts,td,th,z,zp)". Using this notation, and accounting for line losses reducing the amount of power arriving at region "z", net imports for region "z" in a given hour would be;

$$\sum_{zp}\left[\overbrace{\mathrm{PF}(ty,ts,td,th,zp,z)(1-\mathrm{PFOloss}(zp,z))}^{\text{imports arriving on old lines}}-\overbrace{\mathrm{PF}(ty,ts,td,th,z,zp)}^{\text{exports sent on old lines}}\right]$$

$$+\sum_{zp}\left[\overbrace{\mathrm{PFnew}(ty,ts,td,th,zp,z)(1-\mathrm{PFNloss}(zp,z))}^{\text{imports arriving on new lines}}-\overbrace{\mathrm{PFnew}(ty,ts,td,th,z,zp)}^{\text{exports sent on new lines}}\right]$$

(f) Unserved Energy

Each region can choose not to meet demand by allowing unserved energy to enter the supply side of the demand/supply balance equation. The variable "UE(ty,ts,td,th,z)" gives the MW value of the amount. The scalar "UEcost" in the appendix to section 4 sets the cost/MWh of unserved energy. The nominal value is $5000, but it can be set at whatever value users want to adopt.

(g) Pumped Storage

At least two SAPP members (RSA and Tanzania) either have, or are planning to add, pumped storage as a means of peak-shaving/valley filling their 24 hour demand profiles. Table 4.2 contains data on the four known pumped storage projects planned by RSA. Pump storage uses electricity off-peak to pump water up to reservoirs, which are then discharged during peak periods.

The hourly (MW) amount of on-peak generating at the two existing pump storage sites in RSA will be indicated by the non-negative variable “PGPSO(ty,ts,td,th,z)”, while the hourly MW amount of off-peak pumping will be indicated by the non-negative variable “PUPSO(ty,ts,td,th,z)”. The power available for generation is less than the power used to pump because of pump storage system loss, given by the parameter “PSOloss”. Pumped storage facilities are assumed to operate on a 24 hour cycle - e.g. what is pumped up in a night must come down in the same day. Thus, the sum over all hours in a day of “PGPSO(·)” cannot exceed the sum overall hours of “PUPSO”, less loss;

$$\sum_{th} \mathrm{PGPSO}(ty, ts, td, th, z) \leq \sum_{th} \mathrm{PUPSO}(ty, ts, td, th, z)(1 - \mathrm{PSOloss})$$

In GAMS format, equation “oldpumped” is; (Main.gms file, section 25)

```
Equation Oldpumped;
Oldpumped(ty,ts,td,z) $PGPSOinit(z) ..
sum(th, Mtod(th) * PGPSO(ty,ts,td,th,z)) =L=
sum(th, Mtod(th) * PUPSO(ty,ts,td,th,z))*(1-PSOloss);
```

The GAMS equation indicates this is always an equality at an optimum solution, since it was decided not to include the possibility of longer term storage in the model.

The default value of “PSOloss” is set at 0.3 in the model.

The model enters pumped storage into the load balance equation on the supply side; hence “PGPSO(·)” enters with a positive sign, while “PUPSO(·)” enters with a negative sign; e.g.

Generation plus net imports +PGPSO(·) - PUPSO(·) = Demand

Pumped storage from new sites (indexed “phn”) enters into the model in a similar fashion, except the variables are “PGPSN(·)” and “PUPSN(·)”.

In GAMS format, equation “Newpumped” is; (Main.gms file, section 25)

```
Equation Newpumped;
Newpumped(ty,ts,td,z,phn) $PHNinit(z,phn) ..
sum(th, Mtod(th) * PGPSN(ty,ts,td,th,z,phn)) =L=
sum(th, Mtod(th) * PUPSN(ty,ts,td,th,z,phn) * (1-PSNloss(phn)));
```

4.1.3 The Full System Load Balance Equation

The load balance equation - “Equation Demand” in the model - requires that for all time periods for each country “z”, the sum of MW generation from:

- existing thermal sites - “PG(·)”
- new thermal sites - “PGNT(·)”, “PGNCC(·)”, “PGNSC(·)”, “PGNLC(·)”
- net imports over existing transmission lines - “PF(·,)(1-PFOloss(zp,z)” - “PF(·,z,zp)”
- net imports over new transmission lines -

  “PFnew(·,zp,z)(1-PFNloss(zp,z))” - “PFnew(·,z,zp)”
- existing hydro sites - “H(·)”
- new hydro sites - “Hnew(·)”
- old pumped storage - “PGPSO(·) - PUPSO(·)”
- new pumped storage - “PGPSN(·) - PUPSN(·)”

plus unserved energy

- “UE(·)”

must be greater than or equal to

- Demand - “Dyr(·)”
- less DSM - “LM(·)”
- times domestic loss - “DLC(z)”.

all this is entered into the model using GAMS notation as equation “Demand”; (Main.gms file, section 26)

```
EQUATION Demand;
Demand(ty,ts,td,th,z)..
  sum(i$(PGOinit(z,i) GT 1), PG(ty,ts,td,th,z,i))
+ sum(ni$(fpNT(z,ni) GT 0),  PGNT(ty,ts,td,th,z,ni))
+ sum(ni$(fpNCC(z,ni) GT 0), PGNCC(ty,ts,td,th,z,ni))
+ sum(ni$(fpNSC(z,ni) GT 0), PGNSC(ty,ts,td,th,z,ni))
+ sum(ni$(fpNLC(z,ni) GT 0), PGNLC(ty,ts,td,th,z,ni))
+ sum(zp$(PFOinit(zp,z) GT 9), PF(ty,ts,td,th,zp,z)*(1-PFOloss(zp,z))
                    - PF(ty,ts,td,th,z,zp))
+ sum(zp$(PFNinit(zp,z) GT 9), PFnew(ty,ts,td,th,zp,z)*(1-PFNloss(zp,z))
                    - PFnew(ty,ts,td,th,z,zp))
+ sum(ih, H(ty,ts,td,th,z,ih))
+ sum(nh, Hnew(ty,ts,td,th,z,nh))
+ UE(ty,ts,td,th,z)

+ PGPSO(ty,ts,td,th,z) - PUPSO(ty,ts,td,th,z)
+ sum(phn$PHNinit(z,phn),PGPSN(ty,ts,td,th,z,phn))
- sum(phn$PHNinit(z,phn),PUPSN(ty,ts,td,th,z,phn))

=G= DLC(z) * (Dyr(ty,ts,td,th,z) - LM(z,th));
```

(Note: the sum is over the only those new units which are actually in existence - e.g. those plants with positive initial capacity ("PGOinit" > 0) or those with positive fuel prices ("fp" > 0))

4.2 The Capacity Constraint Module

This section will be organized by site type, considering the capacity constraints in sequence of (a) old thermal sites, (b) old hydro sites, (c) new thermal sites, (d) new hydro sites, (e) old transmission lines, (f) new transmission lines, and (g) pumped storage.

In all cases, the model will allow no additions to capacity in 2000, the initial year of the horizon; those the SAPP delegates indicated were under way at the July 1998 workshop will be treated as capacity already installed. These projected initial capacities as of 2000 are included in the following tables:

- Thermal: Table "PGOinit(z,i)", totaling 33,100 MW
- Hydro: Table "HOinit(z,ih)", totaling 8380 MW
- Transmission: Table "PFOinit(z,zp)", totaling 14,430 MW
- Pumped Storage: 1400 MW

These capacities are based on installed capacity by plant name, taken from the earlier short run model, and committed new capacity, by plant name, given in Table 4.2, in section 1. Thus, only the optimal dispatch problem is solved in 2000, capacities being fixed: this means the year 2000 can be run in isolation from the rest of the program, since no decision in 2000 affects subsequent years.

When calculating the available capacity in a time period, the yearly nameplate capacity must be derated, by the expected forced and unforced outage rates. Since forced outages by their nature, can occur anytime, peak or off-peak, the yearly nameplate capacity must be derated by the expected forced outage rate for all operating periods, peak or off-peak. On the other hand, the timing of unforced, or planned outages for preventive maintenance can be chosen by the utility. Since generating capacity is more valuable during periods of peak demand than during off-peak periods, unforced outages are scheduled during off-peak periods. However, unforced outage rates are given in terms of annual percentage. The off-peak unforced outage rate is slightly larger than the annual rate, the peak unforced outage rate is zero, and the weighted average of the two rates equals the annual rate.

The thermal capacity constraints enter the model by day type. Hydro and transmission capacity will be derated only by forced outage rates, as will be explained below.

In addition, users can specify limits on new construction in the early years to insure sufficient construction time is available to complete the installations.

Since the model is a long-term year model, the likelihood that existing plants will deteriorate due to old age, and be unable to generate their initial capacities must be taken into account.

The model does this by introducing a user specified decay parameter "Decay(i)", a function of the technology type, giving the yearly percent reduction in generating capability, which applies to each site in each country, which is introduced into a generic capacity constraint in the following way.

A generic capacity constraint requires that generation in year "ty", "PG(ty,ts,td,th,z,i)", respect the available installed capacity in year "ty", equal to the sum of the initial capacity - adjusted for decay - plus the capacity added up to and including "ty" - again, adjusted for decay, properly derated for peak and off-peak periods;

$$
\begin{aligned}
PG(ty, ts, td, th, z, i) \le \Big[&(\text{Initial capacity})(\text{decay factor}) \\
&+ \sum_{\tau=1}^{ty} (\text{capacity added in } \tau)(\text{decay factor for capacity added in } \tau)\Big] \text{derate for day type}
\end{aligned}
$$

Assuming decay takes place at a constant percent per period "ty", the right hand side of the expression would be:

$$\Big[(\text{Inital Capacity})(1-\text{Decay})^{\text{ty}} \\ + \sum_{\tau=1}^{\text{ty}}(\text{Capacity added in }\tau)(1-\text{Decay})^{\text{ty}-\tau}\Big]\text{derate for day type}$$

For example: if "ty" = 3, the expression would be

$$\Big[(\text{Initial Capacity})(1-\text{Decay})^{3} + (\text{Capacity adde in 3})(1-\text{Decay})^{2} \\ + (\text{Capacity added in 2})(1-\text{Decay})^{1} + (\text{Capacity added in 3})(1-\text{Decay})^{0}\Big]\text{derate}$$

4.2.1 Old Thermal Sites

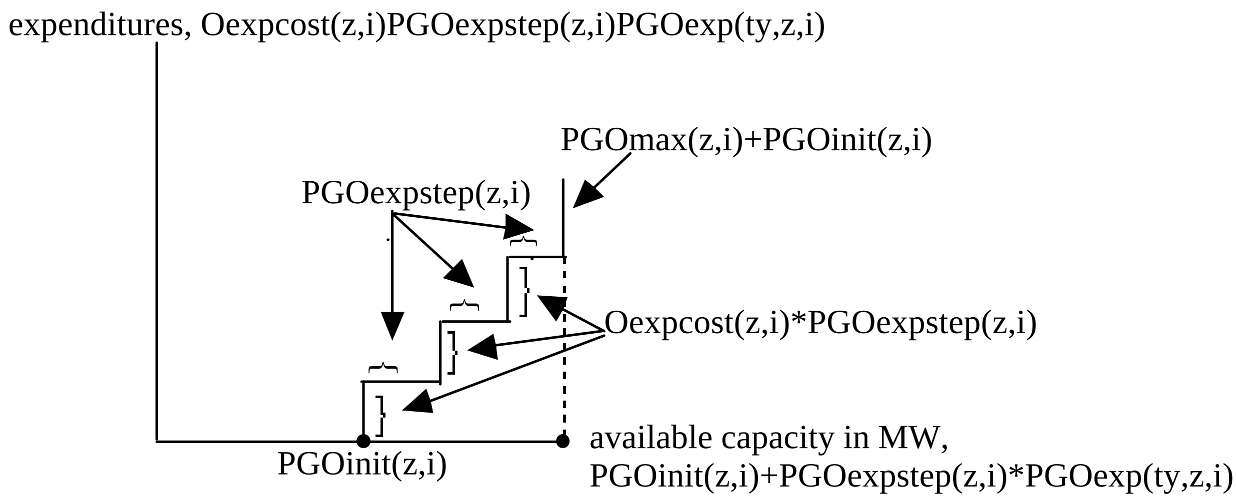
During all times within a given year "ty", the generation levels given by the variables "PG(ty,ts,td,th,z,i)" must respect the properly derated site capacity available in that year. Initial MW capacities for the sites are given in Table "PGOinit(z,i)" in the appendix to this section. The value of the decision variable "PGOexp(ty,z,i)" determines the amount of new MW capacity installed at site "i" in year "ty".

The user can select two options for modeling capacity expansion at existing sites - treating "PGOexp(ty,z,i)" as a continuous variable, or as an integer variable which allows only fixed multiples of a given size plant.

Figures 4.1a and 4.1b show the two possible ways of modeling capacity expansion at an already developed site. Both represent the initial capacity by the parameter "PGOinit(z,i)", and both have upper bounds on the total expansion possible at a site "PGOmax(z,i)" (tabled in the appendix to this section). They differ in the way the expansion is handled.

Figure 4.1a plots available capacity at site "i" as a function of the dollars expended on new capacity, if it is assumed that additional capacity is available in multiples of fixed plant sizes, indicated in Figure 4.1a as the step width, "PGOexpstep(z,i)", tabled in the appendix to this section.

FIGURE 4.1a: Expansion as fixed multiples of a given size, e.g., “PGOexp(ty,z,i)” = 0,1,2,3



The cost of a single expansion - the step height - is given by the product of the parameter “Oexpcost(z,i)” -which gives the cost/MW - times “PGOexpstep(z,i)”, the step width, in MW. If the integer decision variable “PGOexp(ty,z,i)” is defined as the number of units of size “PGOexpstep(z,i)” (the step width) installed in year “ty”, then it must be true that capacity utilization in “ty” at site “i” cannot exceed the initial capacity plus the cumulative expansion up to and including that made in year “ty” e.g.;

$$\mathrm{PG}(\mathrm{ty},\mathrm{ts},\mathrm{td},\mathrm{th},\mathrm{z},\mathrm{i}) \leq$$

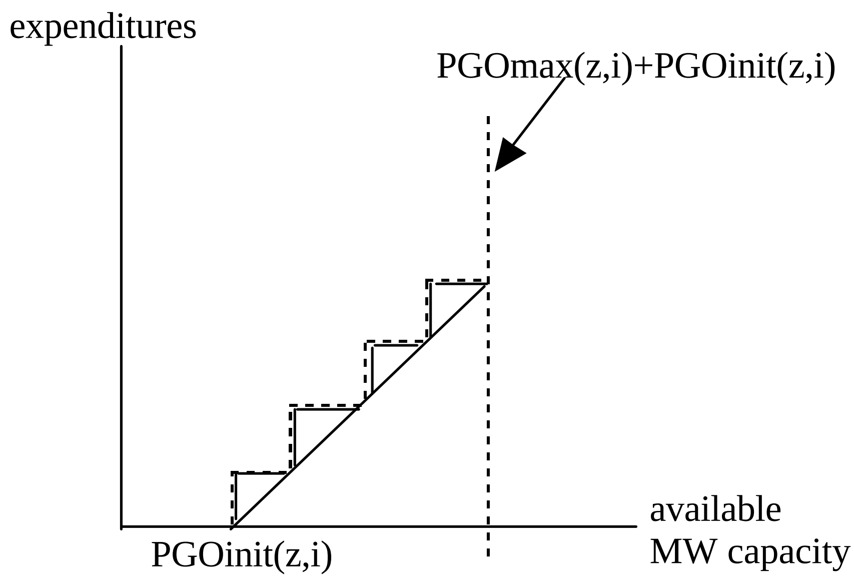
$$\left\{\mathrm{PGOinit}(\mathrm{z},\mathrm{i}) + \sum_{\mathrm{tyb}=1}^{\mathrm{ty}} \mathrm{PGOexpstep}(\mathrm{z},\mathrm{i})\mathrm{PGOexp}(\mathrm{tyb},\mathrm{z},\mathrm{i})\right\} * \text{derate for day type.}$$

PGOexp(ty,z,i) = 0, 1, 2, 3...

Further, the total expansion over all periods at site “i” cannot exceed the maximum additional capacity allowed, “PGOmax(z,i)”; - e.g., letting “T” be the last year of the horizon;

$$\sum_{\mathrm{tyb}=1}^{\mathrm{T}} \mathrm{PGOexpstep}(\mathrm{z},\mathrm{i})\mathrm{PGOexp}(\mathrm{tyb},\mathrm{z},\mathrm{i}) \leq \mathrm{PGOmax}(\mathrm{z},\mathrm{i})$$

FIGURE 4.1b - Expansion as a continuous variable, e.g., “PGOexp(ty,z,i) ≥ 0



Alternatively, Figure 4.1b assumes expansion to be a continuous, rather than in fixed multiples of a given plant size. Here it is assumed that there are enough variations in the size of the units available in the market place to allow the expansion variable to be considered continuous, and then rounded off by the user to the nearest size available for the technology in question. If this assumption is made, the utilization equation is identical in form to the preceding equation, except the variable “PGOexp(tyb,z,i)” is declared positive, rather than integer.

In summary, the capacity constraint for existing thermal units is

$$PG(ty,ts,td,th,z,i) \le \left[PGOinit\,(z,i) + \sum_{tyb=1}^{ty} PGOexpstep(z,i)\,PGOexp(tyb,z,i) \right] derate by\ day\ type$$

$$PGOexp(ty,z,i)\ either\ integer\ (0,1,2,3\ldots)\ or\ positive \ge\ (0)$$

The choice of which to use is up to the user. There is no “free lunch” in modeling; while assuming capacity expansion is possible only by adding multiple units of a given size is closer to reality, the user will pay a substantial run time penalty if that route is taken.

Conversely, if the continuous approach is taken, while run times are dramatically reduced, the error caused by rounding off to the nearest available unit size may cause problems.

Because of construction time lags, no construction is allowed in year 1 - e.g., “PGOexp(“yr1”,z,i)” = 0.

The capacity constraint equation needs to reflect the gradual decay in generating capability as the units age, utilizing the modeling method described previously. Letting “DecayPGO” be the annual decay rate appropriate for each old thermal site (defalut values tabled in the appendix) and recalling that periods can have a user specified number of years “n” per period, (users choose “n” by selecting parameter “DW”), we have the following modification of the capacity constraint for old thermal plants:

$$PG(ty, ts, td, th, z, i) \le \left\{ PGOinit(z, i) + \sum_{tyb=1}^{ty} PGO\exp step(z, i,)PGO\exp(tyb, z, i) \right\} derate\, by\, day\, type$$

$$PGO\exp(ty, z, i)\, either\, int\, eger\, (0, 1, 2, 3\ldots)\, or\, positive \ge (0)$$

where “n(ty)” and “n(ty-τ)” adjust the exponent to account for the differing period lengths.

The forced and unforced outage rate notation for old units is “FORPGO(z,i)” and “UFORPGO(z,i)” respectively (default values are in the appendix); the constraints for the six day types for either assumption - fixed multiple or continuous - are, using GAMS notation, equations “CON9a” to equation “CON9d”; (Main.gms file, section 21 & 22)

```
equation CON9a;    {old thermo plants generation limit of off-peak day}
CON9a(ty,ts,th,z,i) ..
    PG(ty,ts,'offpeak',th,z,i)
=L= (  PGOinit(z,i)*power((1-DecayPGO),DW*ord(ty))
    + sum(tyb$(ord(tyb) LE ord(ty)), PGOexp(tyb,z,i)*PGOexpstep(z,i)
                        *power((1-DecayPGO),DW*(ord(ty)-ord(tyb))))
   )*(1-((28/27)*UFORPGO(z,i)))*(1-FORPGO(z,i));
equation CON9b;    {old thermo plants generation limit of peak day, summer}
CON9b(ty,th,z,i) ..
    PG(ty,'summer','peak',th,z,i)
=L= (  PGOinit(z,i)*power((1-DecayPGO),DW*ord(ty))
    + sum(tyb$(ord(tyb) LE ord(ty)), PGOexp(tyb,z,i)*PGOexpstep(z,i)
                        *power((1-DecayPGO),DW*(ord(ty)-ord(tyb))))
   )*(1-((28/27)*UFORPGO(z,i)))*(1-FORPGO(z,i));

equation CON9c;    {old thermo plants generation limit of peak day, winter}
CON9c(ty,th,z,i) ..
    PG(ty,'winter','peak',th,z,i)
=L=  (  PGOinit(z,i)*power((1-DecayPGO),DW*ord(ty))
     + sum(tyb$(ord(tyb) LE ord(ty)), PGOexp(tyb,z,i)*PGOexpstep(z,i)
                        *power((1-DecayPGO),DW*(ord(ty)-ord(tyb))))
    )*(1-FORPGO(z,i));
```

```
equation CON9d;    {old thermo plants generation limit of average day}
CON9d(ty,ts,th,z,i) ..
    PG(ty,ts,'average',th,z,i)
=L= (  PGOinit(z,i)*power((1-DecayPGO),DW*ord(ty))
    + sum(tyb$(ord(tyb) LE ord(ty)), PGOexp(tyb,z,i)*PGOexpstep(z,i)
                        *power((1-DecayPGO),DW*(ord(ty)-ord(tyb))))

   )*(1-((28/27)*UFORPGO(z,i)))*(1-FORPGO(z,i));
```

Since the space at existing thermal plants is limited, upper limits on the amount of capacity which can be added are required. Table "PGOmax(z,i)" in the appendix lists the limits.
Thus;

$$\sum_{ty=1}^{T} PGO\exp(ty, z, i) PGOexpstep(z, i) \leq PGO\max(z, i)$$

or, in GAMS notation, equation "CON10" is; (Main.gms file, section 22)

```
equation CON10;        {old thermo plants expansion limit}
CON10(z,i) ..
sum(tyb, PGOexp(tyb,z,i)*PGOexpstep(z,i)) =L= PGOmax(z,i);
```

Old Thermal Plants:

Tables "Oexpcost(z,i)", "PGOexpstep(z,i)", and "PGOmax(z,i)", along with variable "PGOexp(τ,z,i)", govern the expansion of old thermal plants. Default values now in the model are:

- expansion step size: 20 to 25% of current capacity
- maximum MW addition: 50 to 100% of current capacity
- expansion cost/MW: 1 million dollars

According to the latest SAPP list of approved optional projects, there are no plans to expand any of the existing plants listed in Table 4.2. Consequently, the default data in Table "PGOmax(z,i)" are set at 0. If users wish to allow expansion, rather than consider only new site construction, they can do so by entering the maximum expansion amount in Table "PGOmax(z,i)", as well as the appropriate expansion cost/MW in Table "Oexpcost(z,i)".

4.2.2 Old Hydro Sites

The same constraints apply to existing hydro generation - that generation in year, “ty” in any period - the variable “Hmw(ty,ts,td,th,z,ih)” -- cannot exceed the sum of properly derated (Table “DecayHO” in the appendix) initial capacity -- “HOinit(z,ih)” (values in the appendix) plus new capacity installed by year “ty”, which is equal to the sum up to and including year “ty” of “HOVexp(ty,z,ih)”, a continuous or integer decision variable, times “HOexpstep(z,ih)”, (tabled in the appendix) e.g. The model derates hydro capacity only by the forced outage rates “(1-FOROH(z,ih))” (tabled in the appendix) since the model assumes preventive maintenance takes place when the reservoir falls below it’s minimum level described below. Thus, only one capacity constraint is needed for all day types.

$$\mathrm{Hmw}(\mathrm{ty},\mathrm{ts},\mathrm{td},\mathrm{th},\mathrm{z},\mathrm{ih}) \le \Big[\mathrm{HOinit}(\mathrm{z},\mathrm{ih})(1-\mathrm{DecayHO})^{n(\mathrm{ty})}$$

$$+\sum_{\mathrm{tye}=1}^{\mathrm{ty}} \mathrm{HOV}\exp(\mathrm{tye},\mathrm{z},\mathrm{ih})\mathrm{HO}\exp\mathrm{step}(\mathrm{z},\mathrm{ih})(1-\mathrm{DecayHO})^{n(\mathrm{ty}-\mathrm{tye})}\Big](1-\mathrm{FOROH}(\mathrm{z},\mathrm{ih}))$$

with “HOVexp(ty,z,ih)” declared a positive or integer variable, depending on user preferences. Again, “HOVexp(“yr1”,z,ih)” = 0

or using the GAMS notation (Main.gms file, section 10)

```
EQUATION HOmw; {Old hydros MW capacity Limit}
HOmw(ty,ts,td,th,z,ih) ..
 H(ty,ts,td,th,z,ih) =L= (HOinit(z,ih)*power((1-DecayHO),DW*ord(ty))
 + sum(tye$(ord(tye) LE ord(ty)), HOVexp(tye,z,ih) *HOexpstep(z,ih)
                        *power((1-DecayHO),DW*(ord(ty)-ord(tye)))))
                        * (1 - FORoh(z,ih));
```

For old dam sites, the assumption is made that additions involve only adding new water turbines/generators to the existing dam; no increase in dam height is assumed possible.

Further, the upper limit on total additions at a site must be respected. Table “HOVmax(z,ih)” in the appendix to this section lists these upper limits on capacity additions;

$$\sum_{\mathrm{ty}=1}^{\mathrm{T}} \mathrm{HOV}\exp(\mathrm{ty},\mathrm{z},\mathrm{ih})\mathrm{HOexpstep}(\mathrm{z},\mathrm{ih}) \le \mathrm{HOV}\max(\mathrm{z},\mathrm{ih})$$

or in GAMS format, equation “HOlimit” is; (Main.gms file, section 10)

```
EQUATION HOlimit; {Old hydros maximum additional Capacity limit}
HOlimit(z,ih) ..
sum(ty, HOVexp(ty,z,ih)*HOexpstep(z,ih)) =L= HOVmax(z,ih);
```

Additional capacity constraints are needed for the hydro units to reflect the fact that the water supply, and hence the amount of electricity which can be generated in a season, is limited by the reservoir’s capacity and inflow.

The model distinguishes between two types of existing hydro sites – run of river and dam – by requiring the total KWh generation constraint for run of the river to hold separately for each of the two seasons in the model, while the total KWh constraint for dams holds over both seasons. Since site expansion is assumed to be limited to increasing MW generating capacity and does not effect the volume of water capable of being stored, the MW expansion variable “HOVexp” does not enter the right hand side of either of these water supply equations. Thus:

CASE A: Run of River

$$\sum_{td,th} H(ty, winter, td, th, z, ih) \le HROmwh(winter, z, ih) fdrought(ty)$$

$$\sum_{td,th} H(ty, summer, td, th, z, ih) \le HROmwh(summer, z, ih) fdrought(ty)$$

CASE B: Dams

For dams, we have the single yearly equation;

$$\sum_{ts,td,th} H(ty, ts, td, th, z, ih) \le HDOmwh(z, ih) fdrought(ty)$$

where “HROmwh(z,ih)” and “HDOmwh(z,ih)” in the appendix are the parameters giving the limit on run of river and dams KWh use over the period, and “fdrought(ty)” is a user specified parameter between 0 and 1 to reflect reductions in water availability in drought periods during the planning horizon. In the absence of actual energy (MWh) capacity of the hydro sites, the following method was used to estimate “HRO” and “HDO”. For both types, the maximum energy available in a season is initially given by multiplying the site’s power (MW) capacity “HOinit(z,ih)” for existing sites, by the total time (hours) in that season, “thT*tdT” (hours/day)*(days/season). For a site having a dam, a further seasonal catchment factor “fdamO(z,ih,ts)” (in the appendix) is used to estimate how much water inflow (energy) the dam receives in each season, recognizing the fact that more water comes in during the rainy summer season than the dry winter season. Therefore, the maximum energy available from an existing run of river site is given by

HROmwh(z,ih) = HOinit(z,ih)*thT*tdT, and for a dam;

HDOmwh(z,ih) = HOinit(z,ih)*thT*tdT*[fdamO(z,ih,summer) + fdamO(z,ih,winter)]

Currently, only dams are in the SAPP construction plans; thus, in GAMS notation, equation “MWhODam” is; (Main.gms file, section 10)

<u>Dams</u>

```
EQUATION MWhODam; {Annual MWh capacity limit for Existing Dams}
MWhODam(ty,z,ih) ..
sum((ts,td,th), H(ty,ts,td,th,z,ih))=L= fdrought(ty) * HDOmwh(z,ih);
```

and the limit on out flow per year is (Hydro.inc file, section 6)

```
Parameter HDOmwh(z,ih); {annual MWh capacity of Existing DAM type hydro}
HDOmwh(z,ih) =  HOinit(z,ih)*(tdT*thT)*sum(ts,fdamO(z,ih,ts));
```

According to the latest (December 1, 1998) data provided by SAPP, only four of the existing hydro sites are now being considered for expansion - Cambambe extension in Angola, Cahora Bassa N. extension in NMZ, Kariba North extension in Zambia, and Kariba South extension in Zimbabwe (the latter two will be considered in the model only if Batoka is undertaken).

Thus, the default data in the model allow only expansions of these four sites to be considered, and Tables “HOVmax(z,ih)” (maximum expansion in MW), “HOexpstep(z,ih)” (expansion step size in MW), and “HOVcost(z,ih)” (expansion cost, in $ per MW) only contain the data found in Table 4.2 concerning these four expansions. If, at a later time, users wish to allow expansion of other sites to be considered, they may do so by entering the values for such expansions in these tables.

4.2.3 New Thermal Plants

A distinction needs to be made between new sites, new plants, and new units before proceeding. Each region has a given number of potential new generation sites which, if economic, can be developed by construction of new generating plants of varying types. The capacity of these plants, once the initial site development expense has been made, can be added to by investment in additional generating units. The plant options in each region are restricted by fuel availability in the region - e.g., only SAPP members with gas available, or expected to be available, can purchase simple or combined cycle gas turbines.

In addition to units planned by SAPP members in Table 4.2, the model will allow four thermal options to be built on a given site, based on the latest plant cost and performance data available in the U.S.;

- Plant type “T” – a small simple cycle advanced gas combustion turbine of the type used to meet peak demand in the U.S. They can be purchased in a variety of sizes. The default data in the model are based on a 50 MW plant (Table “NTexpstep” in the model) with a net heat rate of 11,250 BTU/KWh (Table “HRNT” in model), a total capital cost of $15 million (Table “NTexpcost” in the model), “O&M” cost of $.0086/KWh, capable of 1752 hours/year at full load (turbo power FT8 twin). Fuel costs in cents/BTU are entered in Table “fpNT”; escalation rates in “fpescNT”. The model allows all countries except MWI, NMZ, SWZ, DRC, and ZAM to build up to 9 of these plants on 3 separate sites in a given period.
- Plant type “CC” – a 250 MW initial capacity (Table “PGNCCinit” in the model) combined-cycle gas combustion turbine unit with a net heat rate of 7490 BTU/Kwh (Table “HRNCC” in the model), capable of running 7446 hours/year at full load. The initial fixed cost for the 250 MW unit is $109 million ($440/KW) (Table “FGCC” in the model); additional MW (variable “PGNCCexp” in the model) can be added at a cost of $412/KW (Table “NCCexpcost(z,ni)” in the model) up to a maximum of 750 MW per

site (Table "PGNCCmax" in model). "O&M" costs are $0.0042/KWh (SEPRIL data). Fuel costs are entered in Table "fpNCC"; escalation rates in "fpescNCC". NAM, ANG, TAZ, SSA, and SMOZ are allowed to build these plants.

- Plant type "LC" – a 500 MW initial capacity (scalar "PGNLCinit" in the model) pulverized coal unit with a net heat rate of 9800 BTU/KWh (Table "HRNLC" in the model), capable of running 7446 hours at full load. The initial fixed cost for the unit is $581 million ($1160/KW) (Table "FGLC" in the model); additional MW (variable "PGNLCexp") can be added at a cost of $866/KW (Table "NLCexpcost" in the model) up to a maximum of 4500 MW per site (Table "PGLCmax" in the model). "O&M" costs are $0.0067/KWh (SEPRIL data). Fuel costs are entered in Table "fpNLC"; escalation rates in "fpescNLC". Only SSA is allowed to build plants of this type.
- Plant type "SC" – a small fixed capacity 300 MW (Table "NSCexpstep") subcritical coal-fired plant with a heat rate of 9800 BTU/KWh (Table "HRNSC" in model) capable of running 7446 hours a full load. The initial capital cost is $430 million; ($1433/KW) (Table "NSCexpcost") "O&M" costs are $0.0089/KWh (SEPRIL data). Fuel costs are entered in Table "fpNSC"; escalation rates in "fpescSC". The model allows all countries except ZAM, DRC, MOZ, and NAM to build these plants.

Each of the regions where "SC" are allowed can have up to two new sites per time period; RSA can have up to eight new large coal sites. All regions where "CC" & "T" are options are allowed up to three new combined cycle and combustion turbine sites.

For purposes of dispatch, all the units of a given plant type are available for joint dispatch - e.g. - "CC" plant generation is constrained only by the total installed "CC" plant capacity at a given site.

The four plant types can be broken down into two categories; those with scale economies, and those without. Plant types which have no scale economies - combustion turbines and small coal units - have the characteristic that if additional capacity of this type is needed beyond the initial capacity, only replicas of the initial units which have identical costs and performance can be added to increase capacity.

The second type of new plant - large coal plants and combined cycle plants - are assumed to exhibit economies of scale, in that after installation of their initial capacity, each can add additional capacity in the form of units with lower capital cost. (This is made possible by oversizing the original plant and site infrastructure.)

In cases where the need for additional capacity is not recurring and/or interest rates are high, small plants with no provision for growth are the preferred choice. When the need for additional capacity is immediate and continuing and/or interest rates are low, plants with high initial development costs, but much lower expansion costs, are to be preferred.

In the case of combustion turbine ("CT") and small coal ("SC") plants, additional capacity can be added only by constructing replicas of the original plants.

In the case of large combined cycle ("CC") and large coal plants ("LC"), capacity can be increased in two ways - adding new plants, as is the situation for "CT" and "SC", and adding cheaper units to plant sites already developed.

4.2.4 Combustion Turbines and Small Coal Units

The default technical parameters which enter into the capacity constraints of the two technologies - unit capacity "NTexpstep(z,ni)" and "NSCexpstep(z,ni)", forced and unforced outage rates "FORNT(z,ni)", "UFORNT(z,ni)", "FORSC(z,ni)", and "UFORSC(z,ni)" - are given in the appendix to this chapter. Users can input their own values to reflect specific site parameters.

Since the small gas turbines modeled here are not designed to be operated continuously, but only during periods of peak demand, their use in the model is restricted to the peak periods in the model, here taken to be the 52 peak days of each week, or 1248 hours/year.

The decision to build a plant at site "ni" is reflected in the value of the decision variable "PGNTexp(ty,z,ni)" for the "CT", and "PGNSCexp(ty,z,ni)" for the small coal unit. The model allows the user to specify how the construction of new "CT" and "SC" plants are to be modeled - as a continuous variable, or in fixed sizes. In both cases, the fixed capacities (step widths) are specified in Tables "PGNTinit(z,ni)" and "PGNSCinit(z,ni)", with default values set at 50 and 300 MW respectively. The choice of continuous versus fixed expansion is made by declaring the decision variables "PGNTexp(ty,z,ni)" and "PGNSCexp(ty,z,ni)" either continuous, or integer. Figures 4.2a and 4.2b show the plot of available capacity and cost if fixed multiples (4.2a) or continuous (4.2b) expansion is chosen.

Figure 4.2a: expansion as fixed multiples of a given plant size; "PGNexp(ty,z,ni)" = 0,1,2,3,...

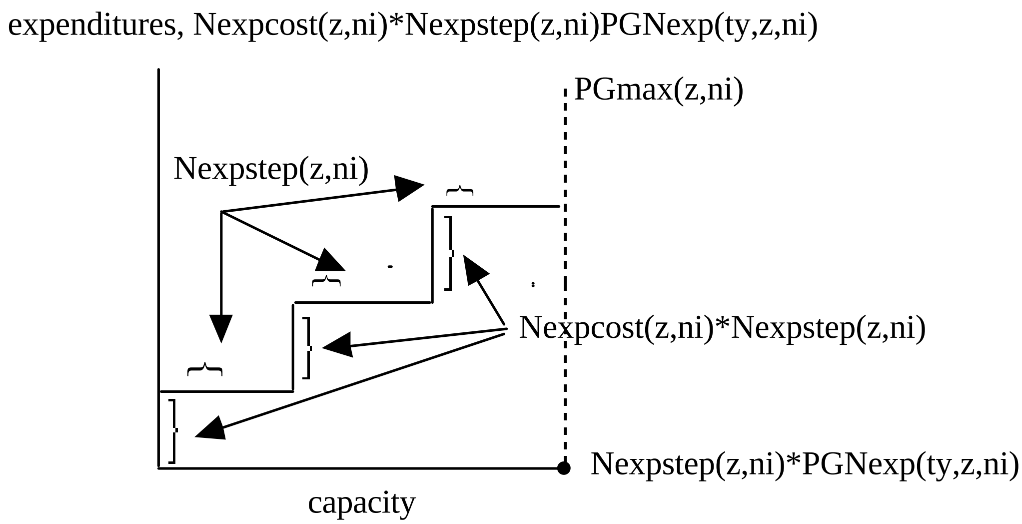
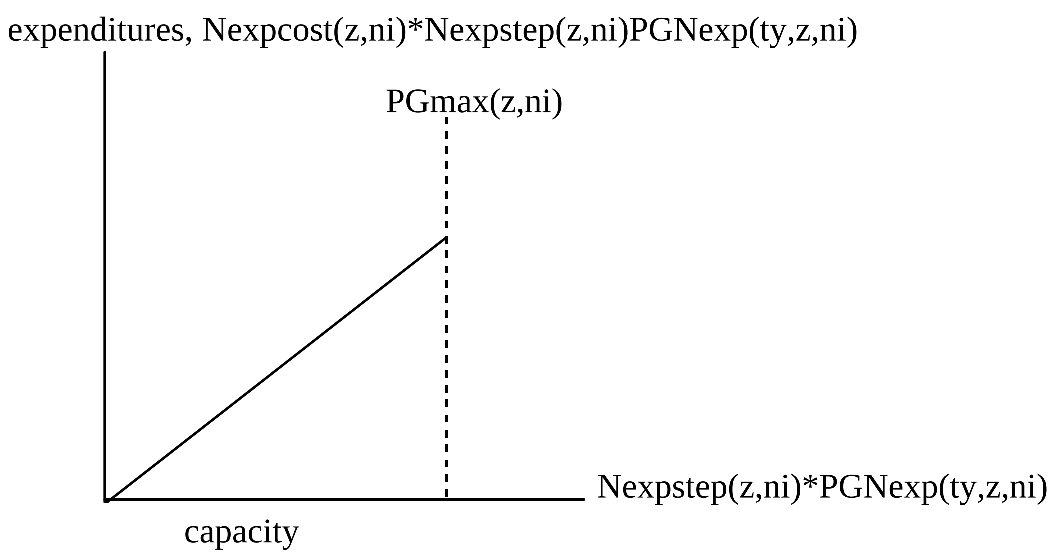


Figure 4.2b: expansion as a continuous variable; "PGNexp(ty,z,ni)" ≥ 0



If "NTexpstep(z,ni)" and "NSCexpstep(z,ni)" are the fixed capacities of these units, and "DecayNT" and "DecayNSC" the aging factors, the capacity constraints are of a simple form:

$$\mathrm{PGNT(ty, ts, td, th, z, ni)} \le$$

$$\left[\left(\sum_{\tau=1}^{ty} \mathrm{PGNTexp}(\tau, \mathrm{z, ni})\mathrm{NTexpstep(z, ni)}\right)(1 - \mathrm{DecayNT})^{n(ty-\tau)}\right]\text{Derate for day type}$$

with "PGNTexp(ty,z,ni)" either positive or integer.

Further, the upper limit on site capacity is;

$$\sum_{\tau=1}^{T} \mathrm{PGNTexp}(\tau, \mathrm{z, ni})\mathrm{NTexpstep(z, ni)} \le \mathrm{PGNTmax(z, ni)}$$

For the small coal units;

$$\mathrm{PGNSC(ty, ts, td, th, z, ni)} \le$$

$$\left[\left(\sum_{\tau=1}^{ty} \mathrm{PGSCexp(t, z, ni)NSCexpstep(z, ni)}\right)(1 - \mathrm{DecaySC})^{n(ty-\tau)}\right]\text{Derate for day type}$$

with "PGSCexp(ty,z,ni)" either positive or integer, and

$$\sum_{\tau=1}^{T} \mathrm{PGSCexp(t, z, ni)NSCexpstep(z, ni)} \le \mathrm{PGNSCmax(z, ni)}$$

Tables "PGNTmax(z,ni)" and "PGNSCmax(z,ni)" give the maximum expansion per site allowed for these two technologies. Default values are 450 MW for "CT" and 600 MW for "SC".

These equations in GAMS format for each of the 6 day types are given below in equations "CON1a-d", "CON3a-d", "CON7", and "CON8"; (Main.gms file, section 17, 18, 19, 20, & 21)

```
equation CON1a;      {new gas turbine generation limit of off-peak day for both seasons}
CON1a(ty,ts,th,z,ni) ..
   PGNT(ty,ts,'offpeak',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNTexp(tyb,z,ni)*NTexpstep(z,ni)
                      *power((1-DecayNT),DW*(ord(ty)-ord(tyb))))
   *(1-((28/27)*UFORNT(z,ni)))*(1-FORNT(z,ni));

equation CON1b;      {new gas turbine generation limit of peak day, summer}
CON1b(ty,th,z,ni) ..
   PGNT(ty,'summer','peak',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNTexp(tyb,z,ni)*NTexpstep(z,ni)
                      *power((1-DecayNT),DW*(ord(ty)-ord(tyb))))
   *(1-((28/27)*UFORNT(z,ni)))*(1-FORNT(z,ni));

equation CON1c;      {new gas turbine generation limit of peak day, winter}
CON1c(ty,th,z,ni) ..
   PGNT(ty,'winter','peak',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNTexp(tyb,z,ni)*NTexpstep(z,ni)
                      *power((1-DecayNT),DW*(ord(ty)-ord(tyb))))
   *(1-FORNT(z,ni));

equation CON1d;      {new gas turbine generation limit of average day for both seasons}
CON1d(ty,ts,th,z,ni) ..
   PGNT(ty,ts,'average',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNTexp(tyb,z,ni)*NTexpstep(z,ni)
                      *power((1-DecayNT),DW*(ord(ty)-ord(tyb))))
   *(1-((28/27)*UFORNT(z,ni)))*(1-FORNT(z,ni));

equation CON3a;      {new small coal generation limit of off-peak day}
CON3a(ty,ts,th,z,ni) ..
   PGNSC(ty,ts,'offpeak',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)
                      *power((1-DecayNSC),DW*(ord(ty)-ord(tyb))))
   *(1-((28/27)*UFORNSC(z,ni)))*(1-FORNSC(z,ni));

equation CON3b;      {new small coal generation limit of peak day, summer}
CON3b(ty,th,z,ni) ..
   PGNSC(ty,'summer','peak',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)
                      *power((1-DecayNSC),DW*(ord(ty)-ord(tyb))))
   *(1-((28/27)*UFORNSC(z,ni)))*(1-FORNSC(z,ni));

equation CON3c;      {new small coal generation limit of peak day, winter}
CON3c(ty,th,z,ni) ..
   PGNSC(ty,'winter','peak',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)
                      *power((1-DecayNSC),DW*(ord(ty)-ord(tyb))))
   *(1-FORNSC(z,ni));

equation CON3d;      {new small coal generation limit of average day}
CON3d(ty,ts,th,z,ni) ..
   PGNSC(ty,ts,'average',th,z,ni)
=L= sum(tyb$(ord(tyb) LE ord(ty)),PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)
                      *power((1-DecayNSC),DW*(ord(ty)-ord(tyb))))
   *(1-((28/27)*UFORNSC(z,ni)))*(1-FORNSC(z,ni));
```

```
equation CON7;          {expansion limit for gas turbine}
CON7(z,ni) ..
sum(tyb, PGNTexp(tyb,z,ni)*NTexpstep(z,ni)) =L= PGNTmax(z,ni);

equation CON8;          {expansion limit for small coal}
CON8(z,ni) ..
sum(tyb, PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)) =L= PGNSCmax(z,ni);
```

4.2.5 Large Combined Cycle and Large Coal Plants

As in the case of existing capacity, Figures 4.3a and 4.3b show two possible ways of modeling total equipment cost as a function of capacity installed at new sites, when scale economies are present. Both assume that the fixed cost “FG(z,ni)” of installing the initial capacity “PGNinit(z,i)” (tabled in the appendix) is substantial, including as it does the cost of site acquisition and preparation, connections to the grid and fuel handling equipment, all oversized to allow add on capacity at lower incremental cost. Both assume the initial investment is a fixed cost, in that it must be paid in its entirety, or not at all. Thus, the decision to develop the initial site and install the initial capacity is always controlled by the binary variables “YLC(ty,z,ni)” for large coal, and “YCC(ty,z,ni)” for combined cycle plants. Both also have an upper limit on the add-on capacity, “PGNLCmax(z,ni)” and “PGNCCmax(z,ni)” in the appendix, set by the size of the initial site. As in the case of old capacity expansion, the two figures differ in their handling of the capacity expansion itself, the variables “PGNLCexp(ty,z,ni)” and “PGNCCexp(ty,z,ni)”. Figure 4.3a assumes that additions are available only in fixed sizes - e.g. “x” MW units - while figure 4.3b assumes that there are enough variations in size in the units which can be purchased to allow the expansion variable to be continuous, and then rounded off to the nearest size available for that technology.

Thus for the combined cycle plant, the approach used in Figure 4.3a would add capacity in multiples of 250 MW each, while the approach in Figure 4.3b would add continuous MW capacity, which would then be rounded off to the nearest purchasable mix of units.

<u>Option #1:</u> Fixed increments of additional capacity. (Figure 4.3a)

In this formulation, capacity additions at a given site “ni” in a given year “ty” are the product of a parameter “NCCexpstep(z,ni)” for “CC”, “NLCexpstep(z,ni)” for “LC” which gives the user specified MW size of the units to be added, (tabled in the appendix: default values 250 MW and 500 MW for “CC” and “LC” respectively) times the integer variable “PGNCCexp(ty,z,ni)” for “CC”, “PGNLCexp(ty,z,ni)” for “LC”, which gives the number of units added in year “ty”. For example, if the expansion step is 250 MW, and the binary variable is chosen 1 in year “ty” then (1.)(250) = 250 MW would be added in the year.

<u>Option #2:</u> Continuously variable capacity. (Figure 4.3b)

In this formulation, the parameters “NCCexpstep(z,ni)” and “NLCexpstep(z,ni)” are kept the same, but the variables “PGNCCexp(ty,z,ni)” and “PGNLCexp(ty,z,ni)” are declared positive, continuous variables, rather than integer variables. In the example, if the continuous variable was chosen in year “ty” to be 1.5, then (1.5)(250) = 375 MW would be added in the year.

As before, the choice is up to the user. While the “lumpy” nature of the additions is closer to reality, the user will pay a substantial run time penalty, if that route is taken.

In both cases, the decision to develop and build the initial site is separate from the decision to expand the capacity of the site, once it is built. The decision to spend “FGCC(z,ni)” or “FGLC(z,ni)” to initially develop the site and install “PGNCCinit(z,ni)” or “PGNLCinit(z,ni)” MW of capacity are determined in the model by the value of the binary variables “YCC(ty,z,ni)” or “YLC(ty,z,ni)” which are 1 if the site is developed; if “YCC(ty,z,ni)” or “YLC(ty,z,ni)” are 0, then nothing takes place.

Figure 4.3a: New plant initial construction, with expansion as fixed multiples of a given size, e.g. "PGNexp(ty,z,ni)" = 0,1,2,3

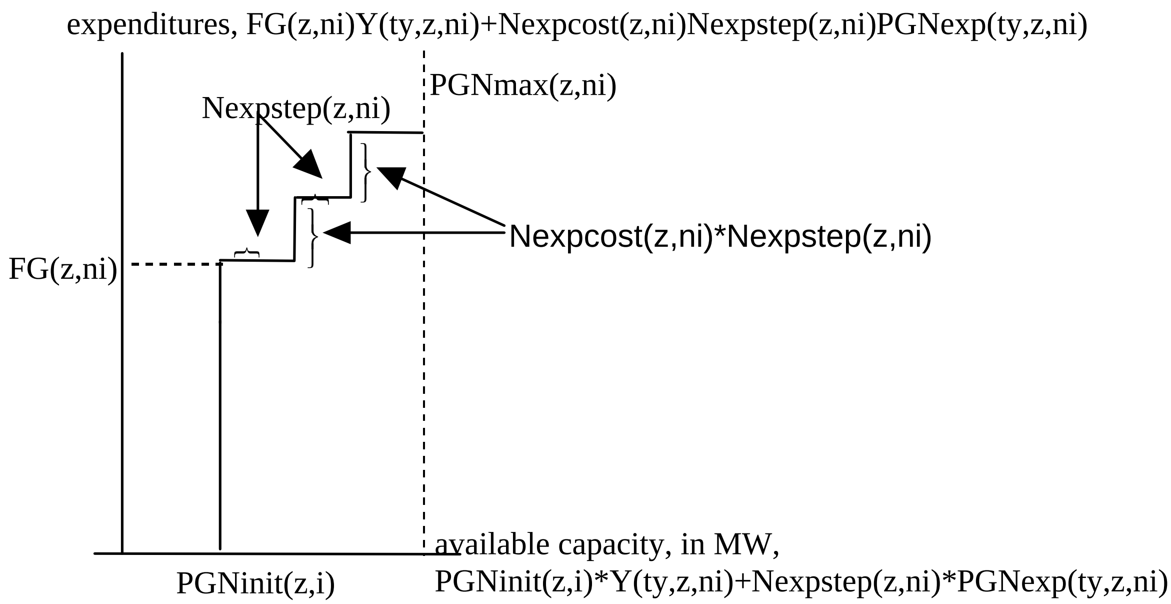
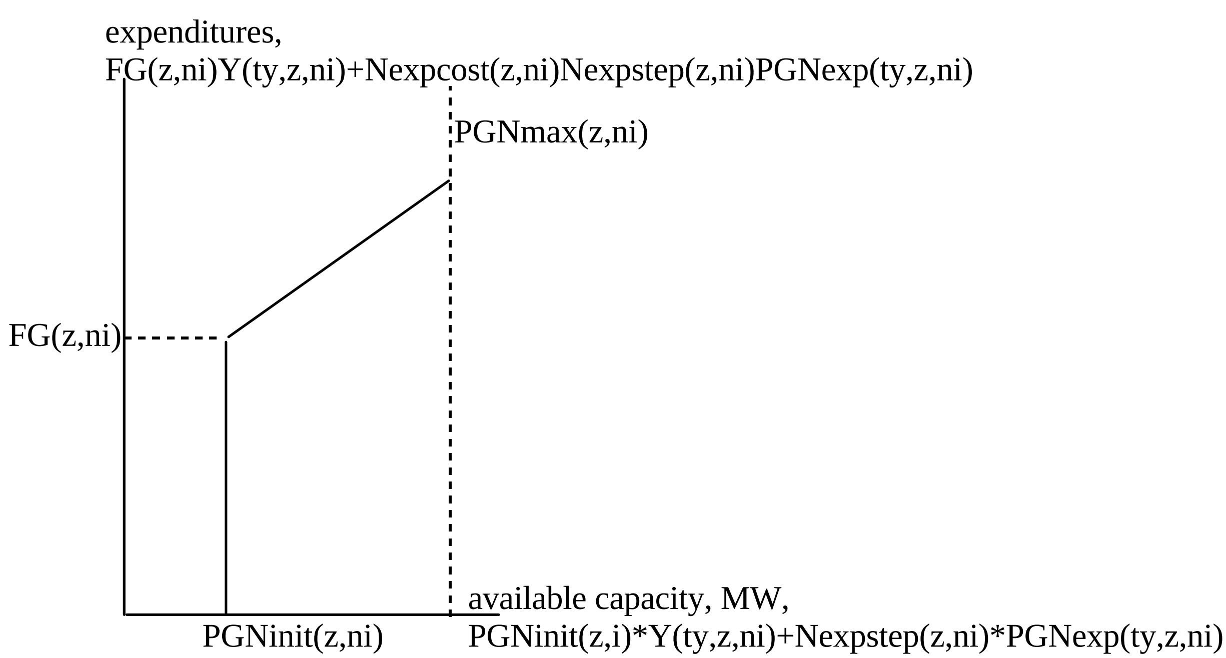


Figure 4.3b: New plant initial construction, with continuous expansion. e.g., "PGNexp(ty,z,ni)" ≥ 0



Both formulations require that however capacity expansion is modeled, total expansion cannot exceed the upper limit on installed capacity at a site “PGNCCmax(z,ni)” or “PGNLCmax(z,ni)”, in the appendix.

Each period, at most one new plant of a given type can be added to a new site.

As stated previously, additional generating units can be added to the new sites at any time, as long as the capacity of the plants to add units is not exceeded. Each new plant at a site, then, has three parameters critical to the capacity constraints:

- “PGNCCinit(z,ni)” and “PGNLCinit(z,ni)”, the initial plant capacity installed when the new site is first constructed, unaltered by how much capacity additions are treated; (default values are 250 for “CC”, 500 for “LC”)
- “NCCexpstep(z,ni)” and “NLCexpstep(z,ni)”, the MW size of units added to a plant, once one is built at site “ni”. This parameter is set at the unit size selected by the user. (Default values are 250 MW for “CC”, 500 for “LC”).
- “PGNCCmax(z,ni)” and “PGNLCmax(z,ni)”, the upper limit on the total MW capacity which can be added by additional units to the plant; (default values are 750 MW for “CC” 4500 for “LC”)

All are listed in the appendix for the two technologies.

The decision variables “PGNCCexp(ty,z,ni)” and “PGNLCexp(ty,z,ni)” are either integer variables, if a fixed step size is selected, or continuous variables. In all cases year 1 variables are zero, to reflect the fact that the required construction lead time is too long to allow new plant to be available in the first period.

With these conventions - sites are allowed to build one new plant per period per technology, plants can augment the initial plant capacity by adding units up to a specified maximum per plant, and all units in all plants at a site will be dispatched collectively - and “DecayNCC” and “DecayNLC” the aging factors (tabled in the appendix), the capacity constraints for both the “CC” and “LC” technologies can be stated.

For “CC”, we have;

$$\mathrm{PGNCC}(\mathrm{ty},\mathrm{ts},\mathrm{td},\mathrm{th},\mathrm{z},\mathrm{ni}) \le \Bigg[\mathrm{PGNCCinit}(\mathrm{z},\mathrm{ni}) \sum_{\mathrm{tya}=1}^{\mathrm{ty}} \mathrm{YCC}(\mathrm{tya},\mathrm{z},\mathrm{ni})(1-\mathrm{DecayNCC})^{n(\mathrm{ty}-\mathrm{tya})}$$

$$+ \sum_{\mathrm{tyb}=1}^{\mathrm{ty}} \mathrm{PGNCC}\exp(\mathrm{tyb},\mathrm{z},\mathrm{ni})\mathrm{NCC}\exp\mathrm{step}(\mathrm{z},\mathrm{ni})(1-\mathrm{DecayNCC})^{n(\mathrm{ty}-\mathrm{tyb})} \Bigg] \text{derate for day type}$$

$$\text{where } \mathrm{YCC}(\mathrm{tya},\mathrm{z},\mathrm{ni}) = \{0,1\}, \mathrm{PGNCC}\exp(\mathrm{tyb},\mathrm{z},\mathrm{ni}) \text{ either } \ge 0 \text{ or} = 0,1,2,3, \text{etc.}$$

e.g. in year “ty”, the dispatch limit at site “ni” is equal to the number of plants built on the site as of year “ty” times their initial capacity plus the capacity added to these plants as of “ty”. Further,

$$\sum_{\mathrm{tya}=1}^{\mathrm{ty}} \mathrm{NCCexpstep}(\mathrm{z},\mathrm{ni})\mathrm{PGNCC}\exp(\mathrm{tya},\mathrm{z},\mathrm{ni})$$

$$\le \sum_{\mathrm{tya}=1}^{\mathrm{ty}} \mathrm{YCC}(\mathrm{tya},\mathrm{z},\mathrm{ni})\mathrm{PGNCCmax}(\mathrm{z},\mathrm{ni})$$

e.g. the upper limit on capacity added to all plants built at site “ni” up to “ty” is set by the number of plants built as of year “ty” times the upper limit on the capacity which can be added.

The limit of large coal generation at site “ni” in country “z” is:

$$\mathrm{PGNLC}(\mathrm{ty},\mathrm{ts},\mathrm{td},\mathrm{th},\mathrm{z},\mathrm{ni}) \le \Bigg[\mathrm{PGNLCinit}(\mathrm{z},\mathrm{ni}) \sum_{\mathrm{tya}=1}^{\mathrm{ty}} \mathrm{YLC}(\mathrm{tya},\mathrm{z},\mathrm{ti})(1-\mathrm{DecayNLC})^{n(\mathrm{ty}-\mathrm{tya})}$$

$$+ \sum_{\mathrm{tyb}=1}^{\mathrm{ty}} \mathrm{PGNLC}\exp(\mathrm{tyb},\mathrm{z},\mathrm{ni})\mathrm{NLCexstep}(\mathrm{z},\mathrm{ni})(1-\mathrm{DecayNLC})^{n(\mathrm{ty}-\mathrm{tyb})} \Bigg] \text{derate for day type}$$

where “YLC(tya,z,ni)” = {0,1}, “PGNLCexp(tyb,z,ni)” either ≥ 0 or = 0,1,2,3,etc.

and

$$\sum_{tya=1}^{ty} PGNLC\exp(tya,z,ni) * NLC\exp step(z,ni) \leq$$

$$\sum_{tya=1}^{ty} YLC(tya,z,ni) PGNLC\max(z,ni)$$

The appendix to this section contains the current values for the parameters which enter into the capacity expansion constraints. In particular; Tables "PGNLCinit(z,ni)" to Table "PGNCCinit(z,ni)" give the initial capacities and the number of sites allowed to be constructed for each region "z": Tables "NCCexpstep(z,ni)" and "NLCexpstep(z,ni)" give the expansion steps for the two types of units where it is allowed, and Tables "PGNLCmax(z,ni)" and "PGNCCmax(z,ni)" give the maximum additional capacity allowed per plant.

As in the case of the capacity constraints on existing sites, the installed capacities of new sites need to be derated for new plant forced outage rates (Tables "FORN- -(z,ni)" in the appendix) during peak days, and both forced and unforced outage rates (Tables "UFORN- -(z,ni)") for off peak days. The equations which enforce the six day type capacity constraints for new sites are given below in GAMS format, followed by the expansion limit constraints, in equations "CON2a-d", "CON4a-d", "CON5", and "CON6". (Main.gms file, sections 18, 19, 20, & 21)

```
equation CON2a;   {new combined cycle generation limit of off-peak day}
CON2a(ty,ts,th,z,ni) ..
    PGNCC(ty,ts,'offpeak',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNCCinit(z,ni)*YCC(tya,z,ni)
                        *power((1-DecayNCC),DW*(ord(ty)-ord(tya))))
   +sum(tyb$(ord(tyb) LE ord(ty)),PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)
                        *power((1-DecayNCC),DW*(ord(ty)-ord(tyb))))
   )*(1-((28/27)*UFORNCC(z,ni)))*(1-FORNCC(z,ni));

equation CON2b;   {new combined cycle generation limit of peak day, summer}
CON2b(ty,th,z,ni) ..
    PGNCC(ty,'summer','peak',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNCCinit(z,ni)*YCC(tya,z,ni)
                        *power((1-DecayNCC),DW*(ord(ty)-ord(tya))))
   +sum(tyb$(ord(tyb) LE ord(ty)),PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)
                        *power((1-DecayNCC),DW*(ord(ty)-ord(tyb))))
   )*(1-((28/27)*UFORNCC(z,ni)))*(1-FORNCC(z,ni));
```

```
equation CON2c;   {new combined cycle generation limit of peak day, winter}
CON2c(ty,th,z,ni) ..
   PGNCC(ty,'winter','peak',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNCCinit(z,ni)*YCC(tya,z,ni)
                     *power((1-DecayNCC),DW*(ord(ty)-ord(tya))))
  +sum(tyb$(ord(tyb) LE ord(ty)),PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)
                     *power((1-DecayNCC),DW*(ord(ty)-ord(tyb))))
  )*(1-FORNCC(z,ni));

equation CON2d;   {new combine cycle generation limit of average day}
CON2d(ty,ts,th,z,ni) ..
   PGNCC(ty,ts,'average',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNCCinit(z,ni)*YCC(tya,z,ni)
                     *power((1-DecayNCC),DW*(ord(ty)-ord(tya))))
  +sum(tyb$(ord(tyb) LE ord(ty)),PGNCCexp(tyb,z,ni)* NCCexpstep(z,ni)
                     *power((1-DecayNCC),DW*(ord(ty)-ord(tyb))))
  )*(1-((28/27)*UFORNCC(z,ni)))*(1-FORNCC(z,ni));

equation CON4a;      {new large coal generation limit of off-peak day}
CON4a(ty,ts,th,z,ni) ..
   PGNLC(ty,ts,'offpeak',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNLCinit(z,ni)*YLC(tya,z,ni)
                     *power((1-DecayNLC),DW*(ord(ty)-ord(tya))))
  +sum(tyb$(ord(tyb) LE ord(ty)),PGNLCexp(tyb,z,ni)*NLCexpstep(z,ni)
             *power((1-DecayNLC),DW*(ord(ty)-ord(tyb))))
  )*(1-((28/27)*UFORNLC(z,ni)))*(1-FORNLC(z,ni));

equation CON4b;      {new large coal generation limit of peak day, summer}
CON4b(ty,th,z,ni) ..
   PGNLC(ty,'summer','peak',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNLCinit(z,ni)*YLC(tya,z,ni)
                     *power((1-DecayNLC),DW*(ord(ty)-ord(tya))))
  +sum(tyb$(ord(tyb) LE ord(ty)),PGNLCexp(tyb,z,ni)* NLCexpstep(z,ni)
                     *power((1-DecayNLC),DW*(ord(ty)-ord(tyb))))
  )*(1-((28/27)*UFORNLC(z,ni)))*(1-FORNLC(z,ni));

equation CON4c;      {new large coal generation limit of peak day, winter}
CON4c(ty,th,z,ni) ..
   PGNLC(ty,'winter','peak',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNLCinit(z,ni)*YLC(tya,z,ni)
                     *power((1-DecayNLC),DW*(ord(ty)-ord(tya))))
  +sum(tyb$(ord(tyb) LE ord(ty)),PGNLCexp(tyb,z,ni)*NLCexpstep(z,ni)
                     *power((1-DecayNLC),DW*(ord(ty)-ord(tyb))))
  )*(1-FORNLC(z,ni));

equation CON4d;      {new large coal generation limit of average day}
CON4d(ty,ts,th,z,ni) ..
   PGNLC(ty,ts,'average',th,z,ni)
=L=(sum(tya$(ord(tya) LE ord(ty)),PGNLCinit(z,ni)*YLC(tya,z,ni)
                     *power((1-DecayNLC),DW*(ord(ty)-ord(tya))))
  +sum(tyb$(ord(tyb) LE ord(ty)),PGNLCexp(tyb,z,ni)*NLCexpstep(z,ni)
                     *power((1-DecayNLC),DW*(ord(ty)-ord(tyb))))
  )*(1-((28/27)*UFORNLC(z,ni)))*(1-FORNLC(z,ni));
```

```
equation CON5;          {expansion can be put only after construction}
CON5(ty,z,ni) ..        {for new combine cycle plants}
   sum(tyb$(ord(tyb) LE ord(ty)), PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni))
=L= sum(tya$(ord(tya) LE ord(ty)), YCC(tya,z,ni)*PGNCCmax(z,ni));

equation CON6;          {expansion can be put only after construction}
CON6(ty,z,ni) ..        {for new large coal plants}
   sum(tyb$(ord(tyb) LE ord(ty)), PGNLCexp(tyb,z,ni)*NLCexpstep(z,ni))
=L= sum(tya$(ord(tya) LE ord(ty)), YLC(tya,z,ni)*PGNLCmax(z,ni));
```

4.2.6 The Treatment of SAPP approved New Thermal Plants

At the current (January 1999) time, there are 15 SAPP new thermal plant construction projects listed in Table 4.2:

Small Coal Projects (10 in total)

- Botswana's Moropule extension, decision variable "PGNSCexp(ty, "BOT",1)" consisting of 2 units of 120 MW each, will be treated as a new small coal site, with the step size "NSCexpstep("Bot",1)" equal to 120 MW, "PGNSCmax("BOT",1)" equal to 240 MW, and the expansion cost/MW, "NSCexpcost("BOT",1)" equal to \$1.75 million/MW. Since no heat rates or fuel costs have been provided, default values (9800 BTU/KWh, \$.40/10^6 BTU) will be used.
- Mozambique's Moatize plant, decision variable "PGNSCexp(ty, "MOZ",1)" consisting of 3 units of 250 MW each, will have a step size "NSCexpstep("MOZ",1)" equal to 250 MW, "PGNSCmax("Moz",1)" equal to 750 MW, and an expansion cost/MW, "NSCexpcost("Moz",1)" of \$1.26 million/MW. Default values for heat rates and fuel costs are again 9800 BTU/KWh and \$.40/10^6 BTU.
- South Africa's Komati A site, decision variable "PGNSCexp(ty, "NSA",1)" consisting of 5 units of 90 MW each, will have a step size "NSCexpstep("NSA",1)" equal to 90 MW, "PGNSCmax("NSA",1)" equal to 450MW, and a re-commission cost/MW, "NSCexpcost("NSA",1)" of \$.277 million/MW. A heat rate of 12876 BTU/KWh and a fuel cost of \$.40/10^6 BTU are used, taken from SAPP data.
- South Africa's Grootvlei site, decision variable "PGNSCexp(ty, "NSA",2)" consisting of 6 units of 190 MW each, will have a step size "NSCexpstep("NSA,2)", equal to 190 MW, "PGNSCmax("NSA",2)" equal to 1140 MW, and a re-commissioning cost "NSCexpcost("NSA",2)" of \$.109 million/MW. A heat rate of 12,186 BTU/KWh and a fuel cost of \$.60/10^6 BTU are used, taken from SAPP data.

- South Africa's Komati B site, decision variable "PGNSCexp(ty, "NSA",3)" consisting of four 110 MW units, will have a step size "NSCexpstep("NSA",3)" of 110 MW, "PGNSCmax("NSA",3)" equal to 440 MW, and a re-commissioning cost "NSCexpcost("NSA",3)" of $.542 million/MW. A heat rate of 12,876 BTU/KWh, and a fuel cost of $.47/10^6 BTU are used taken from the SAPP data sheet.
- South Africa's Camden site, decision variable "PGNSCexp(ty, "NSA",4)" consisting of 8 sites of 190 MW each , will have a step size "NSCexpstep("NSA",4)" of 190 MW, "PGNSCmax("NSA",4)" of 1520 MW, and a re-commissioning cost of $.108 million/MW. A heat rate of 12,186 BTU/KWh and a fuel cost of $.48/10^6 BTU are used.
- South Africa's PB reactor site, decision variable "PGNSCexp(ty, "NSA",5)" consisting of 10 units of 100 MW each, will be treated in the model as a small coal unit, with a step size "PGNSCexpstep("NSA",5)" of 100 MW, "PGNSCmax("NSA",5)" of 1000 MW, and an expansion cost "NSCexpcost("NSA",5)" of $.844 million/MW. A heat rate of 7583 BTU/KWh, and a fuel cost of $.45/10^6 BTU are used.
- Zimbabwe's Hwange upgrade, decision variable "PGNSCexp(ty, "ZIM",1)" single unit of 84 MW, will have a step size "NSCexpstep("ZIM",1)" of 84 MW, "PGNSCmax("ZIM",1) of 84 MW, and a cost "NSCexpcost("ZIM",1)" of $1.547 million/MW. Default heat rates of 9800 BTU/KWh and fuel costs of $.40/10^6 BTU are used since none were provided by SAPP.
- Zimbabwe's Hwange 7 & 8, decision variable "PGNSCexp(ty, "ZIM",2)" two units of 300 MW each, will have a step size of "NSCexpstep("ZIM",2)" of 300 MW, with "PGNSCmax("ZIM",2)" set at 600 MW, and "NSCexpcost("ZIM",2)" at $.923 million/MW. A heat rate of 9574 BTU/KWh and a fuel cost of $.36/10^6 BTU are used, taken from the SAPP data sheet.
- Zimbabwe's Gokwe North project, decision variable "PGNSCexp(ty,ZIM,3)", 4 units of 300 MW each, will have a step size "NSCexpstep(ty,ZIM,3)" of 300 MW, "PGNSCmax(ty,ZIM,3)" of 1200 MW, and "NSCexpcost(ty,ZIM,3)" of .800 million/MW, a heat rate of 9248 BTU/KWh, and a fuel cost of $.33/10^6 BTU.

Large Coal Projects (one project)

- South Africa’s Lekwe site, with 6 units of 659 MW each, will be treated as a large coal site, with an initial step and expansion step size of 659 MW. Thus, “PGNLCinit(“NSA”,1)” and “NLCexpstep(“NSA”,1)” both will be 659 MW. “PGNLCmax(“NSA”,1)” will be 3295 MW, since the initial step is not counted as expansion. The initial site construction variable, “YLC(tya,”NSA”,1)” will always be binary; the expansion variable “PGNLCexp(ty, “NSA”,1)” will always be integer.

Since the data furnished by SAPP does not distinguish between the initial and subsequent expansions, it will be assumed that the first step’s cost - “FGLC(“NSA”,1)” - will be 20% higher than the $1.027 million/MW given in the SAPP data, or $1.23 million. This means “FGLC(“NSA”,1)” is (659)(1.23) = $810 million. The remaining 5 units would then cost $.857 million/MW to arrive at the same total cost of $4.056 billion dollars given in the SAPP data for the entire 4056 MW.

Heat rates of 9890 BTU/KWh and fuel costs of $\$.41/10^6$ BTU given in the SAPP table will be used.

Combined Cycle Projects (one project)

- Namibia’s Kudu site is a single unit combined cycle plant of 750 MW with no plans for expansion. Thus, “PGNCCinit(“NAM”,1)” is 750 MW, and “PGNCCmax(“NAM”,1)” is zero (no expansion possible). The decision variable “YCC(ty, “NAM”,1)” is binary, and no replications are allowed - e.g.

$$\sum_{\tau=1}^{T} \mathrm{YCC}(\tau, \mathrm{NAM}, 1) \le 1$$

(This constraint needs to be added)

The fixed cost “FGCC(“NAM”,1)” is 650 million.

Default values of 7490 BTU/KWh for the heat rate and $\$1.10/10^6$ BTU for gas fuel cost are used in the absence of specific data.

<u>Gas Turbine Units</u> (3 projects)

The list of SAPP approved optional projects includes 3 gas turbine projects:

- South Africa proposes to add 4 large gas turbines of 250 MW each. The step size "NTexpstep("SA",1)" will be 250 MW, the maximum expansion "PGNTmax("SA",1)" will be 1000 MW, and the expansion cost "NTexpcost("SA",1)" will be $.324 million/MW, as reported in the SAPP table. Heat rates of 9478 BTU/KWh and fuel costs of $6.19/10^6 BTU (!) will be used, as reported in the SAPP tables.
- Tanzania's Ubungo site, consisting of one 40 MW gas turbine. The step size "NTexpstep("TAN",1)" and the maximum expansion "PGNTmax("TAN",1)" are both 40 MW; "NTexpcost("TAN",1)" is $.600 million. A heat rate of 9045 BTU/KWh and a fuel cost of $2.83/10^6 BTU will be used.
- Tanzania's Tegeta site, consisting of 10 units of 10 MW each. The step size "NTexpstep("TAN",2)" would be 10 MW, and "PGNTmax("TAN",2)" would be 100 MW. "NTexpcost("TAN",2)" is $.900 million/MW. A heat rate of 11055 BTU/KWh, and a fuel cost of $12.66/10^6 BTU (!), taken from the SAPP table, will be used.

4.2.7 New Hydro Capacity Constraints

As in the case of thermal plants, while existing hydro plants economically can increase their capacity up to some limit, new plants at a site must pay the fixed cost of site preparation and construction - usually a much larger investment than thermal units, since it involves dam construction - before any expansion can take place. Countries with sufficient hydro site capacity are allowed to construct hydro facilities - ANG, LES, MWI, NMZ, NAM, TAZ, DRC, ZAM, ZIM. The model notation for production from new hydro facilities at site "nh" is "Hnew(ty,ts,td,th,z,nh)"; the initial capacity parameters for plants at site "nh", Table "HNinit(z,nh)", are in the appendix, as is Table "HNVmax(z,nh)" the maximum possible additional capacity which can be installed at a site. The decision variable "HNVexp(ty,z,nh)", which indicates MW expansion in year "ty", can be either an integer, or a continuous variable; step size is given in Table "HNexpstep(z,nh)".

The only difference between the old and new hydro constraints is the inclusion of the binary decision variable “Yh(ty,z,nh)” in the capacity constraints; as before, “Yh(ty,z,nh)” = 1 if a plant is built in “ty”, 0 otherwise, except “Yh(“yr1”,z,nh)” = 0. Since preventive maintenance is assumed to take place when the reservoir is below minimum levels for generation, capacity is derated only by the forced outage rate “FORnh(z,nh)” given in the appendix. Thus, letting “DecayHN” be the aging factor, the new hydro capacity constraints are;

$$\mathrm{Hnew}(ty,ts,td,th,z,nh) \le \Bigg[\mathrm{HNinit}(z,nh) \sum_{tye=1}^{ty} \mathrm{Yh}(tye,z,nh)(1-\mathrm{DecayHN})^{n(ty-tye)}$$

$$+ \sum_{tye=1}^{ty} \mathrm{HNV}\exp(tye,z,nh)\,\mathrm{HN}\exp\mathrm{step}(z,nh)(1-\mathrm{DecayNH})^{n(tye)} \Bigg] \big[1-\mathrm{FORNH}(z,nh)\big]$$

where “Yh(ty,z,nh)” = {0,1}, “HNVexp(ty,z,nh)” either integer or positive.
Further,

$$\sum_{tye=1}^{ty} \mathrm{HNexpstep}(z,nh)\mathrm{HNV}\exp(tye,z,nh) \le \sum_{tye=1}^{ty} \mathrm{Yh}(tye,z,nh)\mathrm{HNV}\max(z,nh)$$

The upper limit on capacity additions must be respected, and no expansion can take place unless the initial plant is built.

These constraints, in GAMS format, become equations “HNmw” and “HNmust”; (Main.gms file, section 9)

```
EQUATION HNmw; {New hydros MW capacity}
HNmw(ty,ts,td,th,z,nh) ..
Hnew(ty,ts,td,th,z,nh) =L=
 (sum(tye$(ord(tye) LE ord(ty)), HNinit(z,nh)*Yh(tye,z,nh)
                        *power((1-DecayHN),DW*(ord(ty)-ord(tye))))
+sum(tye$(ord(tye) LE ord(ty)), HNVexp(tye,z,nh)*HNexpstep(z,nh)
                        *power((1-DecayHN),DW*(ord(ty)-ord(tye)))))
                        * (1 - FORnh(z,nh));
Equation HNmust; {Enforce fixed cost in new hydros}
HNmust(ty,z,nh) ..
 sum(tye$(ord(tye) LE ord(ty)), HNVexp(ty,z,nh)*HNexpstep(z,nh)) =L=
 sum(tye$(ord(tye) LE ord(ty)), Yh(tye,z,nh))*HNVmax(z,nh);
```

Finally, as in case of existing dams, there is a limit on the amount of water per year which can be used for generation, and hence a limit on the total MWh per year which can be generated. Further the limit on KWh is 0 unless the dam is built - hence;

CASE A - Run of River

$$\sum_{td,th} Hnew(ty, ts, td, th, z, nh) \leq HRNmwh(z, nh) \sum_{tye=1}^{ty} Yh(tye, z, nh) fdrought(ty)$$

for summer and winter separately

CASE B - Dams

$$\sum_{ts,td,th} Hnew(ty, ts, td, th, z, nh) \leq HDNmwh(z, nh) \sum_{tye=1}^{ty} Yh(tye, z, ih) fdrought(ty)$$

for the year where “HDNmwh(z,nh)” and “HRNmwh(z,nh)” are tabled in the appendix, and “fdrought(ty)” is user specified to reflect drought conditions in year “ty”. As in the case of old dams, adding capacity is assumed to involve only adding water turbines, not increasing the storage capacity of the dams. Thus “HNVexp” does not enter into either of the above equations. Further, no decay is assumed in the ability of the structure to hold the design volume of water; therefore, no decay is entered in the right hand side of either Case A or Case B.

In the absence of actual energy (MWh) capacity of the hydro sites, the following method was used to estimate “HRN” and “HDN”. For run of river projects, the maximum energy available in a season is given by multiplying the site’s power (MW) capacity (“HNinit(z,ih)” for proposed new sites), by the total time (hours) in that season, “thT*tdT”. For a site having a dam, a further seasonal catchment factor “fdamN(z,ih,ts)” (in the appendix) is used to estimate how much water (energy) the dam receives in each season, recognizing the fact that more water comes in during the rainy summer season than the dry winter season. Therefore, the maximum energy available from a new dam is given by

$$HDNmwh(z,nh) = Hinit(z,ih)*thT*tdT*[fdamN(z,nh,summer) + fdamN(z,nh,winter)].$$

The values of “HRNmwh(z,nh)” and “HDNmwh(z,nh)” are given below in GAMS notation, in equation “MWhDam”: (No run of the river hydro sites are under consideration at this time.) In GAMS format; (Main.gms file, section 9)

Dams

```
EQUATION MWhDam; {Annual MWh capacity limit for Dams }
MWhDam(ty,z,nh) ..
sum((ts,td,th), Hnew(ty,ts,td,th,z,nh))=L=  fdrought(ty) *
HDNmwh(z,nh)*sum(tye$(ord(tye) LE ord(ty)), Yh(tye,z,nh));
```

Table 4.2 lists 19 optional new hydro projects, one for Angola (260 MW), four for DRC (4750 MW each), one for Lesotho (72 MW), four for Malawi (475 MW), one for Mozambique (2000 MW), one for Namibia (360 MW), three for Tanzania (580 MW), 3 for Zambia (1480 MW), and one for Zimbabwe (898 MW). The DRC options are expansions at one site, which must be undertaken sequentially, (1 before 2, 2 before 3, etc.); each must be adopted in full, or not at all - e.g. the decision variables are binary. No expansion is possible for these sites.

All other new hydro projects allow expansion following the initial construction of the reservoir and its initial capacity.

4.2.8 Old Transmission Lines

Figure 2.1 in Chapter 2 lists the transfer capabilities of the existing lines connecting SAPP member abilities.

Using the familiar notation applied to existing transmission lines, power flow on a directed old link, “PF(ty,ts,td,th,z,zp)” must, in year “ty”, be less than or equal to existing capacity, “PFOinit(z,zp)” (tabled in the appendix) plus any expansion up to year “ty”, derated by the forced outage rate for transmission FORICO(z,zp) (tabled in the appendix), and adjusted for decay using “DecayPFO”. (Unforced outages in Transmission are considered insignificant.) Letting “PFOVexp(ty,z,zp)” be the continuous variable indicating the MW transmission capacity expanded in year “ty”, we have;

$$\mathrm{PF}(\mathrm{ty},\mathrm{st},\mathrm{td},\mathrm{th},\mathrm{z},\mathrm{zp}) \le \Bigg[\mathrm{PFOinit}(\mathrm{z},\mathrm{zp})(1-\mathrm{DecayPFO})^{\mathrm{nty}}$$

$$+\sum_{\mathrm{tye}=1}^{\mathrm{ty}} \mathrm{PFOV}\exp(\mathrm{tye},\mathrm{z},\mathrm{zp})(1-\mathrm{DecayPFO})^{\mathrm{n}(\mathrm{ty}-\mathrm{tye})}\Bigg](1-\mathrm{FORICO}(\mathrm{z},\mathrm{zp}))$$

$$\text{where } \mathrm{PFOV}\exp(\text{"yr1"},\mathrm{z},\mathrm{zp}) = 0,\ \mathrm{PFOV}\exp(\mathrm{ty},\mathrm{z},\mathrm{zp}) \ge 0$$

or, in GAMS notation, equation “PFOmw” is; (Main.gms file, section 12)

```
EQUATION PFOmw; {Old interconnectors MW capacity Limit}
PFOmw(ty,ts,td,th,z,zp) ..
 PF(ty,ts,td,th,z,zp) =L= (PFOinit(z,zp)
                              *power((1-DecayPFO),DW*ord(ty))
+ sum(tye$(ord(tye) LE ord(ty)), PFOVexp(tye,z,zp)
              *power((1-DecayPFO),DW*(ord(ty)-ord(tye)))))
                              *(1-FORICO(z,zp));
```

(Note the assumption that transmission capacity can only be added continuously)

Also, the upper limit on capacity expansion on existing lines, given in Table “PFOVmax(z,zp)” (in the appendix), must be respected. In GAMS format, equation “PFOlimit” is; (Main.gms file, section 12)

```
EQUATION PFOlimit; {Old interconnectors maximum additional Capacity limit}
PFOlimit(z,zp) ..
sum(ty, PFOVexp(ty,z,zp)) =L= PFOVmax(z,zp);
```

Since expansion in the {“z,zp”} direction also expands capacity in the {“zp,z”} direction, for AC lines, equation “PFOdirect” requires that; (Main.gms file, section 13) for AC lines,

```
EQUATION PFOdirect; {enforce expansion in other direction}
PFOdirect(ty,zp,z)$(not(((ord(zp) eq 5 ) and (ord(z) eq 8 ))
          or ((ord(zp) eq 8 ) and (ord(z) eq 5 ))
          or ((ord(zp) eq 12) and (ord(z) eq 13))
          or ((ord(zp) eq 13) and (ord(z) eq 12))
          or ((ord(zp) eq 12) and (ord(z) eq 1 ))
          or ((ord(zp) eq 1 ) and (ord(z) eq 12))
          or ((ord(zp) eq 1 ) and (ord(z) eq 7 ))
          or ((ord(zp) eq 7 ) and (ord(z) eq 1 ))))..
 PFOVexp(ty,zp,z) =E= PFOVexp(ty,z,zp);
```

The equation does not hold for DC lines.

4.2.9 New Transmission Lines

Figure 2.2 in Chapter 2 lists the possible augmentations to current transmission capacity now being considered by SAPP members.

The only change required for new lines is to add the binary variable, "Ypf(ty,z,zp)", to the capacity constraint to insure that flow will not take place without the full initial line being built -e.g.

$$\mathrm{PFnew}(ty, ts, td, th, z, zp) \le \Bigg[(\mathrm{PFNinit}(z, zp) \sum_{tya=1}^{ty} \mathrm{Ypf}(tya, z, zp)(1 - \mathrm{DecayPFN})^{n(ty-tya)}$$

$$+ \sum_{tya=1}^{ty} \mathrm{PFNVexp}(tya, z, zp))(1 - \mathrm{DecayPFN})^{n(ty-tya)} \Bigg] (1 - \overline{\mathrm{FORICN}(z, zp)}),$$

$$\text{where } \mathrm{Ypf}(ty, z, zp) = \{0, 1\},\ \ \mathrm{PFNVexp}(ty, z, zp) \ge 0.$$

In addition to expanding the capacity of existing connections, eight new transmission lines are currently allowed in the model; ANG/NAM, ANG/DRC, MWI/NMZ, MWI/ZAM, NMOZ/SMZ, SSA/NSA, ZAM/TAZ, and DRC/ZAM, with initial capacities tabled in "PFNinit(z,zp)" and forced outages in "FORICN(z,zp)" (tabled in the appendix). Others can easily be added simply by entering the cost capacity and cost data in the appropriate tables. Further, it is required that total expansion respect the upper limit on expansion "PFNVmax(z,zp)", and that expansion can take place only after initial construction;

$$\sum_{tya=1}^{ty} \mathrm{PFNV\,exp}(tya, z, zp) \le \mathrm{PFNV\,max}(z, zp) \sum_{tya=1}^{ty} \mathrm{Ypf}(tya, z, zp)$$

where "PFNVmax(z,zp)" is in the appendix, and "Ypf("yr1",z,zp)" = 0.

The GAMS format for: (a) the capacity constraint, equation "PFNmw"; (b) the requirement that expansion take place after initial construction, while at the same time insuring that expansion does not exceed the upper limit, equation "PFNmust"; and (c) the requirement that expansion/construction in one direction also means similar expansion construction in the other direction, equations "PFNdirect" and "Ypfdirect", follows. (Main.gms file, section 11 and 12)

(a)
```
EQUATION PFNmw; {New interconnectors MW capacity Limit}
PFNmw(ty,ts,td,th,z,zp) ..
PFnew(ty,ts,td,th,z,zp) =L=
(sum(tye$(ord(tye) LE ord(ty)), PFNinit(z,zp)*Ypf(tye,z,zp)
             *power((1-DecayPFN),DW*(ord(ty)-ord(tye))))
+sum(tye$(ord(tye) LE ord(ty)), PFNVexp(tye,z,zp)
             *power((1-DecayPFN),DW*(ord(ty)-ord(tye)))))
             *(1-FORICN(z,zp)) ;
```

(b)
```
Equation PFNmust; {Incur fixed cost before doing any expansion}
PFNmust(ty,z,zp) ..
sum(tye, PFNVexp(ty,z,zp)) =L= sum(tye$(ord(tye) LE ord(ty)),
                Ypf(tye,z,zp))*PFNVmax(z,zp);
```

(c)
```
EQUATION PFNdirect; {enforce expansion in "zp,z" direction}
PFNdirect(ty,zp,z) ..
 PFNVexp(ty,zp,z) =E= PFNVexp(ty,z,zp);

EQUATION Ypfdirect; {enforce construction in "z,zp" direction}
Ypfdirect(ty,zp,z) ..
Ypf(ty,zp,z) =E= Ypf(ty,z,zp);


Equation PF_one;
PF_one(z,zp) .. sum(ty, YPF(ty,z,zp)) =L= 1;
```

Finally the appendix contains Table "PFfix(z,zp)" which sets the fixed level of trade between countries at the 1997 peak levels; this is used to calculate the SAPP system cost of each SAPP member building domestic capacity to satisfy growth in domestic consumption, which is the only option with trade fixed at 1997 levels. It is to be compared with the system cost where imports/exports are free to find the level which minimizes total SAPP system cost. (Lines.inc file, section 6)

Table 4.3 PFfix(z,zp) fixtrade between region z and zp (MWh per day)
* Data from short-run model provided by Dr. Sparrow on June12th, 98

	Ang	Bot	Mwi	Les	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim	
Ang	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Bot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Les	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Mwi		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nmz		0	0	0	0	0	0	0	21600	0	0	0	0	0	10320
Smz	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Nam		0	0	0	0	0	0	0	0	1E4	0	0	0	0	0
NSA		0	1800	0	1296	0	1536	2880	0	1E9	1800	0	0	0	3600
SSA		0	0	0	0	0	0	1E4	1E9	0	0	0	0	0	0
Swz	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Taz	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
DRC		0	0	0	0	0	0	0	0	0	0	0	0	2400	0
Zam		0	0	0	0	0	0	0	0	0	0	0	0	0	2400
Zim	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

4.2.10 Pumped Storage Capacity Constraints

As in the case of hydroelectric dams, two types of capacity constraints are needed - one for the maximum instantaneous rate at which water can flow out of the reservoir, and the other for the limit on the total amount of water which can be withdrawn over a period. The first is controlled by the size of the generating and pumping unit, the second by the volume of the reservoir.

Considering the maximum instantaneous amount of electricity which can be generated, if the parameters "PGPSOinit(z)", "PSOexpstep(z)", and "PSOmax(z)" are the initial MW capacity, the size MW increment, and the maximum capacity respectively for existing generating/pumping equipment, and if "PSOexp(ty,z)" is the decision variable for capacity expansion - either positive or integer - and if "DecayPHO" is the percent decay parameter for pumped units, the MW generating capacity constraint for existing pumped storage can be written;

$$\mathrm{PGPSO}(ty, ts, td, th, z) \le \mathrm{PGPSOinit}(z)(1 - \mathrm{DecayPHO})^{nty} +$$

$$\sum_{\tau=1}^{ty} \mathrm{PSOexpstep}(z)\mathrm{PSOexp}(\tau, z)(1 - \mathrm{DecayPHO})^{n(ty-\tau)}$$

and the constraint that no more than the maximum amount can be added at a site:

$$\sum_{\tau=1}^{T} \mathrm{PSOexpstep}(z)\mathrm{PSOexp}(t, z) \le \mathrm{PSOmax}(z)$$

The requirement that no more than the available volume of water in the reservoir can be used for power generation over any 24 hour period can be expressed as;

$$\sum_{\tau=1}^{24} \mathrm{PGPSO}(\mathrm{ty}, \mathrm{ts}, \mathrm{td}, \tau, \mathrm{z}, \mathrm{n}) \leq \mathrm{HDPSOmwh}(\mathrm{z})$$

where "HDPSOmwh(z)" is the mwh equivalent of the maximum volume of water available for generation in the existing reservoir over a 24 hour period. The default value is set at 24 times the instantaneous generation capacity of 1400 MW, or 33,600 MWh.

The current version of the model assumes no additions are possible at the current pumped storage site in RSA - e.g., "PSOmax(z)" = 0, and "PSOexp(ty,z)". Thus pumped storage is limited to 1400 MW, the present capacity. Hence, in GAMS format, equations "PHOmw" and "PHOcap" are; (Main.gms file, section 25)

```
Equation PHOmw;
PHOmw(ty,ts,td,th,z)$PGPSOinit(z)..
          PGPSO(ty,ts,td,th,z)
 =L=  PGPSOinit(z)*power((1-DecayPHO),DW*(ord(ty)));

Equation PHOcap;{Existing PS hydro reservoir volume (MWh) Capacity constraint}
PHOcap(ty,ts,td,z)$PGPSOinit(z)..
sum(th, PGPSO(ty,ts,td,th,z)* Mtod(th) ) =L=  HDPSOmwh(z);
```

The only difference between new and old pumped storage sites is the addition of a binary variable "Yph(ty,z,phn)" for each of the four possible sites, listed in Table 4.2, preparation and installation of additional capacity, and the substitution of "N" for "O" in the notation, the maximum MW capacity constraint is;

$$\mathrm{PGPSN}(ty, ts, td, th, z, phn) \le \mathrm{PHNinit}(z, phn) \sum_{\tau=1}^{ty} \mathrm{Yph}(\tau, z, phn)(1 - \mathrm{DecayPhn})^{n(ty-\tau)}$$

$$+ \sum_{\tau=1}^{ty} \mathrm{PSNexpstep}(z, phn)\mathrm{PSN\,exp}(\tau, z, phn)(1 - \mathrm{DecayPhn})^{n(ty-\tau)}$$

and a constraint that prevents the cheaper additions from being added without the more expensive site preparation, and also limits expansion to its upper limit, once the initial site expanse is complete;

$$\sum_{\tau=1}^{T} \mathrm{PSNexpstep}(z, phn)\mathrm{PSN\,exp}(\tau, z, phn) \le \mathrm{PSN\,max}(z, phn)\mathrm{Yph}(ty, z, phn)$$

The maximum reservoir volume constraint, expressed in KWh, can be written;

$$\sum_{\tau=1}^{24} \mathrm{PGPSN}(ty, ts, td, \tau, z, phn) \le \mathrm{HDPSNmwh}(z, phn) \sum_{\tau=1}^{ty} \mathrm{Yph}(\tau, z, phn)$$

The current model allows construction of new pumped storage at four sites in RSA, but no expansion - e.g. “PSNmax(z,phn)” = 0 for all “phn” = 1, 2, 3, 4, and hence “PSNecp(ty,z,phn)” = 0 for all “ty”. Hence, in GAMS format, equations “PHNmw” and “PHN_one” are; (Main.gms file, section 25)

```
EQUATION PHNmw; {New pumped hydros MW capacity}
PHNmw(ty,ts,td,th,z,phn) $PHNinit(z,phn) ..
PGPSN(ty,ts,td,th,z,phn) =L=
 sum(tye$(ord(tye) LE ord(ty)), PHNinit(z,phn)*Yph(tye,z,phn)
                    *power((1-DecayPHN),DW*(ord(ty)-ord(tye))));

Equation PHN_one; {only one pumped hydro per site}
PHN_one(z,phn)$PHNinit(z,phn) .. sum(ty, Yph(ty,z,phn) ) =L= 1;

Equation PHNcap;{New PS hydro reservoir volume (MWh) Capacity consrtaint}
PHNcap(ty,ts,td,z,phn)$PHNinit(z,phn) ..
sum(th, PGPSN(ty,ts,td,th,z,phn)* Mtod(th) ) =L=  HDPSNmwh(z,phn);
```

4.3 The Reliability Constraints

Reliability requirements enter the model in two ways:

Requirement #1:

Each country must maintain a SAPP specified reserve margin for each of the major sources of supply - thermal plants, including pumped storage, (Parameter "RESTHM" in the appendix - default value 19%) and hydro plants (Parameter "RESHYD" - 10% default value). The model also allows imports and exports during peak periods to enter the reserve calculation, with a specified reserve margin for each (Parameters "RESIMP" and "RESEXP" - 25% default for each - but the values can be set by the user). Which level of imports and exports to enter is an important issue. Clearly, a proxy for firm imports and exports during peak periods is needed. Unfortunately, the model does not distinguish between firm and interruptable power, only when the power is dispatched: hence, the choices are peak, average, or off-peak exports/imports. Since the model is clairvoyant, (no uncertainty) there is no need for interruptable sales/purchases; all transactions can be thought of as firm. Hence, peak imports and exports were chosen. The constraint, then is of the form:

For each "z" and each year "ty":

$$\frac{\text{Available Installed Thermal Capacity}}{1+\text{RESTHM(z)}} + \frac{\text{Available Installed Hydro Capacity}}{1+\text{RESHYD(z)}} + \frac{\text{Imports at Peak}}{1+\text{RESIMP(z)}}$$

$$-\frac{\text{Exports at Peak}}{1+\text{RESEXP(z)}} \geq \left[\text{PeakD(ty, z)} * \text{dgr(z, ty)} - \text{LM(z)}\right]\left[\text{DLC(z)}\right]$$

Note that the choice of "RESTHM", "RESHYD", "RESIMP", and "RESEXP" are behavioral choices; values can be entered to reflect each SAPP member's attitudes. For instance, if a SAPP member believes their available generating capacity should be increased to take into account imports adjusted for expected flow reductions caused by transmission line and source country generation outages, but should be increased to cover only exports at peak without taking into account similar possible interruptions, that can easily be done by setting "RESEXP(z)" to equal 0, and "RESIMP(z)" > 0.

The full equation is as follows;

$$
\frac{\left[\begin{array}{l}
\mathrm{PGOinit}(\cdot)(1-\mathrm{DecayPGO})^{\mathrm{nty}} + \mathrm{PGO\,expstep}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{PGO\,exp}(\tau,z,i)(1-\mathrm{DecayPGO})^{n(\mathrm{ty}-\tau)} \\
+ \\
\mathrm{NTexstep}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{PGNT\,exp}(\tau,z,i)(1-\mathrm{DecayNT})^{n(\mathrm{ty}-\tau)} \\
\quad + \mathrm{NSC\,expstep}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{PGNSC\,exp}(\tau,z,ni)(1-\mathrm{DecayNSC})^{n(\mathrm{ty}-\tau)} \\
+ \\
\mathrm{PGNCCinit}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{YCC}(\tau,z,ni)(1-\mathrm{DecayNCC})^{n(\mathrm{ty}-\tau)} \\
\quad + \mathrm{NCC\,expstep}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{PGNCC\,exp}(\tau,zi,ni)(1-\mathrm{DecayNCC})^{n(\mathrm{ty}-\tau)} \\
+ \\
\mathrm{PGNLCinit}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{YLC}(\tau,z,ni)(1-\mathrm{DecayNLC})^{n(\mathrm{ty}-\tau)} \\
\quad + \mathrm{NLC\,expstep}(\cdot)\sum_{\mathrm{ty}=1}^{\mathrm{ty}} \mathrm{PGNLC\,exp}(\tau,z,ni)(1-\mathrm{DecayNLC})^{n(\mathrm{ty}-\tau)}
\end{array}\right]}{1+\mathrm{RESTHM}(z)}
$$

$$
+
$$

$$
\frac{\left[\begin{array}{l}
+\mathrm{HOinit}(\cdot)(1-\mathrm{DecayHO})^{\mathrm{nty}} + \mathrm{HOV\,expstep}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{HOV\,exp}(\tau,z,ih)(1-\mathrm{DecayHO})^{n(\mathrm{ty}-\tau)} \\
+\mathrm{HNinit}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{Yh}(\tau,z,nh)(1-\mathrm{DecayHN})^{n(\mathrm{ty}-\tau)} \\
\quad + \mathrm{HN\,expstep}(\cdot)\sum_{\tau=1}^{\mathrm{ty}} \mathrm{HNV\,exp}(\tau,z,nh)(1-\mathrm{DecayHN})^{n(\mathrm{ty}-\tau)} \\
+\mathrm{PGPSOinit}(z)(1-\mathrm{DecayPHO})^{\mathrm{nty}} \\
\quad + \sum_{\mathrm{phn}}\sum_{\tau=1}^{\mathrm{ty}} \left[\mathrm{PHNinit}(z,\mathrm{phn})\mathrm{Yph}(\tau,z,\mathrm{phn})\right]\left[1-\mathrm{DecayPHN}\right]^{n(\mathrm{ty}-\tau)}
\end{array}\right]}{1+\mathrm{RESHYD}(z)}
$$

$$
+
$$

$$
\frac{\sum_{\mathrm{zp}} \mathrm{PF}(\mathrm{ty},\mathrm{ts},\mathrm{td},\text{"peak"},\mathrm{zp},z)(1-\mathrm{PFOloss}(z,\mathrm{zp})}{1+\mathrm{RESIMP}(z)} - \sum_{\mathrm{zp}} \frac{\mathrm{PF}(\mathrm{ty},\mathrm{ts},\mathrm{td},\text{"peak"},z,\mathrm{zp})}{1+\mathrm{RESEXP}(z)}
$$

$$
\geq \left[\mathrm{PeakD}(\mathrm{ty},z)\mathrm{dgr}(z,\mathrm{ty}) - \mathrm{LM}(z,\mathrm{th})\right]\left[\mathrm{DLC}(z)\right]
$$

The net import term is summed over both old and new lines. As we have argued elsewhere, not to allow net imports to enter into the reliability constraints will destroy the benefits of buying, rather than making, forcing imports to compete against the out of pocket costs of domestic generation.

This reserve margin constraint, as stated in GAMS notation, is equation “ResvREG2”; (Main.gms file, section 14)

```
EQUATION ResvREG2;
ResvREG2(ty,z)$(ord(ty) NE 1) ..
 (sum(i$(PGOinit(z,i) GT 1),
      PGOinit(z,i)*power((1-DecayPGO),DW*ord(ty))
    + sum(tyb$(ord(tyb) LE ord(ty)), PGOexp(tyb,z,i)*PGOexpstep(z,i)
                    *power((1-DecayPGO),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNT(z,ni) GT 0),
     sum(tyb$(ord(tyb) LE ord(ty)),PGNTexp(tyb,z,ni)*NTexpstep(z,ni)
                    *power((1-DecayNT),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNCC(z,ni) GT 0),
     sum(tya$(ord(tya) LE ord(ty)),PGNCCinit(z,ni)*YCC(tya,z,ni)
                    *power((1-DecayNCC),DW*(ord(ty)-ord(tya))))
   + sum(tyb$(ord(tyb) LE ord(ty)),PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)
                    *power((1-DecayNCC),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNSC(z,ni) GT 0),
     sum(tyb$(ord(tyb) LE ord(ty)),PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)
                    *power((1-DecayNSC),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNLC(z,ni) GT 0),
     sum(tya$(ord(tya) LE ord(ty)),PGNLCinit(z,ni)*YLC(tya,z,ni)
                   *power((1-DecayNLC),DW*(ord(ty)-ord(tya))))
   + sum(tyb$(ord(tyb) LE ord(ty)),PGNLCexp(tyb,z,ni)* NLCexpstep(z,ni)
  *power((1-DecayNLC),DW*(ord(ty)-ord(tyb))))
   )) / (1 + resthm(z))
+(sum(ih, HOinit(z,ih)*power((1-DecayHO),DW*ord(ty))
     + sum(tye$(ord(tye) LE ord(ty)), HOVexp(tye,z,ih)*HOexpstep(z,ih)
                    *power((1-DecayHO),DW*(ord(ty)-ord(tye))))
   )
+sum(nh, sum(tye$(ord(tye) LE ord(ty)),HNinit(z,nh)*Yh(tye,z,nh)
                    *power((1-DecayHN),DW*(ord(ty)-ord(tye))))
           +sum(tye$(ord(tye) LE ord(ty)), HNVexp(tye,z,nh)*HNexpstep(z,nh)
                    *power((1-DecayHN),DW*(ord(ty)-ord(tye))))
   ) + PGPSOinit(z)*power((1-DecayPHO),DW*(ord(ty)))

+ sum(phn, sum(tye$(ord(tye) LE ord(ty)), PHNinit(z,phn)*Yph(tye,z,phn)
                  *power((1-DecayPHN),DW*(ord(ty)-ord(tye)))))
                  / (1 + reshyd(z))

+sum((ts,td,zp,th)$(PFOinit(zp,z) GT 9 AND july2400(ts,td,th,z) EQ PeakD('yr2',z)),
            (PF(ty,'winter','peak',th,zp,z)*(1-PFOloss(zp,z))) / (1 + resimp(z))
           -(PF(ty,'winter','peak',th,z,zp)) / (1 + resexp(z))  )
```

```
+sum((ts,td,zp,th)$(PFNinit(zp,z) GT 9 AND july2400(ts,td,th,z) EQ PeakD('yr2',z)),
            (PFnew(ty,'winter','peak',th,zp,z)*(1-PFNloss(zp,z))) / (1 + resimp(z))
           -PFnew(ty,'winter','peak',th,z,zp)) / (1 + resexp(z))


=G= (DLC(z) * (PeakD(ty,z) * dgr(z,ty) - sum(th, (LM(z,th)))));
```

<u>Requirement #2:</u>

Installed capacity, unadjusted for any reserve margin, must exceed peak demand in each country by the MW value of the largest single plant installed or envisioned in each country - e.g. “MAXG(z)” (tabled in the appendix);

$$\text{Available Installed Thermal, Hydro, and Net Peak Imports} \geq$$
$$\left[\mathrm{PeakD}(ty,z) * \mathrm{dgr}(z,ty) - \mathrm{LM}(z,th)\right]\left[\mathrm{DLC}(z)\right] + \mathrm{MaxG}(z)$$

The GAMS format statement of this requirement is, equation “ResvREG3”; (Main.gms file, section 15)

```
EQUATION ResvREG3;
ResvREG3(ty,z)$(ord(ty) ne 1)..
 sum(i$(PGOinit(z,i) GT 1),
       PGOinit(z,i)*power((1-DecayPGO),DW*ord(ty))
     + sum(tyb$(ord(tyb) LE ord(ty)), PGOexp(tyb,z,i)*PGOexpstep(z,i)
                    *power((1-DecayPGO),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNT(z,ni) GT 0),
      sum(tyb$(ord(tyb) LE ord(ty)),PGNTexp(tyb,z,ni)*NTexpstep(z,ni)
                    *power((1-DecayNT),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNCC(z,ni) GT 0),
      sum(tya$(ord(tya) LE ord(ty)),PGNCCinit(z,ni)*YCC(tya,z,ni)
                    *power((1-DecayNCC),DW*(ord(ty)-ord(tya))))
    + sum(tyb$(ord(tyb) LE ord(ty)),PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)
                    *power((1-DecayNCC),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNSC(z,ni) GT 0),
      sum(tyb$(ord(tyb) LE ord(ty)),PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)
                    *power((1-DecayNSC),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNLC(z,ni) GT 0),
      sum(tya$(ord(tya) LE ord(ty)),PGNLCinit(z,ni)*YLC(tya,z,ni)
                   *power((1-DecayNLC),DW*(ord(ty)-ord(tya))))
    + sum(tyb$(ord(tyb) LE ord(ty)),PGNLCexp(tyb,z,ni)* NLCexpstep(z,ni)
                    *power((1-DecayNLC),DW*(ord(ty)-ord(tyb))))
   )
+sum(ih, HOinit(z,ih)*power((1-DecayHO),DW*ord(ty))
      + sum(tye$(ord(tye) LE ord(ty)), HOVexp(tye,z,ih)*HOexpstep(z,ih)
                     *power((1-DecayHO),DW*(ord(ty)-ord(tye))))
   )
```

```
+sum(nh, sum(tye$(ord(tye) LE ord(ty)),HNinit(z,nh)*Yh(tye,z,nh)
                    *power((1-DecayHN),DW*(ord(ty)-ord(tye))))
         +sum(tye$(ord(tye) LE ord(ty)), HNVexp(tye,z,nh)*HNexpstep(z,nh)
                    *power((1-DecayHN),DW*(ord(ty)-ord(tye))))
   )
+ PGPSOinit(z)*power((1-DecayPHO),DW*(ord(ty)))

+ sum(phn, sum(tye$(ord(tye) LE ord(ty)), PHNinit(z,phn)*Yph(tye,z,phn)
                  *power((1-DecayPHN),DW*(ord(ty)-ord(tye)))))

+sum((ts,td,zp,th)$(PFOinit(zp,z) GT 9 AND july2400(ts,td,th,z) EQ PeakD('yr2',z)),
          PF(ty,'winter','peak',th,zp,z)*(1-PFOloss(zp,z))
         -PF(ty,'winter','peak',th,z,zp)  )
+sum((ts,td,zp,th)$(PFNinit(zp,z) GT 9 AND july2400(ts,td,th,z) EQ PeakD('yr2',z)),
          PFnew(ty,'winter','peak',th,zp,z)*(1-PFNloss(zp,z))
         -PFnew(ty,'winter','peak',th,z,zp)  )

=G= DLC(z) * (PeakD(ty,z) * dgr(z,ty) - sum(th, (LM(z,th)))) + maxG(z);
```

4.3.1 The Autonomy Constraint

In addition to SAPP requiring each country to maintain adequate reserves, discounting net imports as each feels necessary, by use of the net import reserve margin (a choice of ∞ removes net imports from consideration), each country may require that domestic production capability (not involving any net imports) always be large enough to satisfy a given fraction of domestic demand. This autonomy factor, Table “AF(z,ty)” in the appendix, gives the nominal values assigned to each country. They can be altered by simply changing the values in the table. Thus, the form of the autonomy constraint is;

$$\text{Domestic Capacity(ty)} \geq \text{AF(z, ty)PeakD(ty, z)dgr(z, ty)DLC(z) - LM(z)}$$

or, in GAMS notation, equation “ResvREG4” is; (Main.gms file, section 16)

```
EQUATION ResvREG4;  {For all but SSA and NSA}
ResvREG4(ty,z)$(ord(ty) ne 1 and (ord(z) ne 8) and (ord(z) ne 9)) ..
 sum(i$(PGOinit(z,i) GT 1),
      PGOinit(z,i)*power((1-DecayPGO),DW*ord(ty))
    + sum(tyb$(ord(tyb) LE ord(ty)), PGOexp(tyb,z,i)*PGOexpstep(z,i)
                   *power((1-DecayPGO),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNT(z,ni) GT 0),
     sum(tyb$(ord(tyb) LE ord(ty)),PGNTexp(tyb,z,ni)*NTexpstep(z,ni)
                   *power((1-DecayNT),DW*(ord(ty)-ord(tyb))))
   )
+sum(ni$(fpNCC(z,ni) GT 0),
     sum(tya$(ord(tya) LE ord(ty)),PGNCCinit(z,ni)*YCC(tya,z,ni)
                   *power((1-DecayNCC),DW*(ord(ty)-ord(tya))))
```

```
     + sum(tyb$(ord(tyb) LE ord(ty)),PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)
                        *power((1-DecayNCC),DW*(ord(ty)-ord(tyb))))
   )
 +sum(ni$(fpNSC(z,ni) GT 0),
      sum(tyb$(ord(tyb) LE ord(ty)),PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)
                        *power((1-DecayNSC),DW*(ord(ty)-ord(tyb))))
   )
 +sum(ni$(fpNLC(z,ni) GT 0),
      sum(tya$(ord(tya) LE ord(ty)),PGNLCinit(z,ni)*YLC(tya,z,ni)
                       *power((1-DecayNLC),DW*(ord(ty)-ord(tya))))
     + sum(tyb$(ord(tyb) LE ord(ty)),PGNLCexp(tyb,z,ni)* NLCexpstep(z,ni)
                        *power((1-DecayNLC),DW*(ord(ty)-ord(tyb))))
   )
 +sum(ih, HOinit(z,ih)*power((1-DecayHO),DW*ord(ty))
      + sum(tye$(ord(tye) LE ord(ty)), HOVexp(tye,z,ih)*HOexpstep(z,ih)
                        *power((1-DecayHO),DW*(ord(ty)-ord(tye))))
   )
 +sum(nh, sum(tye$(ord(tye) LE ord(ty)),HNinit(z,nh)*Yh(tye,z,nh)
                        *power((1-DecayHN),DW*(ord(ty)-ord(tye))))
           +sum(tye$(ord(tye) LE ord(ty)), HNVexp(tye,z,nh)*HNexpstep(z,nh)
                        *power((1-DecayHN),DW*(ord(ty)-ord(tye))))
   )

 + PGPSOinit(z)*power((1-DecayPHO),DW*(ord(ty)))

 + sum(phn, sum(tye$(ord(tye) LE ord(ty)), PHNinit(z,phn)*Yph(tye,z,phn)
                       *power((1-DecayPHN),DW*(ord(ty)-ord(tye)))))

 =G= AF(z,ty) * PeakD(ty,z) * dgr(z,ty) * DLC(z);
```

The above equations hold for all regions, except NSA and SSA, which have a single summed constraint.

4.4 The Objective Function Module

The objective function in the full model is broken down into 4 parts:
I Fuel & Operating Costs, II Cost of Unserved Energy, III Capital Costs, and
IV The Budget Constraints..

4.4.1 Fuel and Operating Costs

A) <u>Thermal Units</u>

All thermal units operating costs are calculated in the same way. In a given year, “ty”, the costs for old (“PG”), new turbines (“NT”), new combined cycle (“CC”), new small coal (“SC”), and new large coal (“LC”) are of the generic form;

$$\sum_{ts,td,th,z} \sum_{i} \overbrace{PG(ty,ts,td,th,z,i)}^{\text{power generation}} \left[\overbrace{HR(z,i)}^{\text{heat rate}} \overbrace{fp(z,i)}^{\text{fuel cost}} \overbrace{fpesc(z,i)^{n(ty)-1}}^{\text{fuel escalation}} + \overbrace{OM(z,i)}^{\text{O\&M cost}} \right]$$

one each for each of the unit types, with appropriate modifications in notation made for each: since "PG(·)" is MWh, the costs are $/MWh.

"PG(·)", "PGNT(·)", "PGNCC(·)", "PGNSC(·)", and "PGNLC(·)" are as entered in the supply/demand module. "HR(z,i)", the heat rates for the thermal plants (BTU x 10^3/KWh) are given in Tables "HRO(z,i)", "HRNT(z,ni)", "HRNCC(z,ni)", "HRNLC(z,ni)", and "HRNSC(z,ni)" in the appendix to this section. Nominal values in the tables are taken from U.S. data, and can be altered by country "z" and site ("i,ni") by users.

Fuel costs for old plants - Table "fpo(z,i)" - and new plants - Tables "fpNT(z,ni)", "fpNCC(z,ni)", "fpNSC(z,ni)", and "fpNLC(z,ni)" in cents per 10,000 BTU are given in the appendix. Normal values in the tables reflect recent U.S. costs ($1.20 to $2.00/$10^6$ BTU for gas, $.30 to $.40/$10^6$ BTU for coal); these numbers can be changed in the tables by users to reflect each SAPP members' price expectations.

The fuel escalation rates "fpescO(z,i)", "fpescNT(z)", "fpescNCC(z)", "fpescNSC(z)", and "fpescNLC(z)" are also tabled in the appendix. A nominal value of 1% a year growth is in all tables; users can enter their own estimates.

The tables for "O&M" costs in $/MWh for the various options, "O&M(z,i)" for old plants and "O&M(z,ni)" for new, are found in the appendix; default values are based upon U.S. experience.

The parameter "n(ty)" in the appendix converts yearly fuel escalation rates into period growth rates, since periods contain multiple years.

Finally, within a given year, the proper weights for the seasons, days, and hours need to be entered into the objective function to insure that the fuel costs represent all 8,760 hours per year. The scalars "Mseason", "Mday(td)" and "Mtod(th)" (tabled in the appendix) provide the necessary scale up. (The objective function used assumes the 6 hour version of the demand is used; if the 24 hour version is used, no "Mtod(th)" scalars are needed.)

B) Hydro Units

The only operating cost is the cost of water "wcost", now set at \$3.5/MWh, which can be altered by changing scalar "wcost" in the appendix. These cover "O&M" and any opportunity cost of water. Hence, the operating costs for hydro are simply:

$$\sum_{ih} (wcost)H(ty, ts, td, th, z, ih) + \sum_{nh} (wcost)Hnew(ty, ts, td, th, z, nh)$$

Costs in year "ty" for thermal and hydro units are then summed and present valued, using the discount rate "disc". The GAMS statement of the fuel and operating costs over the horizon, present valued to "t"=0 by multiplying by $\frac{1}{(1+disc)^{ty-1}}$ is then, equation "objf"; (Main.gms file, section 27)

```
SUM((ty,ts,td,th,z), Mperiod(ty)*Mseason(ts)*Mday(td)*Mtod(th)*
   {fuel costs}  (  sum(i,  PG(ty,ts,td,th,z,i)*(HRO(z,i)*fpO(z,i)
                               *power(fpescO(z,i),(HA(ty)-1)) + OMO(z,i)) )
           +sum(ni, PGNT(ty,ts,td,th,z,ni)*(HRNT(z,ni)*fpNT(z,ni)
                               *power(fpescNT(z),(HA(ty)-1)) + OMT(z,ni)) )
                      +sum(ni, PGNCC(ty,ts,td,th,z,ni)*(HRNCC(z,ni)*fpNCC(z,ni)
                               *power(fpescNCC(z),(HA(ty)-1)) + OMCC(z,ni)) )
                      +sum(ni, PGNSC(ty,ts,td,th,z,ni)*(HRNSC(z,ni)*fpNSC(z,ni)
                               *power(fpescNSC(z),(HA(ty)-1)) + OMSC(z,ni)) )
                      +sum(ni, PGNLC(ty,ts,td,th,z,ni)*(HRNLC(z,ni)*fpNLC(z,ni)
                               *power(fpescNLC(z),(HA(ty)-1)) + OMLC(z,ni)) )
   {Cost of water} +sum(ih, wcost*H(ty,ts,td,th,z,ih)      )
                   +sum(nh, wcost*Hnew(ty,ts,td,th,z,nh)   )
   {UE costs}      +UEcost*UE(ty,ts,td,th,z)
            )/(1+disc)**(HA(ty)-1)
   )
```

4.4.2 Cost of Unserved Energy

This cost is the product of parameter "UEcost" (value in the appendix) times the variable "UE(ty,ts,td,th,z)". "UEcost" has a nominal value of \$5000/MWh, (a price actually paid in June 1998 during a U.S. power shortage!) users can specify their own values.

4.4.3 Capital Cost

Capital costs are broken down by equipment type:

- PGOcapcost(ty); capital costs in year "ty" associated with expansion of existing thermal sites, present valued to year 0,

- PGNcapcost(ty); present valued capital costs associated with constructing and expanding new thermal sites in year "ty",
- HOcapcost(ty); present valued capital costs associated with expansion of old hydro sites in "ty",
- HNcapcost(ty); present valued capital costs associated with constructing and expanding new hydro sites in "ty",
- PFOcapcost(ty); present valued capital costs associated with expanding old transmission lines in "ty",
- PFNcapcost(ty); present valued capital costs associated with constructing and expanding new transmission lines,in "ty",
- PSOcapcost(ty); present valued capital costs of expanding existing pumped storage sites,
- PSNcapcost(ty); capital cost of constructing and expanding new pumped storage facilities.

The capital costs for all years are simply the sum over all "ty" of the above: no additional present value is necessary - the dollars are already present valued.

A) Existing Sites/Lines

The generic form of the capital cost terms in year "ty" for expansion of existing sites and lines is relatively simple, involving as it does only expansion of existing capacity. The equation for all old thermal sites in year "ty", present valued to year 0, is simply;

$$\mathrm{PGOcapcost(ty)} =$$

$$\sum_{\mathrm{z,i}} \sum_{\mathrm{tyb=1}}^{\mathrm{ty}} \frac{\overbrace{\mathrm{PGOexp(tyb,z,i)PGOexpstep(z,i)Oexpcost(z,i)}}^{\text{total investment at "i" in tyb}}\,\mathrm{crfi(z,i)}}{(1+\mathrm{disc})^{\mathrm{ty-1}}}$$

"PGOexp(tyb,z,i)PGOexpstep(z,i)" is the MW amount of expansion that takes place in year "tyb", regardless of the choice of expansion modeling - fixed increment, or continuous. Multiplying the MW expansion by "Oexpcost(z,i)", the cost/MW of expansion, tabled in the appendix, yields the total capital investment made in year “tyb” at site “i”. Multiplying this total investment by the capital recovery factor “crfi(z,i)”, (tabled in the appendix), converts the total investment into the amount to be recovered annually until the end of the horizon, starting in year “tyb”.

Thus, in year “ty”, the annual charges in that year should be the sum of all annual charges arising as a result of investments made up to and including, year “ty”, e.g.

$$\sum_{tyb=1}^{ty} \mathrm{PGOexp}(tyb, z, i)\mathrm{PGOexpstep}(z, i)\mathrm{Oexpcost}(z, i)\mathrm{crfi}(z, i)$$

The present value of these at time = 0, summed over all “z” and “i”, is the equation “PGOcapcost(ty)”.

In similar fashion, old hydro capacity expansion capital costs are:

$$\mathrm{HOcapcost}(ty) = \sum_{z,ih} \sum_{tyb=1}^{ty} \frac{\mathrm{HOVexp}(tyb,z,ih)\mathrm{HOVexpstep}(z,ih)\mathrm{HOVcost}(z,ih)\mathrm{crfih}(z,ih)}{(1+\mathrm{disc})^{ty-1}}$$

and the expression for capital costs for existing transmission line expansion are;

$$\mathrm{PFOcapcost}(ty) = \sum_{z,zp} \sum_{tye=1}^{ty} \frac{\mathrm{PFOVexp}(tye, z, zp)\mathrm{PFOVcost}(z, zp)(.5)\mathrm{crf}(z, zp)}{(1+\mathrm{disc})^{ty-1}}$$

Note that since new capacity added in the {“z,zp”} direction also expands capacity in the {“zp,z”} direction, the capital costs are split in half - hence the (.5) in the expression. Note also no expansion step is needed, since transmission expansion is always continuous.

The parameters for these equations - “Oexpcost(z,i)”, “HOVcost(z,ih)”, and “PFOVcost(z,zp)” - the three expansion costs per MW of capacity added, as well as “crfi(z,i)”, “crfih(z,ih)” and “crf(z,zp)” - the capital recovery factors for each type of equipment - are tabled in the appendix to this section.

The equations, in GAMS format, for old sites/lines are as follows, as equations "CONCOST1", (Main.gms file, section 17); "CapcostHO", (Main.gms file, section 10); and "CapcostPFO"; (Main.gms file, section 12)

```
*      thermo constructin costs:
equation CONCOST1;      {expansion costs of old thermo plants}
CONCOST1(ty) ..  PGOcapcost(ty) =E=
sum((tyb,z,i)$(ord(tyb) LE ord(ty)),
          PGOexp(tyb,z,i)*PGOexpstep(z,i)*Oexpcost(z,i)*crfi(z,i) )
/(1+disc)**(HA(ty)-1);

*+++ Old Hydros +++++++++++++++++++++++++++++++++++++++++++++++
Equation CapcostHO; {Old hydros Capital Cost}
CapcostHO(ty) ..
HOcapcost(ty) =E=
sum((tye,z,ih)$(ord(tye) LE ord(ty)),
          HOVcost(z,ih)*HOVexp(tye,z,ih)*HOexpstep(z,ih)*crfih(z,ih) )
/(1+disc)**(HA(ty)-1);

*+++ Old transmission lines capacity expansion ++++++++++++++++++++
Equation CapcostPFO; {Old Lines PW Capital cost}
CapcostPFO(ty) ..
PFOcapcost(ty) =E=
sum((tye,z,zp)$(ord(tye) LE ord(ty)),
               PFOVcost(z,zp)*PFOVexp(tye,z,zp)*0.5*crf(z,zp) )
/(1+disc)**(HA(ty)-1);
```

B) <u>New Sites/Lines</u>

The difference between existing and new site development is that initial construction site preparation and initial capacity installation must be completed before any site expansion takes place.

The generic equation for the present value at "t"=0 of capital expenses in year "ty" for a given technology at site "ni" in country "z" is;

PGNcapcost(ty) =

$$\left[\sum_{tya=1}^{ty} \frac{\left[(\mathrm{NFcost}(z,ni)\mathrm{Y}(tya,z,ni) + \mathrm{PGN}\exp(tya,z,ni)\mathrm{Nexpstep}(z,ni)\mathrm{Nexpcost}(z,ni)\right](\mathrm{crfn}(z,ni))}{(1+\mathrm{disc})^{ty-1}}\right]$$

"NFcost(z,ni)" is a parameter, in the appendix for each technology, giving the fixed cost of the initial plant at site "ni", "Y(tya,z,ni)" is the binary decision variable which is 1 if a new plant is built at site "ni" in "tya", 0 otherwise. "PGNexp(tya,z,ni)" is a continuous or integer decision variable which gives the amount of site expansion which takes place in year "tya"; "Nexpstep(z,ni)" is a fixed MW value. "Nexpcost(z,ni)" (tabled in the appendix), a parameter, gives the expansion cost/unit for each technology where expansion is allowed; "crfn(z,ni)" a parameter giving the capital recovery factor appropriate for the location of the site and the type of equipment, and "disc", the discount rate used in the objective function.

To understand the logic of the equation, the capital cost term in year "ty" should include the annualized capital expense charges for all projects initiated up to and including year "ty". Hence, the cost in "ty" is the sum of the annualized cost of projects initiated in year 1, year 2, and so forth up to and including year "ty". The annualized cost of projects started in year 1 is [FGN(z,ni)Y(1,z,ni)+PGNexp(1,z,ni)PGNexpstep(z,ni)Nexpcost(z,ni)][crfn(z,ni)], in year 2 [FGN(z,ni)Y(2,z,ni)...], etc. Using "tya" as the alias for year "ty", the total annualized costs in year "ty" can be written;

$$\sum_{tya=1}^{ty}\left[\mathrm{FGN}(z,ni)\,Y(tya,z,ni)+\mathrm{PGN}\exp(tya,z,ni)\,\mathrm{PGNexpstep}(z,ni)(\mathrm{Nexpcost}(z,ni))\right]\left[\mathrm{crfn}(z,ni)\right]$$

and the present value at "t"=0 of these charges is the above expression times $\dfrac{1}{(1+\mathrm{disc})^{ty-1}}$.

C) <u>New Thermal Sites</u>

These equations for the four new thermal options - the two which allow expansion - combined cycle ("CC") and large coal ("LC"), and the two which only allow initial construction - small coal ("SC") and combustion turbine ("T") - are given below in GAMS format.

The GAMS equation first lists the expansion costs of "NT", "SC", "CC" and "LC", and then the initial construction costs for "CC" and "LC".

The parameters for the initial fixed costs of "CC" and "LC" - Tables "FGCC(z,ni)" and "FGLC(z,ni)" - "NT", "SC", "CC", and "LC" plants - Tables "NTexpstep(z,ni)", "NSCexpstep(z,ni)", "NCCexpstep(z,ni)", and "NLCexpstep(z,ni)" - and the expansion step costs for "NT", "SC", "CC" and "LC" - Tables "NTexpcost(z,ni)", "NSCexpcost(z,ni)", "NCCexpcost(z,ni)", "NLCexpcost(z,ni)" and the captial recovery factors "crfnh" - are given in the appendix to the chapter.

D) <u>New Hydro Sites</u>

The present value at "t"=0 of the capital costs in year "ty" for new hydro plants installed up to and including year "ty" are given below in GAMS format.

The parameters for the new hydro sites - the initial fixed costs - "HNFcost(z,nh)", the expansion costs per MW - "HNVcost(z,nh)", the expansion step size - "HNVexpstep(z,nh)" and the capital recovery factors "crfnh(z,in)" - are given in the appendix. Recall that the initial fixed costs include the site preparation, dam construction, and installation of the initial generating capacity; expansion costs are for adding generating units to the existing dam, not for expansion of the dam's capacity.

E) <u>New Transmission Lines</u>

Finally, the capital costs charged in year "ty" for transmission construction projects completed up to and including year "ty" is:

Again, the parameters "PFNFcost(z,zp)" and "PFNVcost(z,zp)" and "crf(z,zp)" for new transmission lines are given in the appendix. (No "expstep" is needed for transmission, since it is always continuous.)

Since all the present values of the capital charges are for a given year "ty", they need to be weighted by the number of years each represents - Table "Mperiod(ty)" in the appendix - and summed, e.g;

$$\text{Present Value of all Captial Costs} = \sum_{ty=1}^{Y} \text{Mperiod}(ty)\left[\text{PGOcapcost}(ty) + \ldots + \text{PFOcapcost}(ty)\right]$$

The capital costs for new construction in GAMS format are, in equations "CONCOST2", (Main.gms file, section 17); "CapcostH", (Main.gms file, section 9); and "CapcostPF"; (Main.gms file, section 11)

```
equation CONCOST2;{construction & expansion costs of new thermo plants}
CONCOST2(ty) ..      PGNcapcost(ty) =E=
(  sum((tyb,z,ni)$(ord(tyb) LE ord(ty)),
             (  PGNTexp(tyb,z,ni)*NTexpstep(z,ni)*NTexpcost(z,ni)
          + PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)*NCCexpcost(z,ni)
          + PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)*NSCexpcost(z,ni)
               + PGNLCexp(tyb,z,ni)*NLCexpstep(z,ni)*NLCexpcost(z,ni) )*crfni(z,ni) )
 + sum((tya,z,ni)$(ord(tya) LE ord(ty)),
             (  FGCC(z,ni)*YCC(tya,z,ni) + FGLC(z,ni)*YLC(tya,z,ni) )*crfni(z,ni) )
)/(1+disc)**(HA(ty)-1);
```

```
*+++ New Hydros ++++++++++++++++++++++++++++++++++++++++++++++++++
                    Equation CapcostH; {New Hydros CapitaL cost}
                    CapcostH(ty) ..
                    HNcapcost(ty) =E=
                    sum((z,nh,tye)$(ord(tye) LE ord(ty)),
                               (HNFcost(z,nh)*Yh(tye,z,nh)
                         + HNVcost(z,nh)*HNVexp(tye,z,nh) *HNexpstep(z,nh)
                               )*crfnh(z,nh)
                      )
                    /(1+disc)**(HA(ty)-1);

*+++ New Transmission Interconnectors ++++++++++++++++++++++++++++++
                    Equation CapcostPF; {New Tie lines Capital cost (PW)}
                    CapcostPF(ty) ..
                    PFNcapcost(ty) =E=
                    sum((z,zp,tye)$(ord(tye) LE ord(ty)),
                        (PFNFcost(z,zp)*Ypf(tye,z,zp)+PFNVcost(z,zp)*PFNVexp(ty,z,zp)
                        )*0.5*crf(z,zp)
                      )
                    /(1+disc)**(HA(ty)-1);
```

F) <u>Old Pump Storage</u>

Letting “PSOexpcost(i)” and “crfpso(i)” be the expansion cost/MW and the capital recovery factor for pumped storage, the SAPP wide present value of the capital cost of existing pumped storage capacity expansion in year “ty”, “PSOcapcost(ty)” is;

$$\text{PSOcapcost(ty)} = \sum_{z} \sum_{\tau=1}^{ty} \frac{\text{PSOexp}(\tau, z)\text{PSOexpstep(z)PSOexpcost(z)crfpso(z)}}{(1+\text{disc})^{ty-1}}$$

The current model does not allow expantion, hence “PSOcapcost(ty)” = 0.

G) <u>New Pumped Storage</u>

In the same manner, letting “Yph(ty,z,phn)” be a binary variable indicating initial construction at site “phn” in “z”, “PHNFcost(z,phn)” the fixed cost of such development, “PSNexpcost(z,phn)” the cost/MW of capacity expansion after initial development at site “phn” and “crfpso(·)” the capital recovery factor for new pumped storage, we have; the present value at “t”=0 of the capital charges associated with construction of new pumped storage in year “ty”, “PSNcapcost(ty)” is;

$$\sum_{phn}\sum_{z}\sum_{\tau=1}^{ty}\frac{[PHNFcost(z,phn)Yph(\tau,z,phn)+PSNexp(\tau,z,phn)PSNexpstep(z,phn)PSNexpcost(z,phn)][crfpsn(z)]}{(1+disc)^{ty-1}}$$

The current model does not allow expansion at new sites; hence, only the first term in the bracket is non-zero. In GAMS format; (Main.gms file, section 25 & 26)

```
Table PHNFcost(z,phn) Pumped Hydro Fixed Capital Cost (US$)
            phn1    phn2    phn3    phn4
     SSA    373e6   377e6   377e6   237e6 {BHB/JLP Oct 13 1998}

Equation CapcostPH; {New Pumped Hydros Capital cost}
CapcostPH(ty) ..
PHNcapcost(ty) =E=
sum((z ,phn,tye)$(ord(tye) LE ord(ty)),
       (PHNFcost(z,phn)*Yph(tye,z,phn)
       )*crfphn(z,phn) ) /(1+disc)**(HA(ty)-1);
```

4.4.4 Final Expression of the Objective Function

The complete statement of the objective function in GAMS format, is in equation “objf”; (Main.gms file, section 27)

```
*** objective function *******************************************
          EQUATIONS objf;
          objf ..  sappcst =E=

           SUM((ty,ts,td,th,z), Mperiod(ty)*Mseason(ts)*Mday(td)*Mtod(th)*
            {fuel costs}  (  sum(i,  PG(ty,ts,td,th,z,i)*(HRO(z,i)*fpO(z,i)
                                  *power(fpescO(z,i),(HA(ty)-1)) + OMO(z,i)) )
                 +sum(ni, PGNT(ty,ts,td,th,z,ni)*(HRNT(z,ni)*fpNT(z,ni)
                                  *power(fpescNT(z),(HA(ty)-1)) + OMT(z,ni)) )
                        +sum(ni, PGNCC(ty,ts,td,th,z,ni)*(HRNCC(z,ni)*fpNCC(z,ni)
                                  *power(fpescNCC(z),(HA(ty)-1)) + OMCC(z,ni)) )
                        +sum(ni, PGNSC(ty,ts,td,th,z,ni)*(HRNSC(z,ni)*fpNSC(z,ni)
                                  *power(fpescNSC(z),(HA(ty)-1)) + OMSC(z,ni)) )
                        +sum(ni, PGNLC(ty,ts,td,th,z,ni)*(HRNLC(z,ni)*fpNLC(z,ni)
                                  *power(fpescNLC(z),(HA(ty)-1)) + OMLC(z,ni)) )
            {Cost of water} +sum(ih, wcost*H(ty,ts,td,th,z,ih)      )
                        +sum(nh, wcost*Hnew(ty,ts,td,th,z,nh)   )
            {UE costs}     +UEcost*UE(ty,ts,td,th,z)
                        )/(1+disc)**(HA(ty)-1)
            )

           {Capital Cost}
          + sum(ty, Mperiod(ty)*(   PGOcapcost(ty) + PGNcapcost(ty)
                                  + HOcapcost(ty)  + HNcapcost(ty)
                                  + PFOcapcost(ty) + PFNcapcost(ty)
                                      + PHNcapcost(ty)

                              )
            );
```

4.4.5 The Budget Constraint

While SAPP access to the capital markets is substantial, it is not unlimited. It is more likely that SAPP would have access to a fixed amount of funds per year from the various lending agencies with an interest in the region. Since the exact amount per year that would be available from lending agencies is not known, the model sets upper and lower limits on the amount available to finance new construction.

The constraints are of the form

$$\left.\begin{array}{l}\sum_{i} \mathrm{PGOexp(ty)PGOexpstep}(\cdot)\mathrm{Oexpcost}(\cdot) \\ + \\ \sum_{ih} \mathrm{HOVexp(ty)HOVexpstep}(\cdot)\mathrm{HOVcost}(\cdot) \\ + \\ \sum_{z,zp} \mathrm{PFOVexp(ty)PFOVc}(\cdot)\end{array}\right\}\text{old expansion}$$

$$\left.+\sum_{ni,nh,z,zp} \mathrm{FGN}(z,ni)\mathrm{Y(ty)} + \mathrm{PGNexp(ty)Nexpstep}(\cdot)\mathrm{Nexpcost}(\cdot)\right\}\text{new construction expansion}$$

$$\geq \min(\mathrm{ty}) \leq \max(\mathrm{ty}) \text{ for all ty}$$

The constraints in GAMS format are as follows, in equations “Budgetmin” and “Budgetmax”; (Main.gms file, sections 28)

```
equation BUDGETmin;
BUDGETmin(ty)$(ord(ty) GE 2) ..
   sum((tyb,z,i)$(ord(tyb) EQ ord(tyb)),
            PGOexp(tyb,z,i)*PGOexpstep(z,i)*Oexpcost(z,i))
 + sum((tyb,z,ni)$(ord(tyb) EQ ord(ty)),
                 PGNTexp(tyb,z,ni)*NTexpstep(z,ni)*NTexpcost(z,ni)
               + PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)*NCCexpcost(z,ni)
               + PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)*NSCexpcost(z,ni)
               + PGNLCexp(tyb,z,ni)*NLCexpstep(z,ni)*NLCexpcost(z,ni) )
 + sum((tya,z,ni)$(ord(tya) EQ ord(ty)),
                 FGCC(z,ni)*YCC(tya,z,ni) + FGLC(z,ni)*YLC(tya,z,ni) )
 + sum((z,nh,tye)$(ord(tye) EQ ord(ty)),
                 HNFcost(z,nh)*Yh(tye,z,nh) + HNVcost(z,nh)*HNVexp(tye,z,nh) )
 + sum((z,phn,tye)$(ord(tye) EQ ord(ty)),
                 PHNFcost(z,phn)*Yph(tye,z,phn) )
 + sum((tye,z,ih)$(ord(tye) EQ ord(ty)), HOVcost(z,ih)*HOVexp(ty,z,ih) )
 + sum((z,zp,tye)$(ord(tye) EQ ord(ty)),
            PFNFcost(z,zp)*Ypf(tye,z,zp)+PFNVcost(z,zp)*PFNVexp(ty,z,zp) )
 + sum((tye,z,zp)$(ord(tye) LE ord(ty)),
```

```
                  PFOVcost(z,zp)*PFOVexp(ty,z,zp)*0.5 )
=G= n * 0.1e9;
equation BUDGETmax;
BUDGETmax(ty)$(ord(ty) GE 2) ..
   sum((tyb,z,i)$(ord(tyb) EQ ord(tyb)),
             PGOexp(tyb,z,i)*PGOexpstep(z,i)*Oexpcost(z,i))
 + sum((tyb,z,ni)$(ord(tyb) EQ ord(ty)),
      PGNTexp(tyb,z,ni)*NTexpstep(z,ni)*NTexpcost(z,ni)
                 + PGNCCexp(tyb,z,ni)*NCCexpstep(z,ni)*NCCexpcost(z,ni)
                 + PGNSCexp(tyb,z,ni)*NSCexpstep(z,ni)*NSCexpcost(z,ni)
                 + PGNLCexp(tyb,z,ni)*NLCexpstep(z,ni)*NLCexpcost(z,ni) )
 + sum((tya,z,ni)$(ord(tya) EQ ord(ty)),
                  FGCC(z,ni)*YCC(tya,z,ni) + FGLC(z,ni)*YLC(tya,z,ni) )
 + sum((z,nh,tye)$(ord(tye) EQ ord(ty)),
                  HNFcost(z,nh)*Yh(tye,z,nh) + HNVcost(z,nh)*HNVexp(tye,z,nh) )
 + sum((z,phn,tye)$(ord(tye) EQ ord(ty)),
                  PHNFcost(z,phn)*Yph(tye,z,phn) )
 + sum((tye,z,ih)$(ord(tye) EQ ord(ty)), HOVcost(z,ih)*HOVexp(ty,z,ih) )
 + sum((z,zp,tye)$(ord(tye) EQ ord(ty)),
             PFNFcost(z,zp)*Ypf(tye,z,zp)+PFNVcost(z,zp)*PFNVexp(ty,z,zp) )
 + sum((tye,z,zp)$(ord(tye) LE ord(ty)),
                  PFOVcost(z,zp)*PFOVexp(ty,z,zp)*0.5 )
=L= n * 5e9;
```

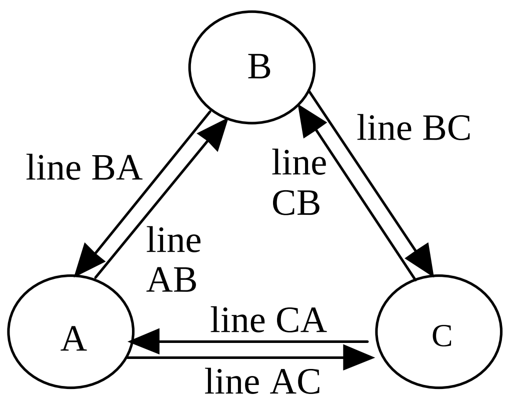
Appendix 1 to Chapter Two

Here, a simplified 3-country version of the model in Chapter Two is presented along with the GAMS input and output files.

Figure 2.3 shows a simplified network connecting 3 countries, each with a single generating station. Current capacities, costs, and line losses are given in the tables below. (Data assumes country A is South Africa, country C is the sum of MOZ, DRC, ZAM, and ZIM, country B is ANG, BOT, LES, MWI, NAM, SWZ, TAZ). The units in A and B are assumed to be fossil fueled, while C is assumed to be hydro.

Figure names correspond to the table, scalar, and parameter titles in the GAMS input files in the full version of the model described later in the text. As before, “z” is the country index, (z = A, B, C in the example) and “i” the plant index (i = 1 in the example).

FIGURE 2.3: 3 Country Model



I. *The Demand Module*

In this example, the model is driven by one representative day’s demand in each of three years, each year representing growing demand 5, 10, and 15 years from the present. (The full model allows the user to specify other time dimensions of the problem.)

Each representative day contains six representative hours; one off peak hour (hour 9 of 24) three possible peak hours (hours 19, 20, 21) and two average hours (one day, one night) each weighted so that total demand for the six hours equals demand for the 24 hour period. As the table below shows, hour 19 is the peak hour in the data; all other hours - 9, 20, 21, avnt, and avday - are considered off peak. (Again the full model allows demands of up to 24 hours per day to be specified for each country.)

These demands, along with the growth rates assumed for each country, are given in the tables below. Growth percentages are for 5-year intervals based on yearly growth for A, B, and C being 1.036, 1.07, and 1.06, respectively. Domestic loss coefficients are given in Table "DLC(z)". No DSM is assumed in the example.

Table: July 24 97 (th,z)

(hourly demand in MW)

		Country "z"		
weight	hour "th"	A	B	C
1	hour 9	26,400	1300	3600
8	avnt	20,600	1000	2700
1	hour 19	27,600	1300	3600
1	hour 20	26,800	1300	3600
1	hour 21	25,800	1300	3500
12	avdy	23,300	1200	3400

Parameter dgrowth(z)

(5 year percentage growth in demand)

A	1.20
B	1.40
C	1.34

Table DLC(z)

(domestic distribution loss)

A	1.10
B	1.05
C	1.08

Transmission line loss for the lines connecting A, B, and C are given in Table "PFloss (z,zp)".

from country "z"	to country "zp"		
	A	B	C
A	0	0.11	0.15
B	0.11	0	0.08
C	0.15	0.08	0

The demand/supply equations for each of the three countries can now be specified for each of the six hours in each of the three years.

Country A, hour 9, year 1

$$PG(9,1,A,1) + PF(9,1,B,A)(1-0.11) + PF(9,1,C,A)(1-0.15) - PF(9,1,A,B)$$

$$-PF(9,1,A,C) = (26,400)(1.1)(1.2)$$

$$\vdots$$

Country C, hour avdy, year 3

$$PG(avdy,3,C,1) + PF(avdy,3,A,C)(1-0.15) + PF(avdy,3,B,C)(1-0.08)$$

$$-PF(avdy,3,C,A) - PF(avdy,3,C,B) = (3400)(1.08)(1.34)^{3}$$

II. The Capacity Constraint Module

1. Generation

Supply in each country comes initially from a single plant, whose current capacity is given in Table "PGinit". Forced and unforced outage rates for the plants per year are given in Tables "FORPG" and "UFORP". For simplicity, no decay is assumed to take place.

Table FORPG(z,i)

Country "z"	Plant "i"
A	0.04
B	0.04
C	0.04

Table PG init(z,i) (MW)

Country "z"	Plant "i"
A	30,000
B	1800
C	9800

Table UFORP(z,i)

Country "z"	Plant "i"
A	0.10
B	0.10
C	0.10

Table “expstep(z,i)” gives the MW capacity of each unit added to existing capacity at each site “i”.

Table expstep(z,i) (MW)

Country “z”	Plant “i”
A	500
B	300
C	170

Defining “Y(y,z,i)” to be the integer varialbe = 0,1,2,3,etc., indicating how many units are installed in year “y” in country “z”, we have the following definitions:

PGexp(y,A,1) = 500Y(y,A,1) y = 1,2,3,etc.

PGexp(y,B,1) = 300Y(y.B,1) y = 1,2,3,etc.

PGexp(y,C,1) = 170Y(y,C,1) y = 1,2,3,etc.

Assuming the forced and unforced outage rates apply to old and new units alike at each plant site, the capacity constraints for peak and off-peak periods can now be constructed:

(2a) $$\mathrm{PG}(\mathrm{hr19}, 1, \mathrm{A}, 1) \leq (30{,}000 + 500\mathrm{Y}(1, \mathrm{A}, 1))(1 - 0.04)$$

$$\vdots$$

$$\mathrm{PG}(\mathrm{hr19}, 3, \mathrm{C}, 1) \leq [9{,}800 + 170\mathrm{Y}(1, \mathrm{C}, 1) + 170\mathrm{Y}(2, \mathrm{C}, 1)$$

$$+170\mathrm{Y}(3, \mathrm{C}, 1)] * (1 - 0.04),$$

(2b) $$\mathrm{PG}(\mathrm{offpeak}, 1, \mathrm{A}, 1) \leq (30{,}000 + 500\mathrm{Y}(1, \mathrm{A}, 1))(1 - 0.04)(1 - 0.10)$$

$$\vdots$$

$$\mathrm{PG}(\mathrm{offpeak}, 3, \mathrm{C}, 1) \leq [9{,}800 + 170\mathrm{Y}(1, \mathrm{C}, 1) + 170\mathrm{Y}(2, \mathrm{C}, 1)$$

$$+170\mathrm{Y}(3, \mathrm{C}, 1)] * (1 - 0.04)(1 - 0.10), \ \mathrm{offpeak} = \mathrm{hr9}, 20, 21, \mathrm{avnt}, \mathrm{avdy}$$

(In the full model, the distinction is made between peak and off-peak days, not hours within the day, as is done here to minimize time complexity.)

The hydro plant in country C has one additional capacity constraint, if it is assumed to be a reservoir facility, rather than "run of the river" – that the reservoir cannot be drained. While the full model has such a constraint in it for each reservoir – that initial volume minus total daily outflows plus daily inflows must be non-negative-here, we simply assume that the power generated over the 24 hours in the representative day cannot exceed 24 times the MW capacity during the year – e.g.,

$$
\begin{aligned}
&\mathrm{PG}(\mathrm{hr9},\mathrm{y},\mathrm{C},1) + 8\mathrm{PG}(\mathrm{avnt},\mathrm{y},\mathrm{C},1) + \mathrm{PG}(\mathrm{hr19},\mathrm{y},\mathrm{C},1) \\
&+\mathrm{PG}(\mathrm{hr20},\mathrm{y},\mathrm{C},1) + \mathrm{PG}(\mathrm{hr21},\mathrm{y},\mathrm{C},1) + 12\mathrm{PG}(\mathrm{avdy},\mathrm{y},\mathrm{C},1) \\
&\qquad \le 24\left[9800 + \sum_{\tau=1}^{y} 170\,\mathrm{Y}(\tau,\mathrm{C},1)\right] \text{ for all y}
\end{aligned}
$$

In the full model, the scalar "24" is replaced by a factor which varies, depending on the season - wet or dry.

2. *Transmission*

The current capacities of the transmission system in MW are given in the following table.

Table PFinit(z,zp) (MW)

	A	B	C
A (S.A.)	0	575	2150
B (other)	575	0	350
C (MOZ, ZAM, ZIM, DRC)	2150	350	0

It will be assumed that transmission capacity can be added in 200 MW increments. Letting "Y(y,z,zp)" be the integer variable giving the number of increments to line capacity added to line "z,zp" (and "zp,z") in year "y" we have

PFexp(y,z,zp) = 200Y(y,z,zp)

The forced outage fate for all lines “FOR(z,zp)” is assumed to be the same 0.10 figure. This data can be used to construct the capacity constraints for the transmission lines connecting A, B, and C.

Lines {AB,BA}

$$PF(t,1,A,B) \leq (575 + 200\,Y(1,A,B)(1 - 0.10)$$

$$PF(t,1,B,A) \leq (575 + 200\,Y(1,B,A)(1 - 0.10)$$

$$Y(1,A,B) = Y(1,B,A)$$

$$\vdots$$

$$PF(t,3,B,C) \leq [350 + 200\,Y(1,B,C) + 200\,Y(2,B,C)$$

$$+300Y(3,B,C)](1 - 0.10)$$

$$PF(t,3,C,B) \leq [350 + 200\,Y(1,C,B) + 200\,Y(2,C,B)$$

$$+200Y(3,C,B)](1 - 0.10)$$

$$Y(3,B,C) = Y(3,C,B)$$

III. The Reliability Module

The reliability constraints can be written with the assumption that "RES(i)" = 0.19 for thermal units, 0.10 for the hydro unit, and 0.25 for net imports:

(4a) Country A:

$$\frac{30,000 + PG\exp(1,A,1)}{1 + 0.19}$$

$$+ \frac{PF(19,1,B,A)(1 - .11) + PF(19,1,C,A)(1 - .15) - PF(19,1,A,B) - PF(19,1,A,C)}{1 + 0.25}$$

$$\geq (27,600)(1.1)(1.2)$$

$$\vdots$$

Country C:

$$\frac{2{,}800 + PG\exp(1,C,1) + PG\exp(2,C,1) + PG\exp(3,C,1)}{1+0.10}$$

$$+\ \frac{PF(20,3,B,C)(1-.08) + PF(20,3,A,C)(1-.15) - PF(20,3,C,A) - PF(20,3,C,B)}{1+0.25}$$

$$\geq (3{,}600)(1.08)(1.34)^3$$

"MaxPG(z)" will be assumed to be 10% of the total capacity for each country: hence in each:

(4b) Country A:

$$30{,}000 + PG\exp(1,A,1) + PF(19,1,B,A) + PF(19,1,C,A)$$

$$-PF(19,1,A,B) - PF(19,1,A,C) \geq (27{,}600)(1.1) + (27{,}600)(0.1)$$

$$\vdots$$

Country C: ...

IV. <u>The Country Autonomy Module</u>

Table "AF(z,y)" gives the autonomy factors assumed for each of the countries, to hold over all hours.

Table AF(z,y)

(autonomy factor)

Country "z"	Year "y"		
	1	2	3
A	0.95	0.9	0.8
B	0.45	0.35	0.3
C	1	1	1

(Since country C will export, "AF(z,y)" is assumed 1.)

Hence the equations are:

<u>Country A</u>

$$30,000 + PG\exp(1, A, 1) \geq (.95)(26,400)(1.1)(1.2)$$

$$\vdots$$

<u>Country C</u>

$$9,800 + PG\exp(1, C, 1) + PG\exp(2, C, 1) + PG\exp(3, C, 1)$$

$$\geq (1)(3,400)(1.08)(1.34)^3$$

V. The Objective Function Module

1. Operating Costs

Tables "HR(z,i)", "fp(z,i)" and "fpesc(z,i)" give the heat rates, fuel costs, and fuel escalation price rates, assumed for old and new plants in countries A, B, and C. (The heat rate for hydro is scaled to 1 to allow the water charge to be .15/MWh for the hydro facilities in country C.

Table HR (z,i)
(BTU/KWh) x 10^3

Country "z"	Plant "i"
A	9.8
B	7.5
C	1

Table fp(z,i)
($/$10^6$ BTU)

Country "z"	Plant "i"
A	0.40
B	1.00
C	0.15

Table fpesc(z,i)

Country "z"	Plant "i"
A	1.01
B	1.02
C	1.00

When the heat rates, in BTU/MWh are multiplied by the fuel costs, in $/$10^6$ BTU, the resultant charge is in $/MWh.

Since, in this example, the operating characteristics of new and old plants are assumed identical, there is no need to distinguish between the operating costs of old and new plants.

In constructing the operating cost term in the objective function, it is important to properly weight the hours of operation to insure the six representative hours add up to 24 hours of use. Parameter "Mtod(th)" gives these weights. Since one day is chosen to represent the whole year, the resultant 24 hour daily costs need to be multiplied by 365:

Parameter Mtod(th)

hr 9	1
avnt	8
hr 19	1
hr 20	1
hr 21	1
avdy	12

The yearly generation cost for year one in country A is yearly generation times year one cost/MWh, the product of the heat rate times the cost/10^6 BTU, or (9.8)(0.4) = \$3.92/MWh times the yearly generation.

Thus, yearly generation cost for the plant in country A in year "0" is:

$$
\begin{aligned}
&\left[PG(hr9,1,A,1) + 8PG(avnt,1,A,1) + PG(hr19,1,A,1) + PG(hr20,1,A,1)\right. \\
&\left.+PG(hr21,1,A,1) + 12PG(avdy,1,A,1)\right][365][3.92]
\end{aligned}
$$

and the present value at time "0" over the 15-year horizon for each of the three representative years, each representing a 5-year interval, is:

$$
\sum_{ty=1}^{3} \left[\frac{\begin{array}{l}\left[PG(hr9,ty,A,1) + 8PG(avnt,ty,A,1) + PG(hr19,ty,A,1)\right. \\ \left.+PG(hr20,ty,A,1) + PG(hr21,ty,A,1) + 12PG(avdy,ty,A,1)\right] \\ \quad (3.92)365[1.01]^{5ty}\end{array}}{(1+disc)^{5ty}} \right]
$$

The discount rate is given in the Table "scalar int"; the normal value is 10%; users can specify other values.

Similar present value terms for fuel costs can be constructed for countries B and C.

2. New Equipment Costs

Each country's plant can be expanded in fixed increments during each time period. "PGexp(y,z,i)" is the amount added to country "z's" capacity in period "y". Characteristics of the plant expansion for each country are given below.

Characteristic	Country		
	A	B	C
Fixed cost (\$ x 10^6)	580	430	125
Fixed capacity (MW)	500	300	170

(Country A's plant is a large coal facility, country B a smaller coal plant, and country C added hydro capacity for the example.) Recalling that "Y(y,z,i)" indicates the number of units added in year "y", total investment in year "y" in each country is then (580)Y(y,A,1) for A, (430)Y(y,B,1) for B, and 125Y(y,C,1) for C.

The capital recovery factors for plants in A and B are assumed to be 0.16 while C, the hydro facility, having a longer life, is 0.12. The per period charges for new capacity in each country is then (0.16)(580)Y(y,A,1) for A, (0.16)(430)Y(y,B,1) for B, and (0.12)(125)Y(y,c,1) for C.

The present value at time "0" of these to the end of the planning horizon, using the general expression

$$\sum_{y=1}^{Y} \sum_{\tau=1}^{y} \frac{\mathrm{CRF}(r,n)\mathrm{expcost}(z,i)Y(\tau,z,i)}{(1+\mathrm{disc})^{y}}$$

is then:

Present Value of;

Country	Charges in the first period	Charges in the second period	Charges in the third period
A	$\frac{(.16)(580)Y(1,A,1)}{(1.1)^5}$	$\sum_{\tau=1}^{2}\frac{(.16)(580)Y(\tau,A,1)}{(1.1)^{10}}$	$\sum_{\tau=1}^{3}\frac{(.16)(580)Y(\tau,A,1)}{(1.1)^{15}}$
B	$\frac{(.16)(430)Y(1,B,1)}{(1.1)^5}$	$\sum_{\tau=1}^{2}\frac{(.16)(430)Y(\tau,B,1)}{(1.1)^{10}}$	$\sum_{\tau=1}^{3}\frac{(.16)(430)Y(\tau,B,1)}{(1.1)^{15}}$
C	$\frac{(.12)(125)Y(1,C,1)}{(1.1)^5}$	$\sum_{\tau=1}^{2}\frac{(.12)(125)Y(\tau,C,1)}{(1.1)^{10}}$	$\sum_{\tau=1}^{3}\frac{(.12)(125)Y(\tau,C,1)}{(1.1)^{15}}$

All that remains is to enter the transmission capacity equation costs into the objective function. It will be assumed that capacity can be added in 200 MW increments with the cost per increment according to the following table;:

Table PFOVC (z,zp) ($ x $10^{6)}$

	To		
From	A	B	C
A	0	30	300
B	30	0	30
C	300	30	0

In a manner analogous to generation capacity expansion, we have:

PFexp(y,z,zp) = 200Y(y,z,zp) for all y, z, and zp

where Y(y,z,zp) = 0, 1, 2, 3...., and each expansion adds 200 MW to capacity.

Costs of transmission capacity expansion differ depending on the arc -- e.g., the cost per 200 MW expansion for each arc is:

arc AB $= \dfrac{30Y(y, A, B)}{2}$

arc BA $= \dfrac{30Y(y, B, A)}{2}$

arc AC $= \dfrac{300Y(y, A, C)}{2}$

arc CA $= \dfrac{300Y(y, C, A)}{2}$

arc CB $= \dfrac{30Y(y, C, B)}{2}$

arc BC $= \dfrac{30Y(y, B, C)}{2}$

and Y(y,z,zp) = Y(y,zp,z) for all pairs.

The present value of the annual charges from time of installation to the end of the planning horizon, as in the case of generation expansion, is given in the following table, assuming a CRF of 12% for all lines:

Present value of;

Arc	Charges in first period	Charges in second period	Charges in third period
A,B	$\dfrac{(.12)(30)Y(1, A, B)}{(2)(1.1)^5}$	$\sum_{\tau=1}^{2}\dfrac{(.12)(30)Y(\tau, A, B)}{(2)(1.1)^{10}}$	$\sum_{\tau=1}^{3}\dfrac{(.12)(30)Y(\tau, A, B)}{(2)(1.1)^{15}}$
B,A	$\dfrac{(.12)(30)Y(1, B, A)}{(2)(1.1)^5}$	$\sum_{\tau=1}^{2}\dfrac{(.12)(30)Y(\tau, B, A)}{(2)(1.1)^{10}}$	$\sum_{\tau=1}^{3}\dfrac{(.12)(30)Y(\tau, B, A)}{(2)(1.1)^{15}}$
⋮			

The full model input file in GAMS format, and the results of the optimization follows.

A) Demand

The model is driven by the "typical hour/day/season/year" chronological demand approach taken by many of the latest commercial models, rather than the load duration curve methodology used in earlier approaches.

Each SAPP region enters in "Table 2000 day type td(th,z)", their 24-hour base year MW load patterns for 6 day types -- summer peak, off-peak, and average days, and winter peak, off-peak, and average day patterns. (2000 was chosen as the base to allow for known growth in demand in the early years.) Depending on the option chosen by the user, the 24-hour pattern itself, a 6-hour approximation of the 24-hour pattern (consisting of 4 peak and 2 off-peak hours) or a 1-hour option can be chosen, depending on the nature of the run, and the trade-off in the user's mind between accuracy and running time. (The 24-hour model can take several hours to run, while the 6-hour model usually takes less than 50 minutes without a large reduction in accuracy.)

Scalar multiples are applied to the representative hours ("parameter Mtod(th1)") to scale up the sample hours to represent the demand over each 24-hour period.

Scalar multiples are also applied to each of the three day types in the summer (9 months) and winter (3 months) seasons ("parameter Mday(td)") to insure each year has 365 demand days.

Seven representative years are chosen to model demand growth over the model's 20-year planning horizon. Since greater timing detail is needed in the first 10 years than the second, every other year is modeled for the first 10 years; thereafter every fifth year is represented for a total of seven years over the 20-year horizon. Yearly demand growth rates which differ by day type, by time period, and by country ("parameter dgrowth1(z,td)", to "dgrowth6(z,td)" in the model) are specified by the user. The program automatically converts the yearly growth rates into the proper growth rates for the 2- and 5-year intervals between years.

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, Mozambique, and the Democratic Republic of the Congo are represented by two demand nodes each rather than one.

Two other terms appear in the model in association with demand – the Domestic Loss Coefficient and Demand-Side Management. The domestic loss coefficient – ("parameter "DLC(z)") in the model – is applied to the demand value to allow for electricity loss within each

SAPP region. Thus, it converts demand at the customer meter into demand at the generating station.

The demand-side management (DSM) parameter – (“LM(th,z)” in the model) – allows SAPP member specified DSM options to fractionally adjust up or down the load shapes of the representative days in the model, with user-specified costs of such programs entered into the objective function. It should be emphasized that the model does not compete DSM against normal supply side options to obtain the least cost mix of DSM and capacity expansion. It simply allows various DSM options with known costs and benefits to be entered into the model to see “off-line” if they are cost effective.

The upshot of all this is the specification of the right-hand side of the load balance equation, which specifies: for each hour in each day in each season in each year, the demand at the generating station that must be met inclusive of the effect of distribution line loss and DSM programs. Letting Dyr(ty,ts,td,th,z) be the country z’s MW demand during hour “th” of day type “td” in season “ts” during year ty, we have:

$$\mathrm{Dyr(ty, ts, td, th, z) = 2000\ Day type\ "td"(th, z)\left(1 + dgrowth(td, z)\right)^{ty}}$$

and total demand in country z to be met at the generating stations in the interval {ty,ts,td,th} is then:

$$\mathrm{Dyr(ty, ts, td, th, z)(DLC(z)) - DSM(th, z)}$$

Appendix 1A to Chapter 4 Data Tables
(The Demand for Electricity)

```
(data file, section 2)
parameter dgrowth2(z)   {demand growth rate for period 2}
/Ang    1.079      This is where users enter the annual growth rates by
country.
 Bot    1.043      Default rates from Peter Robinson's projections given at
 Les    1.061     July 98 Cape Town workshop
 Mwi    1.032
 NMz    1.108
 SMz    1.109
 Nam    1.072
 NSA    1.036
 SSA    1.036
 Swz    1.034
 Taz    1.060
 DRC    1.050
 Zam    1.044
 Zim    1.041
/;

(data file, section 3)
parameter dgrowth3(z) {demand growth rate for period 3}
/Ang    1.079
 Bot    1.043
 Les    1.061
 Mwi    1.032
 NMz    1.108
 SMz    1.109
 Nam    1.072
 NSA    1.036
 SSA    1.036
 Swz    1.034
 Taz    1.060
 DRC    1.050
 Zam    1.044
 Zim    1.041
/;

(data file, section 4)
parameter dgrowth4(z) {demand growth rate for period 4}
/Ang    1.079
 Bot    1.043
 Les    1.061
 Mwi    1.032
 NMz    1.108
 SMz    1.109
 Nam    1.072
 NSA    1.036
 SSA    1.036
 Swz    1.034
 Taz    1.060
 DRC    1.050
 Zam    1.044
 Zim    1.041
/;
```

```
(data file, section 4)
parameter dgrowth5(z) {demand growth rate for period 5}
/Ang    1.079
 Bot    1.043
 Les    1.061
 Mwi    1.032
 NMz    1.108
 SMz    1.109
 Nam    1.072
 NSA    1.036
 SSA    1.036
 Swz    1.034
 Taz    1.060
 DRC    1.050
 Zam    1.044
 Zim    1.041

/;

(gms. file, section 1)
scalar  n   number of years in each time interval  / 5 /;

parameter Mperiod(ty)  multiplier of year;
Mperiod(ty) = n;

Parameter dgr(z,ty);
   dgr(z,'yr2') = power (dgrowth2(z),2*n);
   dgr(z,'yr3') = power (dgrowth2(z),2*n) * power (dgrowth3(z),n);
   dgr(z,'yr4') = power (dgrowth2(z),2*n) * power (dgrowth3(z),n) *
                  power(dgrowth4(z),n);
   dgr(z,'yr5') = power (dgrowth2(z),2*n) * power (dgrowth3(z),n) *
                  power(dgrowth4(z),n) * power (dgrowth5(z),n);

parameter HA(ty);
HA(ty) = n*(1+ord(ty));

Parameter DW;
   DW = n;

*=== sapp98model/demand.inc ====

******************************   Section  1
**********************************


* This is the demand for year 2000!

*****************************************************************
* Be sure change july2497(th,z) and PeakD(ty,z)                 *
*****************************************************************

$ontext
*-------------------- One hour demand data -----------------------
SET th      Hours index        / hr19  /;
scalar thT number of hours in a day /1/;
```

```
Table PeakD(ty,z)
     Ang Bot Les Mwi NMz SMz Nam NSA   SSA  Swz Taz DRC  Zam  Zim
yr1  215 208 66  185 53  101 271 22287 5309 118 416 618  1025 1885
;

Table   july2497(th,z) Hourly System load on July 24 1997
      Ang     Bot     Les     Mwi     NMz     SMz     Nam
hr19    215     208     66      185     53      101     271

+       NSA     SSA     Swz     Taz     DRC     Zam     Zim
hr19  22287 5309  118         416     618     1025    1885
;
$offtext

******************************   Section  2
**********************************


*--------------------- Six hour demand data ----------------------
                                    {weights}
scalar thT number of hours in a day /6/;

Parameter Mtod(th) /
hr9   1
avnt    8
hr19  1
hr20  1
hr21  1
avdy  12 / ;

Table PeakD(ty,z)       {peak demand for each region in each year}
     Ang Bot Les Mwi    NMz SMz Nam NSA   SSA  Swz Taz DRC  Zam  Zim
yr2  215 211  74 156.4  81 101 296 22287 5309 118 416 721  1062 1885
;

******************************   Section  3
**********************************


Table   july2400(ts,td,th,z) Hourly System load on July 24 1997

                  Ang   Bot   Les   Mwi   NMz   SMz   Nam
winter.peak.hr9         215   211   74    144   81    70    286
winter.peak.avnt  185   149   45    101.7 47    61    204
winter.peak.hr19  214   189   66    156.4 53    101   271
winter.peak.hr20  215   191   71    137.5 69    95    298
winter.peak.hr21  214   189   66    123.5 64    91    296
winter.peak.avdy  200   185   60    133.1 73    72    270

winter.average.   hr9   172   168.8 59.2  115.2 64.8  56    228.8
winter.average.   avnt  148   119.2 36    81.36 37.6  48.8  163.2
winter.average.   hr19  171   151.2 52.8  125.12      42.4  80.8  216.8
winter.average.   hr20  172   152.8 56.8  110   55.2  76    238.4
winter.average.   hr21  171   151.2 52.8  98.8  51.2  72.8  236.8
winter.average.   avdy  160   148   48    106.48      58.4  57.6  216
```

```
winter.offpeak.   hr9   150.5 147.7 51.8  100.8 56.7  49    200.2
winter.offpeak.   avnt  129.5 104.3 31.5  71.19 32.9  42.7  142.8
winter.offpeak.   hr19  150.5 132.3 46.2  109.48      37.1  70.7  189.7
winter.offpeak.   hr20  150.5 133.7 49.7  96.25 48.3  66.5  208.6
winter.offpeak.   hr21  150.5 132.3 46.2  86.45 44.8  63.7  207.2
winter.offpeak.   avdy  140   129.5 42    93.17 51.1  50.4  189

summer.peak.      hr9   193.5 189.9 66.6  129.6 72.9  63    257.4
summer.peak.      avnt  166.5 134.1 40.5  91.53 42.3  54.9  183.6
summer.peak.      hr19  193.5 170.1 59.4  140.76      47.7  90.9  243.9
summer.peak.      hr20  193.5 171.9 63.9  123.75      62.1  85.5  268.2
summer.peak.      hr21  193.5 170.1 59.4  111.15      57.6  81.9  266.4
summer.peak.      avdy  180   166.5 54    119.79      65.7  64.8  243

summer.average.   hr9   154.8 151.92      53.28 103.68      58.32 50.4
      205.92
summer.average.   avnt  133.2 107.28      32.4  73.224      33.84 43.92
      146.88
summer.average.   hr19  154.8 136.08      47.52 112.608     38.16 72.72
      195.12
summer.average.   hr20  154.8 137.52      51.12 99    49.68 68.4  214.56
summer.average.hr21     154.8 136.08      47.52 88.92 46.08 65.52 213.12
summer.average.avdy     144   133.2 43.2  95.832      52.56 51.84 194.4

summer.offpeak.hr9      135.45      132.93      46.62 90.72 51.03 44.1
      180.18
summer.offpeak.avnt     116.55      93.87 28.35 64.071      29.61 38.43
      128.52
summer.offpeak.hr19     135.45      119.07      41.58 98.532      33.39 63.63
      170.73
summer.offpeak.hr20     135.45      120.33      44.73 86.625      43.47 59.85
      187.74
summer.offpeak.hr21     135.45      119.07      41.58 77.805      40.32 57.33
      186.48
summer.offpeak.avdy     126   116.55      37.8  83.853      45.99 45.36 170.1

*******************************   Section  4
***********************************


+                 NSA   SSA   Swz   Taz   DRC   Zam   Zim
winter.peak.hr9         21269 5142  112   416   670   1025  1829
winter.peak.avnt  16529 3713  77    378   457   866   1214
winter.peak.hr19  22287 5309  118   416   618   1025  1885
winter.peak.hr20  21648 5167  114   416   670   1068  1762
winter.peak.hr21  20814 4976  103   416   721   1047  1679
winter.peak.avdy  19803 4754  99    397   630   968   1753

winter.average.hr9      17015.2     4113.6      89.6  332.8 536   820
      1463.2
winter.average.avnt     13223.2     2970.4      61.6  302.4 365.6 692.8 971.2
winter.average.hr19     17829.6     4247.2      94.4  332.8 494.4 820   1508
winter.average.hr20     17318.4     4133.6      91.2  332.8 536   854.4
      1409.6
winter.average.hr21     16651.2     3980.8      82.4  332.8 576.8 837.6
      1343.2
```

```
winter.average.avdy     15842.4     3803.2      79.2  317.6 504   774.4
      1402.4

winter.offpeak.hr9      14888.3     3599.4      78.4  291.2 469   717.5
      1280.3
winter.offpeak.avnt     11570.3     2599.1      53.9  264.6 319.9 606.2 849.8
winter.offpeak.hr19     15600.9     3716.3      82.6  291.2 432.6 717.5
      1319.5
winter.offpeak.hr20     15153.6     3616.9      79.8  291.2 469   747.6
      1233.4
winter.offpeak.hr21     14569.8     3483.2      72.1  291.2 504.7 732.9
      1175.3
winter.offpeak.avdy     13862.1     3327.8      69.3  277.9 441   677.6
      1227.1

summer.peak.hr9         19142.1     4627.8      100.8 374.4 603   922.5
      1646.1
summer.peak.avnt  14876.1     3341.7      69.3  340.2 411.3 779.4 1092.6
summer.peak.hr19  20058.3     4778.1      106.2 374.4 556.2 922.5 1696.5
summer.peak.hr20  19483.2     4650.3      102.6 374.4 603   961.2 1585.8
summer.peak.hr21  18732.6     4478.4      92.7  374.4 648.9 942.3 1511.1
summer.peak.avdy  17822.7     4278.6      89.1  357.3 567   871.2 1577.7

summer.average.hr9      15313 3702.24     80.64 299.52      482.4 738
      1316.88
summer.average.avnt     11900 2673.36     55.44 272.16      329.04
      623.52      874.08
summer.average.hr19     16046 3822.48     84.96 299.52      444.96      738
      1357.2
summer.average.hr20     15586 3720.24     82.08 299.52      482.4 768.96
      1268.64
summer.average.hr21     14986 3582.72     74.16 299.52      519.12
      753.84      1208.88
summer.average.avdy     14258 3422.88     71.28 285.84      453.6 696.96
      1262.16

summer.offpeak.hr9      13399 3239.46     70.56 262.08      422.1 645.75
      1152.27
summer.offpeak.avnt     10413 2339.19     48.51 238.14      287.91
      545.58      764.82
summer.offpeak.hr19     14040 3344.67     74.34 262.08      389.34
      645.75      1187.55
summer.offpeak.hr20     13638 3255.21     71.82 262.08      422.1 672.84
      1110.06
summer.offpeak.hr21     13112 3134.88     64.89 262.08      454.23
      659.61      1057.77
summer.offpeak.avdy     12475 2995.02     62.37 250.11      396.9 609.84
      1104.39
;

$ontext
```

```
******************************   Section  5
**********************************


*-------------------- 24 hour demand data ----------------------
SET
        th      Hours index        / hr1*hr24/;
scalar    thT     number of hours in a day /24/;

Table PeakD(ty,z)       {peak demand for each region in each year}
     Ang Bot Les Mwi NMz SMz Nam   NSA  SSA Swz Taz DRC  Zam  Zim
yr1  215 209  74 185  85 101 298 22287 5309 118 416 721 1068 1885
;

******************************   Section  6
**********************************

Table   july2497(th,z) Hourly System load on July 24 1997
** OK   cooked  **      **      cooked  0       0       0
      Ang     Bot     Les     Mwi     NMz     SMz     Nam
hr1   185     136     43      148     35      65      205
hr2   185     137     42      148     33      60      185
hr3   185     138     41      148     39      57      183
hr4   185     141     40      148     47      56      183
hr5   185     144     40      148     52      56      186
hr6   185     156     43      148     57      56      195
hr7   215     176     48      148     60      61      217
hr8   215     193     62      185     77      65      266
hr9   215     211     74      185     81      70      286
hr10  215     209     71      185     78      76      292
hr11  215     201     68      185     80      76      288
hr12  215     202     63      185     85      76      278
hr13  185     189     64      148     71      75      276
hr14  185     180     59      148     70      71      263
hr15  185     177     57      148     76      67      268
hr16  185     176     56      148     76      66      271
hr17  185     170     56      148     75      66      274
hr18  185     167     56      148     64      76      266
hr19  215     189     66      185     53      101     271
hr20  215     191     71      185     69      95      298
hr21  215     189     66      185     64      91      296
hr22  215     181     61      148     58      85      282
hr23  185     174     57      148     59      72      253
hr24  185     169     50      148     57      64      238

******************************   Section  7
**********************************


* OK    **      **      **      cooked  0       **      **
+     NSA         SSA   Swz    Taz    DRC    Zam    Zim
hr1   16246       3667  71     378    412    844    1150
hr2   16011       3534  70     378    433    855    1137
hr3   15901       3501  71     378    453    855    1134
hr4   15853       3474  72     378    453    855    1149
hr5   16077       3523  76     378    464    887    1224
hr6   17493       3863  96     378    464    897    1389
```

```
hr7   20087       4597  114   416   618   961   1617
hr8   21387       5143  114   416   644   983   1753
hr9   21269       5142  112   416   670   1025  1829
hr10  20756       4985  102   416   670   1004  1841
hr11  20233       4874  102   378   675   972   1825
hr12  19737       4741  101   378   675   961   1792
hr13  19322       4690  97    378   675   983   1787
hr14  19083       4617  93    378   670   940   1729
hr15  18887       4614  83    378   618   940   1730
hr16  18933       4637  88    378   567   940   1766
hr17  19214       4682  90    416   515   951   1799
hr18  20642       4933  112   416   567   961   1880
hr19  22287       5309  118   416   618   1025  1885
hr20  21618       5167  114   416   670   1068  1762
hr21  20814       4976  103   416   721   1047  1679
hr22  19349       4532  95    416   670   1015  1512
hr23  17862       4224  84    378   567   887   1334
hr24  16789       3918  77    378   412   844   1194
;

******************************   Section  8
**********************************

$offtext

(data file, section 5)
Parameter DLC(z)   {domestic loss coefficient for each region}
/Ang    1.05
 Bot    1.00
 Les    1.05
 Mwi    1.05
 NMz    1.05
 SMz    1.05
 Nam    1.05
 NSA    1.05
 SSA    1.05
 Swz    1.05
 Taz    1.05
 DRC    1.05
 Zam    1.05
 Zim    1.05
 /;

(reserve file, section 12)
Table LM(z,th)
      hr9   avnt  hr19  hr20  hr21  avdy
Ang     0   0     0     0     0     0
Bot     0
Les     0
Mwi     0
NMz     0
SMz     0
Nam     0
NSA     0
SSA     0
Swz     0
Taz     0
```

DRC 0
Zam 0
Zim 0
;

(lines file, section 3)
Table PFOloss(z,zp) {International transmission loss coefficient}

	Bot	Les	Mwi	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Bot	0	0	0	0	0	0	0.035	0	0	0	0	0	0.035
Les	0	0	0	0	0	0	0.05	0	0	0	0	0	0
Mwi	0	0	0	0	0	0	0	0	0	0	0	0	0
Nmz	0	0	0	0	0.9	0	0.10	0	0	0	0	0	0.03
Smz	0	0	0	0.9	0	0	0.03	0	0.015	0	0	0	0
Nam	0	0	0	0	0	0	0	0.07	0	0	0	0	0
NSA	0.035	0.05	0	0.10	0.03	0	0	0.03	0.02	0	0	0	0
SSA	0	0	0	0	0	0.07	0.03	0	0	0	0	0	0
Swz	0	0	0	0	0.015	0	0.02	0	0	0	0	0	0
Taz	0	0	0	0	0	0	0	0	0	0	0	0.06	0
DRC	0	0	0	0	0	0	0	0	0	0	0	0.01	0
Zam	0	0	0	0	0	0	0	0	0	0.06	0.01	0	0.0
Zim	0.035	0	0	0.03	0	0	0	0	0	0	0	0.0	0

* Updated at SAPP workshop Capetown [July 06]

(lines file, section 5)
Table PFNloss(z,zp) {transmission loss factor [0-1]}

	Ang	Bot	Mwi	Les	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Ang	0	0	0	0	0	0	0.14	0	0	0	0	0.02	0	0
Bot	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Les	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mwi	0	0	0	0	0.03	0	0	0	0	0	0	0	0.04	0
Nmz	0	0	0.03	0	0	0.10	0	0	0	0	0	0	0	0
Smz	0	0	0	0	0.10	0	0	0	0	0	0	0	0	0
Nam	0.14	0	0	0	0	0	0	0	0.02	0	0	0	0	0
NSA	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSA	0	0	0	0	0	0	0.02	0	0	0	0	0	0	0
Swz	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taz	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRC	0.02	0	0	0	0	0	0	0	0	0	0	0	0.01	0
Zam	0	0	0.04	0	0	0	0	0	0	0	0	0.01	0	0
Zim	0	0	0	0	0	0	0	0	0	0	0	0	0	0

* DRC-ANG-NAM, NMZ-SMZ need to be updated

```
(hydro file, section 9)
Parameter PSOloss; PSOloss = 0.3;

(hydro file, section 9)
Parameter PSNloss(phn); PSNloss(phn) = 0.3;
```

Appendix 1B to Chapter 4 - Adding DSM

At the present time, the model only allows pre-specified levels of "DSM" programs to enter the problem as an aggregate subtraction from the hourly demand drivers of the model. The user can then experiment with the impact various pre-specified mixes of "DSM" programs can have on the cost of SAPP generation, and compare such cost reductions with the increased costs of implementing the various mixes of programs to see which are cost-effective.

The model could be easily modified to explicitly trade off "DSM" programs against supply side programs to produce a true least cost SAPP plan in the following way.

Step 1: Identify the range of "DSM" projects which are possible for SAPP members to implement in sufficient detail to allow comparison with comparable supply side programs.

example: "Replace all motors over 10 HP in RSA with hi∈ motors: result: reduce all hourly demands by 400 MW; program cost of 400 million dollars (cash rebates to hi∈ motor purchasers)"

Step 2: Define a "DSM" program level variable bounded between 0 and 1, which allows full or partial implementation of the project.

example: let "HI∈MOT" be the decision variable for the motor replacement program described above - $0 \leq$ HI∈MOT≤ 1, i.e., when "HI∈MOT" = .5, cost is $(400 \times 10^6)(.5)$, MW reduction is (400 MW)(.5).

Step 3: Create the relationship between base demand in hour "i", the levels chosen for the "DSM" programs identified, and actual demand in hour "i"

example: actual demand in hour "i" would equal Base Demand without "DSM" program in "i" minus (HI∈Mot)(400). e.g., if the hi∈ motor plan is fully implemented, ["HI∈MOT = 1"] then actual demand is Base demand in "i" - 400 MW for all "i"; if half is implemented, ["HI∈MOT = .5"] actual demand is Base demand in "i" - 200 MW, etc...

Step 4: Enter the levelized cost of the "DSM" program in the objective function;

example: $(400 \times 10^6)(\text{HI} \in \text{MOT})(\text{crf})$

A general "stand alone" version of the trade off between demand and supply side options can be formulated in the following way. If "x_j" is the decision variable, $0 \leq x_j \leq 1$, which indicates what fraction of program "j" will be undertaken, "$\bar{\$}_j$" the cost of the program if "j" fully undertaken ("x_j" = 1), "$\bar{a}_{\tau j}$" the reduction in demand in hour "τ" of a representative day in a given year if program "j" were fully undertaken ("x_j" = 1), "$\overline{\text{Dyr}(\tau)}$" the base demand in hour "τ" in that representative day, without any DSM ("x_j" = 0 for all "j") "Dyr(τ)" the remaining portion of the demand met by generation during hour "τ" of the representative day after "DSM", "$\bar{c}(\tau)$" the generation cost/MW of meeting demand by generation in hour "τ", in that day and K is scalar which scales up the typical day into a year, the problem of determining the least cost mix of generation and DSM in that year which satisfies final demand can be stated as:

$$\min_{x_j, \text{Dyr}(\tau)} \sum_{j=1}^{n} (\overline{\text{crf}})(\$_j) x_j + \sum_{\tau=1}^{24} K\bar{c}(\tau)\text{Dyr}(\tau)$$

$$\text{sit.} \quad \text{Dyr}(\tau) + \sum_{j=1}^{n} \bar{a}_{\tau j} x_j = \overline{\text{Dyr}(\tau)}, = 1, 2, \ldots 24$$

$$0 \leq x_j \leq 1 \text{ or } x_j = \begin{Bmatrix} 1 \\ 0 \end{Bmatrix}$$

The above "stand alone" model is a static model with regards to years - it says what the options are <u>this</u> <u>year</u> to implement "DSM" programs, what is the impact <u>this</u> <u>year</u> on costs (through the levelized capital cost) and <u>this</u> <u>year</u> on demands of actions taken <u>this</u> <u>year</u>.

The model can be made dynamic in the following way;

- Allow "$x_j(ty)$" to be the fraction of DSM program "x_j" implemented in year "ty".

Then it must be true that:

$$\sum_{ty=1}^{T} x_j(ty) \le 1,\ \ x_j(ty) \ge 0 \ \text{ or } \ x_j(ty) = \begin{Bmatrix}1\\0\end{Bmatrix}$$

e.g. no more than the full program can be implemented over the planning horizon "T".

- Letting "$Dyr(\tau,ty)$" be demand met by DSM in hour "τ" in the representative day in year "ty", and "$\overline{Dyr(\tau,ty)}$" be demand in {"τ,ty"} without any "DSM", the load balance equation in year "ty" becomes;

$$Dyr(\tau,ty) + \sum_{j=1}^{n} \bar{a}_{\tau j} \sum_{\alpha=1}^{ty} x_j(\alpha) = \overline{Dyr(\tau,ty)}$$

$$\tau = 1,2,\ldots 24$$

$$ty = 1,2,\ldots T$$

e.g. demand in "ty" in hour "τ" is reduced by the sum effect of all "DSM" programs implemented up to the year 'ty", given by $\sum_{\alpha=1}^{ty} x_j(\alpha)$.

The objective function becomes;

$$\sum_{j=1}^{n} \sum_{ty=1}^{T} \left[\sum_{tya=ty}^{T} \frac{(crf)(\$_j)x_j(ty)}{(1+disc)^{tya}} + \sum_{\tau=1}^{24} \frac{K\bar{c}(\tau,ty)Dyr(\tau,ty)}{(1+disc)^{ty}} \right]$$

The first term inside the bracket is the present value of the stream of levelized capital charges arising from "DSM" program "x_j" in year "ty" and continuing to the end of the horizon. The second is the cost of satisfying residual demand by generation in year "ty". The terms in brackets need to be summed over all "ty", and also over all "n" "DSM" programs.

The “stand alone” model can be incorporated into the full model by simply entering the expression

$$\sum_{j=1}^{n} \bar{a}_{\tau j}\left[\sum_{\alpha=1}^{ty} x_j(\alpha)\right]$$

on the supply side of the demand equation as an alternative to the demand side options, and entering

$$\sum_{ty=1}^{T}\ \sum_{j=1}^{n}\ \sum_{tya=ty}^{T} \frac{(crf)(\$_j)x_j(ty)}{(1+\text{disc})^{tya}}$$

in the objective function, and let the model decide on the best mix of demand and supply side options.

Appendix 2 to Chapter 4
(Capacity Constraint Module)

Old Thermal Tables, Section 2a

```
(thermal file, section 13)
Table   PGOinit(z,i)    current capacity for old thermo plants
      Stat1 Stat2 Stat3 Stat4 Stat5 Stat6
Ang   114
Bot   118
Les   1.8
Mwi   0
NMz   12
SMz   0
Nam   108     24
NSA   3510    1320    3450    1900    3840    2700
SSA   1840
Swz   9
Taz   112
DRC   37
Zam   80
Zim   956   80      70      120

+       Stat7   Stat8   Stat9   Stat10
NSA     3558    1836    3690    3450

(thermal file, section 4)

Table   PGOexpstep(z,i)    expansion step size for old thermo plants units
     Stat1  Stat2  Stat3  Stat4  Stat5  Stat6
Ang  50
Bot  25
Les  0.4
Mwi  4
NMz  3
SMz  15
Nam  25     6
NSA  850    320    850     450    950   650
SSA  450
Swz  2
Taz  45
DRC  0
Zam  20
Zim  240    20     15     30

+     Stat7   Stat8   Stat9   Stat10
NSA   850     450     900     850

(thermal file, section 14)
Table   PGOmax(z,i)     max possible MW addition to old thermo plants
       Stat1   Stat2   Stat3   Stat4   Stat5   Stat6
Ang     0
Bot     0
Les     0
Mwi     0
NMz     0
SMz     0
```

```
Nam     0
NSA     0
SSA     0
Swz     0
Taz     0
DRC     0
Zam     0
Zim     0

+       Stat7   Stat8   Stat9   Stat10
NSA     0
;
```

(gms file, section 2)

```
Scalar DecayPGO         decay rate of old thermo      /0.001/;
```

(reserve file, section 2)

```
Table FORPGO(z,i)  {force outage rate for old thermo units}
      Stat1   Stat2   Stat3   Stat4   Stat5   Stat6
Ang     0.04
Bot     0.04
Les     0.04
Mwi     0.04
NMz     0.04
SMz     0.04
Nam     0.04    0.04
NSA     0.04    0.04    0.04    0.04    0.04    0.04
SSA     0.04
Swz     0.04
Taz     0.04
DRC     0.04
Zam     0.04
Zim     0.04    0.04    0.04    0.04

+       Stat7   Stat8   Stat9   Stat10
NSA     0.04    0.04    0.04    0.04
;
```

(reserve file, section 10)

```
Table UFORPGO(z,i)      {unforce outage rate for old thermo plants}
       Stat1   Stat2   Stat3   Stat4   Stat5   Stat6
Ang     0.10
Bot     0.10
Les     0.10
Mwi     0.10
NMz     0.10
SMz     0.10
Nam     0.10    0.10
NSA     0.10    0.10    0.10    0.10    0.10    0.10
SSA     0.10
Swz     0.10
Taz     0.10
DRC     0.10
Zam     0.10
Zim     0.10    0.10    0.10    0.10

+       Stat7   Stat8   Stat9   Stat10
```

```
NSA     0.10    0.10    0.10    0.10
;
```

Old Hydro Tables, Section 2b

```
(hydro file, section 4)
Table   HOinit(z,ih)  {Existing hydro initial capacity (MW)}
     Stat1   Stat2  Stat3  Stat4  Stat5
Ang  121     56     37.3   37.3   37.3
Les  24
Mwi  214
NMz  2075    81
SMz  16.6
Nam  240
NSA  400     1000
SSA  320     220
Swz  20      15     6.5
DRC  1775    248    108    68.04  42
Taz  204     80     66     21     8
Zam  600     900    100
Zim  666
;

(hydro file, section 5)
Table HOexpstep(z,ih) expansion step for existing hydro {HOVmax/5}
      Stat1   Stat2   Stat3   Stat4   Stat5
Ang     45   {Cambambe Extension}
NMz     1240  {Cahorra Bassa Extension}
Zam     150   {Kariba North Extension, only if Batoka}
Zim     150   {Kariba South Extension, only if Batoka}
;
```

(hydro file, section 4)

```
Table HOVmax(z,ih) Max possible expansion on existing hydro
      Stat1   Stat2   Stat3   Stat4   Stat5
Ang     90  {Cambambe Extension}
NMz     1240  {Cahorra Bassa Extension}
Zam     300  {Kariba North Extension, only if Batoka}
Zim     300  {Kariba South Extension, only if Batoka}
;

(gms file, section 2)
Scalar DecayHO    decay rate of old hydro       /0.001/;

(hydro file, section 8)
Table   FORoh(z,ih)  {Existing hydro forced outage rate}
      Stat1 Stat2 Stat3 Stat4 Stat5
Ang   0.028 0.028 0.028
Mwi   0.028
NMz   0.028 0.028
Nam   0.028
SSA   0.028 0.028
Swz   0.028
DRC   0.028 0.028 0.028 0.028 0.028
Taz   0.028 0.028
Zam   0.028 0.028 0.028
Zim   0.028
```

```
***----------- Energy (MWh) limit for new hydros ------------- -------------

(hydro file, section 5)
Parameter HROmwh(ts,z,ih); {Seasonal MWh cap of existing Run of River}
HROmwh(ts,z,ih) = HOinit(z,ih)*(tdT*thT);

*@@@ Old Dams MWh capacity multiplier @@@@ [Zyu june 1 '98] @@@@@@@@@@@@@
Parameter fdamO(z,ih,ts);
fdamO(z,ih,ts)$(ord(ts) EQ 1) = 1.6; {summer season all ROR hydros}
fdamO(z,ih,ts)$(ord(ts) EQ 2) = 0.3; {winter season}

fdamO('Nmz','stat1','summer') = 1.8;  {Cahorra Bassa existing}
fdamO('Nmz','stat1','winter') = 0.8;

fdamO('DRC','stat1','summer') = 20; {Inga existing}
fdamO('DRC','stat1','winter') = 12;

parameter fdrought(ty) (uncertain file)
                       {reduced water flow during drought; 1 = normal <1 is
dry}
/yr2    1
 yr3    1
 yr4    1
 yr5    1
/;
```

New Thermal Tables, Section 2c

Combustion Turbines

```
(thermal file, section 5)
Table   NTexpstep(z,ni)    {expansion step size for new gas turbine plants}
     NS1  NS2  NS3
Ang  50   50   50
Bot  50   50   50
Les  50   50   50
SMz  50   50   50
Nam  50   50   50
NSA  250  50   50
SSA  50   50   50
Taz  40   10   50
Zim  50   50   50
;

(thermal file, section 14)
Table PGNTmax(z,ni)
     NS1   NS2   NS3
Ang  450   450   450
Bot  450   450   450
Les  450   450   450
Mwi  450   450   450
NMz  450   450   450
SMz  450   450   450
Nam  450   450   450
NSA  1000  450   450
SSA  450   450   450
Swz  450   450   450
```

```
Taz  40    100   450
DRC  450   450   450
Zam  450   450   450
Zim  450   450   450
```

(gms file, section 2)

```
Scalar DecayNT          decay rate of gas turbine     /0.001/;
```

(reserve file, section 2)

```
Table FORNT(ty,z,ni)
      NS1   NS2   NS3
Ang   0.104 0.104 0.104
Bot   0.104 0.104 0.104
Les   0.104 0.104 0.104
Mwi   0.104 0.104 0.104
NMz   0.104 0.104 0.104
SMz   0.104 0.104 0.104
Nam   0.104 0.104 0.104
NSA   0.104 0.104 0.104
SSA   0.104 0.104 0.104
Swz   0.104 0.104 0.104
Taz   0.104 0.104 0.104
DRC   0.104 0.104 0.104
Zam   0.104 0.104 0.104
Zim   0.104 0.104 0.104
;
```

(reserve file, section 5)

```
Table UFORNT(z,ni)
      NS1   NS2   NS3
Ang   0.07  0.07  0.07
Bot   0.07  0.07  0.07
Les   0.07  0.07  0.07
Mwi   0.07  0.07  0.07
NMz   0.07  0.07  0.07
SMz   0.07  0.07  0.07
Nam   0.07  0.07  0.07
NSA   0.07  0.07  0.07
SSA   0.07  0.07  0.07
Swz   0.07  0.07  0.07
Taz   0.07  0.07  0.07
DRC   0.07  0.07  0.07
Zam   0.07  0.07  0.07
Zim   0.07  0.07  0.07
;
```

Small Coal

(thermal file, section 6)

```
Table   NSCexpstep(z,ni) {expansion step size for new small coal plants}
      NS1   NS2   NS3   NS4   NS5
Ang   300   300
Bot   120   300
Les   300   300
SMz   250   300
Nam   300   300
NSA   90    190   110   190   100
```

```
SSA   300   300
Taz   300   300
Zim   84    300
;

(thermal file, section 15)
Table PGNSCmax(z,ni)
     NS1  NS2  NS3  NS4  NS5
Ang  600  600
Bot  240  600
Les  600  600
Mwi  600  600
NMz  750  600
SMz  600  600
Nam  600  600
NSA  450  1140  440 1520 1000
SSA  600  600
Swz  600  600
Taz  600  600
DRC  600  600
Zam  600  600
Zim  84   600
;

(gms file, section 2)
Scalar DecayNSC         decay rate of small coal      /0.001/;

(reserve file, section 4)
Table FORNSC(z,ni)
      NS1          NS2
Ang   0.046        0.046
Bot   0.046        0.046
Les   0.046        0.046
Mwi   0.046        0.046
NMz   0.046        0.046
SMz   0.046        0.046
Nam   0.046        0.046
NSA   0.046        0.046
SSA   0.046        0.046
Swz   0.046        0.046
Taz   0.046        0.046
DRC   0.046        0.046
Zam   0.046        0.046
Zim   0.046        0.046
;

(reserve file, section 7)
Table UFORNSC(z,ni)
      NS1          NS2
Ang   0.111        0.111
Bot   0.111        0.111
Les   0.111        0.111
Mwi   0.111        0.111
NMz   0.111        0.111
SMz   0.111        0.111
Nam   0.111        0.111
NSA   0.111        0.111
```

```
SSA   0.111       0.111
Swz   0.111       0.111
Taz   0.111       0.111
DRC   0.111       0.111
Zam   0.111       0.111
Zim   0.111       0.111
;
```

Combined Cycle

```
(thermal file, section 1)
Table       PGNCCinit(z,ni)         {initial capacity of new combined-cycle
plants}
     NS1  NS2  NS3
Ang  250  250  250
Bot  250  250  250
Les  250  250  250
Mwi  250  250  250
NMz  250  250  250
SMz  250  250  250
Nam  750  250  250
NSA  250  250  250
SSA  250  250  250
Swz  250  250  250
Taz  250  250  250
DRC  250  250  250
Zam  250  250  250
Zim  250  250  250

(thermal file, section 5)
Table   NCCexpstep(z,ni) {expansion step size for combined cycle plants
units}
      NS1   NS2   NS3
Ang   250   250   250
Bot   250   250   250
Les   250   250   250
SMz   250   250   250
Nam   250   250   250
NSA   250   250   250
SSA   250   250   250
Taz   250   250   250
Zim   250   250   250
;

(thermal file, section 15)
Table PGNCCmax(z,ni)
      NS1   NS2   NS3
Ang   750   750   750
Bot   750   750   750
Les   750   750   750
Mwi   750   750   750
NMz   750   750   750
SMz   750   750   750
Nam   0     750   750
NSA   750   750   750
SSA   750   750   750
Swz   750   750   750
```

```
Taz   750   750   750
DRC   750   750   750
Zam   750   750   750
Zim   750   750   750
;
```

(gms file, section 2)

Scalar DecayNCC   decay rate of combined cycle /0.001/;

(reserve file, section 3)

```
Table FORNCC(z,ni)
      NS1   NS2   NS3
Ang   0.104 0.104 0.104
Bot   0.104 0.104 0.104
Les   0.104 0.104 0.104
Mwi   0.104 0.104 0.104
NMz   0.104 0.104 0.104
SMz   0.104 0.104 0.104
Nam   0.104 0.104 0.104
NSA   0.104 0.104 0.104
SSA   0.104 0.104 0.104
Swz   0.104 0.104 0.104
Taz   0.104 0.104 0.104
DRC   0.104 0.104 0.104
Zam   0.104 0.104 0.104
Zim   0.104 0.104 0.104
;
```

(reserve file, section 6)

```
Table UFORNCC(z,ni)
      NS1   NS2   NS3
Ang   0.07  0.07  0.07
Bot   0.07  0.07  0.07
Les   0.07  0.07  0.07
Mwi   0.07  0.07  0.07
NMz   0.07  0.07  0.07
SMz   0.07  0.07  0.07
Nam   0.07  0.07  0.07
NSA   0.07  0.07  0.07
SSA   0.07  0.07  0.07
Swz   0.07  0.07  0.07
Taz   0.07  0.07  0.07
DRC   0.07  0.07  0.07
Zam   0.07  0.07  0.07
Zim   0.07  0.07  0.07
;
```

Large Coal

(thermal file, section 1)

```
Table      PGNLCinit(z,ni)        {initial capacity of new lagre coal
plants}
     NS1  NS2  NS3  NS4  NS5  NS6  NS7  NS8
Ang  500  500
Bot  500  500
Les  500  500
Mwi  500  500
```

```
NMz  500  500
SMz  500  500
Nam  500  500
NSA  659  959  659  659  659  659  659  659
SSA  1000 659  659  659
Swz  500  500
Taz  500  500
DRC  500  500
Zam  500  500
Zim  500  500
```

```
(thermal file, section 6)
Table   NLCexpstep(z,ni)  {expansion step size for new large coal plants}
     NS1  NS2  NS3  NS4  NS5  NS6  NS7  NS8
Ang  500  500
Bot  500  500
Les  500  500
SMz  500  500
Nam  500  500
NSA  659  659  659  659  659  659  659  659
SSA  500  500  500  500
Taz  500  500
Zim  500  500
 ;
```

```
(thermal file, section 16)
Table PGNLCmax(z,ni){max addition to LC}
     NS1   NS2   NS3   NS4   NS5   NS6   NS7   NS8
Ang  4500  4500
Bot  4500  4500
Les  4500  4500
Mwi  4500  4500
NMz  4500  4500
SMz  4500  4500
Nam  4500  4500
NSA  3295  3295  3295  3295  3295  3295  3295  3295
SSA  4500  3295  3295  3295
Swz  4500  4500
Taz  4500  4500
DRC  4500  4500
Zam  4500  4500
Zim  4500  4500
;
```

(gms file, section 2)

```
Scalar DecayNLC         decay rate of large coal      /0.001/;
```

```
(reserve file, section 5)
Table FORNLC(z,ni)
      NS1   NS2   NS3   NS4   NS5   NS6   NS7   NS8
Ang   0.047 0.047 0.047
Bot   0.047 0.047 0.047
Les   0.047 0.047 0.047
Mwi   0.047 0.047 0.047
NMz   0.047 0.047 0.047
SMz   0.047 0.047 0.047
Nam   0.047 0.047 0.047
```

```
NSA   0.047 0.047 0.047 0.047 0.047 0.047 0.047 0.047
SSA   0.047 0.047 0.047
Swz   0.047 0.047 0.047
Taz   0.047 0.047 0.047
DRC   0.047 0.047 0.047
Zam   0.047 0.047 0.047
Zim   0.047 0.047 0.047
;

(reserve file, section 7)
Table UFORNLC(z,ni)
      NS1   NS2   NS3   NS4   NS5   NS6   NS7   NS8
Ang   0.111 0.111
Bot   0.111 0.111
Les   0.111 0.111
Mwi   0.111 0.111
NMz   0.111 0.111
SMz   0.111 0.111
Nam   0.111 0.111
NSA   0.111 0.111 0.111 0.111 0.111 0.111 0.111 0.111
SSA   0.111 0.111
Swz   0.111 0.111
Taz   0.111 0.111
DRC   0.111 0.111
Zam   0.111 0.111
Zim   0.111 0.111
;
```

New Hydro Tables

```
(hydro dile, section 1)
set nh new hydro index  /newh1*newh4/

Table HNinit(z,nh) Initial MW capacity of New hydro Stations
    newh1                          newh2               newh3              newh4

Ang 130    {CapandaII}             0                   0                  0
Les 0     {Muela }                 0                   0                  0
Mwi 32     {Kapichiri I & II}      45                  125 {Lower fufu}  35
Nmz 400   {Mepandua Uncua }        0                   0                  0
Nam 360    {Epupua/Kunene River }  0                   0                  0
Taz 60    {Lower Kihansi }         74 {Rumakali}       160 {Mpanga}       0
DRC 4750   {Grand Inga I & 2}      4750                4750               4750
Zam 40     {itezhi-teshi}          150 {Kafue Gorge}   200 {Batoka N}     0
                                   {water: 1260e6 m-cubed/hr }
Zim 200    {Batoka S}              300 {Gokwe N}       0 {Kariba}         0

(hydro file, section 3)
Table HNexpstep(z,nh) Expansion step for new hydro stations
    newh1                            newh2   newh3   newh4
Ang 130     {Capanda}
Les 24     {Muela}
Mwi 32     {Kapichiri II, Shire}   45      63      35
Nmz 400
Taz 60                              74      89.5
DRC 5250                            5250    5250    5250
Zam 37                              150     200
```

```
Zim 200                         300

(hydro file, section 2)
Table HNVmax(z,nh) Max possible MW addition to a new hydro station
    newh1                       newh2  newh3  newh4
Ang 130    {Capanda}
Les 48     {Muela}
Mwi 32     {Kapichiri II, Shire}  45     63     35
Nmz 1600
Taz 120                         148    368.5
DRC
Zam 37                          450    600
Zim 600                         900

(gms file, section 2)
Scalar DecayHN          decay rate of new hydro       /0.001/;

(hydro file, section 8)
Table FORnh(z,nh)       {forced outage rate for new hydro}
     newh1  newh2  newh3  newh4
Ang  0.028  0.028  0.028  0.028
Bot  0.028  0.028  0.028  0.028
Les  0.028  0.028  0.028  0.028
Mwi  0.028  0.028  0.028  0.028
NMz  0.028  0.028  0.028  0.028
SMz  0.028  0.028  0.028  0.028
Nam  0.028  0.028  0.028  0.028
NSA  0.028  0.028  0.028  0.028
SSA  0.028  0.028  0.028  0.028
Swz  0.028  0.028  0.028  0.028
Taz  0.028  0.028  0.028  0.028
DRC  0.028  0.028  0.028  0.028
Zam  0.028  0.028  0.028  0.028
Zim  0.028  0.028  0.028  0.028

***----------- Energy (MWh) limit for new hydros ------------- -------------

(hydro file, section 3)
*@@@ New Dams MWh capacity multiplier @@@@ [Zyu june 1 '98] @@@@@@@@@
Parameter fdamN(z,nh,ts);
fdamN(z,nh,ts)$(ord(ts) EQ 1) = 1.6; {summer season}
fdamN(z,nh,ts)$(ord(ts) EQ 2) = 0.3; {winter season}

fdamN('Nmz','newh1',ts)$(ord(ts) EQ 1) = 1.8; {summer season Mapenda Uncua}
fdamN('Nmz','newh1',ts)$(ord(ts) EQ 2) = 0.9; {winter season Mapenda Uncua}

fdamN('DRC','newh1',ts)$(ord(ts) EQ 1) = 20; {summer season Inga}
fdamN('DRC','newh1',ts)$(ord(ts) EQ 2) = 12; {winter season Inga}

Parameter HDNmwh(z,nh); {annual MWh capacity of new Dam}
HDNmwh(z,nh) = HNinit(z,nh)*(tdT*thT)*sum(ts,fdamN(z,nh,ts));

Parameter HRNmwh(ts,z,nh); {Seasonal MWh capacity of new Run of River}
HRNmwh(ts,z,nh) = HNinit(z,nh)*(tdT*thT);

(uncertain file)
```

```
parameter fdrought(ty) {reduced water flow during drought; 1 = normal <1 is
dry}
/yr2    1
 yr3    1
 yr4    1
 yr5    1
/;
```

Old Transmission Lines, Section 2e

(lines file, section 1)
Table   PFOinit(z,zp) Tie line capacities {MW}

	Ang	Bot	Les	Mwi	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Ang	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bot	0	0	0	0	0	0	0	850	0	0	0	0	0	650
Les	0	0	0	0	0	0	0	130	0	0	0	0	0	0
Mwi	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nmz	0	0	0	0	0	0	0	1800	0	0	0	0	0	550
Smz	0	0	0	0	0	0	0	1400	0	1200	0	0	0	0
Nam	0	0	0	0	0	0	0	0	700	0	0	0	40	0
NSA	0	850	130	0	2000	1400	0	0	3500	1400	0	0	0	650
SSA	0	0	0	0	0	0	700	3500	0	0	0	0	0	0
Swz	0	0	0	0	0	1200	0	1400	0	0	0	0	0	0
Taz	0	0	0	0	0	0	0	0	0	0	0	0	180	0
DRC	0	0	0	0	0	0	0	0	0	0	0	0	320	0
Zam	0	0	0	0	0	0	40	0	0	0	180	320	0	1200
Zim	0	650	0	0	550	0	0	650	0	0	0	0	1200	0

* Updated 12/6/98

(lines file, section 3)
Table PFOVmax(z,zp) {max possible MW addition to existing lines}
*??? model is very sensitive to this expansion ???????????????

	Ang	Bot	Les	Mwi	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Ang	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bot	0	0	0	0	0	0	0	3000	0	0	0	0	0	3000
Les	0	0	0	0	0	0	0	500	0	0	0	0	0	0
Mwi	0	0	0	0	700	0	0	0	0	0	0	0	500	0
Nmz	0	0	0	700	0	0	0	0	0	0	0	0	0	1000
Smz	0	0	0	0	0	0	0	3000	0	2000	0	0	0	0
Nam	0	0	0	0	0	0	0	0	18000	0	0	0	0	0
NSA	0	3000	500	0	3000	0	0	0	11000	0	0	0	0	18000
SSA	0	0	0	0	0	0	18000	11000	0	0	0	0	0	0
Swz	0	0	0	0	0	2000	0	2000	0	0	0	0	0	0
Taz	0	0	0	0	0	0	0	0	0	0	0	0	500	0
DRC	0	0	0	0	0	0	0	0	0	0	0	0	18000	0
Zam	0	0	0	500	0	0	0	0	0	0	500	18000	0	18000
Zim	0	3000	0	0	1000	0	0	18000	0	0	0	0	18000	0*

Updated 12/6/98

(gms file, section 2)
Scalar DecayPFO   decay rate of old lines   /0.000/;

(reserve file, section 9)
Table   FORICO(z,zp)   {forced outage rate for old transmission line}

	Bot	Les	Nmz	Smz	Nam	NSA	SSA	Swz	DRC	Zam	Zim
Bot	0	0	0	0	0	0	.014	0	0	0	.012

Les	0	0	0	0	0	.019	0	0	0	0	0
Nmz	0	0	0	.024	0	.024	0	0	0	0	.009
Smz	0	0	.024	0	0	.008	0	.004	0	0	.009
Nam	0	0	0	0	0	0	.008	0	0	0	0
NSA	0	.009	.024	.008	0	0	.005	0.1	0	0	.011
SSA	.014	0	0	0	.008	.005	0	0	0	0	0
Swz	0	0	0	.004	0	0.01	0	0	0	0	0
DRC	0	0	0	0	0	0	0	0	0	.009	0
Zam	0	0	0	0	0	0	0	0	.009	0	.002
Zim	.012	0	.009	.009	0	.011	0	0	0	.002	0

;

(lines file, section 3)

Table PFOloss(z,zp) {International transmission loss coefficient}

	Bot	Les	Mwi	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Bot	0	0	0	0	0	0	0.035	0	0	0	0	0	0.035
Les	0	0	0	0	0	0	0.05	0	0	0	0	0	0
Mwi	0	0	0	0	0	0	0	0	0	0	0	0	0
Nmz	0	0	0	0	0.9	0	0.10	0	0	0	0	0	0.03
Smz	0	0	0	0.9	0	0	0.03	0	0.015	0	0	0	0
Nam	0	0	0	0	0	0	0	0.07	0	0	0	0	0
NSA	0.035	0.05	0	0.10	0.03	0	0	0.03	0.02	0	0	0	0
SSA	0	0	0	0	0	0.07	0.03	0	0	0	0	0	0
Swz	0	0	0	0	0.015	0	0.02	0	0	0	0	0	0
Taz	0	0	0	0	0	0	0	0	0	0	0	0.06	0
DRC	0	0	0	0	0	0	0	0	0	0	0	0.01	0
Zam	0	0	0	0	0	0	0	0	0	0.06	0.01	0	0.0
Zim	0.035	0	0	0.03	0	0	0	0	0	0	0	0.0	0

* Updated at SAPP workshop Capetown [July 06]

New Transmission Lines, section 2f

(lines file, section 7)

Table PFNinit(z,zp) New Tie lines capacities (MW)

	Ang	Bot	Les	Mwi	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Ang	0	0	0	0	0	0	2000	0	0	0	0	0	0	0
Bot	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Les	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mwi	0	0	0	0	300	0	0	0	0	0	0	0	240	0
Nmz	0	0	0	300	0	1600	0	0	0	0	0	0	0	0
Smz	0	0	0	0	1600	0	0	0	0	0	0	0	0	0
Nam	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NSA	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSA	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Swz	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taz	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRC	2000	0	0	0	0	0	0	0	0	0	0	0	1000	0
Zam	0	0	0	240	0	0	0	0	0	0	0	1000	0	0
Zim	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(lines file, section 4)

Table PFNVmax(z,zp) New Tie lines max possible MW addition

	Ang	Bot	Les	Mwi	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Ang	0	0	0	0	0	0	18000	0	0	0	0	18000	0	0

```
Bot  0     0    0   0    0    0    0    0    0   0   0   0    0     0
Les  0     0    0   0    0    0    0    0    0   0   0   0    0     0
Mwi  0     0    0   0    0    0    0    0    0   0   0   0    0     0
Nmz  0     0    0   0    0    3000 0    0    0   0   0   0    0     0
Smz  0     0    0   0    3000 0    0    0    0   0   0   0    0     0
Nam  0     0    0   0    0    0    0    0    0   0   0   0    0     0
NSA  0     0    0   0    0    0    0    0    0   0   0   0    0     0
SSA  0     0    0   0    0    0    0    0    0   0   0   0    0     0
Swz  0     0    0   0    0    0    0    0    0   0   0   0    0     0
Taz  0     0    0   0    0    0    0    0    0   0   0   0    0     0
DRC  18000 0    0   0    0    0    0    0    0   0   0   0    18000 0
Zam  0     0    0   18000 0   0    0    0    0   0   0   0    0     0
Zim  0     0    0   0    0    0    0    0    0   0   0   0    0     0
;
(gms file, section 2)
Scalar DecayPFN         decay rate of new lines       /0.000/;

(reserve file, section 8)
Table FORICN(z,zp)  {forced outage rate for new transmission line}
    Ang  Bot  Mwi  Les  Nmz  Smz  Nam  NSA  SSA  Swz Taz  DRC  Zam  Zim
Ang 0    0    0    0    0    0    .013 0    0    0   0    .011 0    0
Bot 0    0    0    0    0    0    0    0    0    0   0    0    0    0
Les 0    0    0    0    0    0    0    0    0    0   0    0    0    0
Mwi 0    0    0    0    .004 0    0    0    0    0   0    0    .007 0
Nmz 0    0    .004 0    0    0    0    0    0    0   0    0    0    0
Smz 0    0    0    0    0    0    0    0.01 0    0.0 0    0    0    0
Nam .013 0    0    0    0    0    0    0    0    0   0    0    0    0
NSA 0    0    0    0    0.01 0    0    0    0    0   0    0    0    0
SSA 0    0    0    0    0    0    0    0    0    0   0    0    0    0
Swz 0    0    0    0    0.01 0    0    0    0    0   0    0    0    0
Taz 0    0    0    0    0    0    0    0    0    0   0    0    .013 0
DRC .011 0    0    0    0    0    0    0    0    0   0    0    0.01 0
Zam 0    0    .007 0    0    0    0    0    0    0   .013 0.01 0    0
Zim 0    0    0    0    0    0    0    0    0    0   0    0    0    0
;

(lines file, section 6)
Table   PFfix(z,zp)  fixtrade between region z and zp (MWh per day)
* Data from short-run model provided by Dr. Sparrow on June12th, 98
    Ang Bot  Mwi Les  Nmz Smz  Nam  NSA   SSA Swz  Taz DRC  Zam  Zim
Ang 0   0    0   0    0   0    0    0     0   0    0   0    0    0
Bot 0   0    0   0    0   0    0    0     0   0    0   0    0    0
Les 0   0    0   0    0   0    0    0     0   0    0   0    0    0
Mwi 0   0    0   0    0   0    0    0     0   0    0   0    0    0
Nmz 0   0    0   0    0   0    0    21600 0   0    0   0    0    10320
Smz 0   0    0   0    0   0    0    0     0   0    0   0    0    0
Nam 0   0    0   0    0   0    0    0     1E4 0    0   0    0    0
NSA 0   1800 0   1296 0   1536 2880 0     1E9 1800 0   0    0    3600
SSA 0   0    0   0    0   0    1E4  1E9   0   0    0   0    0    0
Swz 0   0    0   0    0   0    0    0     0   0    0   0    0    0
Taz 0   0    0   0    0   0    0    0     0   0    0   0    0    0
DRC 0   0    0   0    0   0    0    0     0   0    0   0    2400 0
Zam 0   0    0   0    0   0    0    0     0   0    0   0    0    2400
Zim 0   0    0   0    0   0    0    0     0   0    0   0    0    0

(lines file, section 5)
Table PFNloss(z,zp) {transmission loss factor [0-1]}
```

	Ang	Bot	Mwi	Les	Nmz	Smz	Nam	NSA	SSA	Swz	Taz	DRC	Zam	Zim
Ang	0	0	0	0	0	0	0.14	0	0	0	0	0.02	0	0
Bot	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Les	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mwi	0	0	0	0	0.03	0	0	0	0	0	0	0	0.04	0
Nmz	0	0	0.03	0	0	0.10	0	0	0	0	0	0	0	0
Smz	0	0	0	0	0.10	0	0	0	0	0	0	0	0	0
Nam	0.14	0	0	0	0	0	0	0	0.02	0	0	0	0	0
NSA	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSA	0	0	0	0	0	0	0.02	0	0	0	0	0	0	0
Swz	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taz	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRC	0.02	0	0	0	0	0	0	0	0	0	0	0	0.01	0
Zam	0	0	0.04	0	0	0	0	0	0	0	0	0.01	0	0
Zim	0	0	0	0	0	0	0	0	0	0	0	0	0	0

* DRC-ANG-NAM, NMZ-SMZ need to be updated

New Pumped Storage, Section 2g

```
(hydro file, sections 8 & 9)
Parameter PGPSOinit(z) {MW capacity of existing pumped hydro station}
      / SSA 1400 /;  {FTS 10.14.98}

Parameter HDPSOmwh(z) {Existing PS hydro reservoir volume (MWh) Capacity}
      / SSA 33600 /;  {HDPSOmwh(z)*24}

Scalar DecayPHO /0.001/;

Parameter PSNloss(phn); PSNloss(phn) = 0.3;

Table PHNinit(z,phn) {Initial MW capacity of proposed new Pumped Hydros}
            phn1  phn2  phn3  phn4
      SSA   999   999   999   1000 {BHB/JLP Oct 13 1998}

Scalar DecayPHN /0.001/;

Table HDPSNmwh(z,phn) {New PS hydro reservoir volume (MWh) Capacity}
            phn1  phn2  phn3  phn4
      SSA   23976 23976 23976 24000 {PHNinit(z,phn)*24}
```

Appendix 3 to Chapter 4
(Reliability)

```
(reserve file, section 12)
Parameter resthm(z)
/Ang  0.19
 Bot  0.19
 Les  0.19
 Mwi  0.19
 NMz  0.19
 SMz  0.19
 Nam  0.19
 NSA  0.19
 SSA  0.19
 Swz  0.19
 Taz  0.19
 DRC  0.19
 Zam  0.19
 Zim  0.19   /  ;

(reserve file, section 13)
Parameter Reshyd(z)
/Ang  0.10
 Bot  0.10
 Les  0.10
 Mwi  0.10
 NMz  0.10
 SMz  0.10
 Nam  0.10
 NSA  0.10
 SSA  0.10
 Swz  0.10
 Taz  0.10
 DRC  0.10
 Zam  0.10
 Zim  0.10    /   ;

(reserve file, section 13)
Parameter   resimp(z)
/Ang 0.25
 Bot 0.25
 Les 0.25
 Mwi 0.25
 Nmz 0.25
 Smz 0.25
 Nam 0.25
 NSA 0.25
 SSA 0.25
 Swz 0.25
 Taz 0.25
 DRC 0.25
 Zam 0.25
 Zim 0.25  /   ;

(reserve file, section 13)
Parameter   resexp(z)
/Ang 0.25
```

```
 Bot 0.25
 Les 0.25
 Mwi 0.25
 Nmz 0.25
 Smz 0.25
 Nam 0.25
 NSA 0.25
 SSA 0.25
 Swz 0.25
 Taz 0.25
 DRC 0.25
 Zam 0.25
 Zim 0.25  /   ;

(reserve file, section 11)
Parameter maxG(z)       {max generation unit capacity of each region}
/Ang      45
 Bot      29.5
 Les      0
 Mwi      2
 NMz      415
 SMz      5
 Nam      80
 NSA      800
 SSA      920
 Swz      10
 Taz      50
 DRC      178
 Zam      150
 Zim      200
/;

(reserve file, section 1)
Table AF(z,ty)          {autonomy factor}
      yr2   yr3   yr4   yr5
Ang   1     1     1     1
Bot   0.7   0.7   0.7   0.7
Les   0     0     0     0
Mwi   0.7   0.7   0.7   0.7
NMz   1     1     1     1
SMz   0.0   0.0   0.0   0.0
Nam   0.5   0.5   0.5   0.5
NSA   0.7   0.7   0.7   0.7
SSA   0     0     0     0
Swz   0     0     0     0
Taz   1     1     1     1
DRC   1     1     1     1
Zam   1     1     1     1
Zim   0.9   0.9   0.9   0.9
;
```

Appendix 4 to Chapter 4
(Objective Function)

Fuel and Operating Costs

Hydros and Unserved Energy

```
(data file, section 1)
Scalar UEcost   /5000/;          {cost of unserved energy}

(hydro file, section 1)
Scalar wcost; {Opportunity cost of water $/MWh}
      wcost = 3.5;
```

Existing Thermal Plants

```
(thermal file, section 11)
Table   HRO(z,i)        {heat rate of old thermo plants set equal to one}
      Stat1   Stat2   Stat3   Stat4   Stat5   Stat6
Ang     1
Bot     1
Les     1
Mwi     1
NMz     1
SMz     1
Nam     1       1
NSA     1       1       1       1       1       1
SSA     1
Swz     1
Taz     1
DRC     1
Zam     1
Zim     1       1       1       1

+       Stat7   Stat8   Stat9   Stat10
NSA     1       1       1       1
;

(thermal file, section 7)
{the fuel costs of old plants is using dollar/MWh}
Table   fpO(z,i)        fuel costs of old thermo plants dollar per MWh
      Stat1 Stat2 Stat3 Stat4 Stat5 Stat6
Ang   1.3
Bot   5.71
Les   5
Mwi   4
NMz   3.1
SMz   4.1
Nam   28.9  31.9
NSA   4.73  7.04  4.05  3.87  4.35  3.85
SSA   3.36
Swz   52.1
Taz   77.03
DRC   6.0
Zam   100 {<-- is this right???}
Zim   3.7   6.4   6.38  6.4
```

```
+     Stat7 Stat8 Stat9 Stat10
NSA   4.03  2.67  3.93  3.9
;

(thermal file, section 9)
Table   fpescO(z,i) escalation rate of fuel costs of old thermo plants
      Stat1   Stat2   Stat3   Stat4   Stat5   Stat6
Ang     1.01
Bot     1.01
Les     1.01
Mwi     1.01
NMz     1.01
SMz     1.01
Nam     1.01     1.01
NSA     1.01     1.01   1.01    1.01    1.01    1.01
SSA     1.01
Swz     1.01
Taz     1.01
DRC     1.01
Zam     1.01
Zim     1.01    1.01    1.01    1.01

+       Stat7   Stat8   Stat9   Stat10
NSA     1.01    1.01    1.01    1.01
;

(thermal file, section 19)
Table   OMO(z,i)   O&M for old thermal plants
     Stat1 Stat2 Stat3 Stat4 Stat5 Stat6
Ang  0.89
Bot  0.89
Les  0.89
Mwi  0.89
NMz  0.89
SMz  0.89
Nam  0.89  0.89
NSA  0.89  0.89  0.89  0.89  0.89  0.89
SSA  0.89
Swz  0.89
Taz  0.89
DRC  0.89
Zam  0.89
Zim  0.89  0.89  0.89  0.89



+    Stat7 Stat8 Stat9 Stat10
NSA  0.89  0.89  0.89  0.89
```

Proposed New Thermal plants

```
(thermal file, section 11)
Table HRNT(z,ni)
      NS1   NS2   NS3
Ang   11.25 11.25 11.25
Bot   11.25 11.25 11.25
```

```
Les   11.25 11.25 11.25
Mwi   11.25 11.25 11.25
NMz   11.25 11.25 11.25
SMz   11.25 11.25 11.25
Nam   11.25 11.25 11.25
NSA   9.478 11.25 11.25
SSA   11.25 11.25 11.25
Swz   11.25 11.25 11.25
Taz   9.045 11.06 11.25
DRC   11.25 11.25 11.25
Zam   11.25 11.25 11.25
Zim   11.25 11.25 11.25
;

(themal file, section 12)
Table HRNCC(z,ni)
      NS1   NS2   NS3
Ang   7.49  7.49  7.49
Bot   7.49  7.49  7.49
Les   7.49  7.49  7.49
Mwi   7.49  7.49  7.49
NMz   7.49  7.49  7.49
SMz   7.49  7.49  7.49
Nam   7.49  7.49  7.49
NSA   7.49  7.49  7.49
SSA   7.49  7.49  7.49
Swz   7.49  7.49  7.49
Taz   7.49  7.49  7.49
DRC   7.49  7.49  7.49
Zam   7.49  7.49  7.49
Zim   7.49  7.49  7.49
;

(thermal file, section 12)
Table HRNLC(z,ni)
     NS1  NS2  NS3  NS4  NS5  NS6  NS7  NS8
Ang  9.8  9.80
Bot  9.8  9.80
Les  9.8  9.80
Mwi  9.8  9.80
NMz  9.8  9.80
SMz  9.8  9.80
Nam  9.8  9.80
NSA  9.89 9.89 9.89 9.89 9.89 9.89 9.89 9.89
SSA  9.8  9.80 9.8  9.8
Swz  9.8  9.80
Taz  9.8  9.80
DRC  9.8  9.80
Zam  9.8  9.80
Zim  9.8  9.80
;

(thermal file, section 13)
Table HRNSC(z,ni)
     NS1   NS2   NS3   NS4   NS5
Ang  9.80  9.80
Bot  9.80  9.80
```

```
Les  9.80  9.80
Mwi  9.80  9.80
NMz  9.80  9.80
SMz  9.80  9.80
Nam  9.80  9.80
NSA  12.88 12.19 12.88 12.19 7.58
SSA  9.80  9.80
Swz  9.80  9.80
Taz  9.80  9.80
DRC  9.80  9.80
Zam  9.80  9.80
Zim  9.80  9.57
;

(thermal file, section 7)
Table fpNT(z,ni) {fuel costs of new gas turbine cent/10000/BTU}
     NS1   NS2   NS3
Ang  2.4   2.4   2.4
Bot  4.0   4.0   4.0
Les  4.0   4.0   4.0
SMz  2.4   2.4   2.4
Nam  2.2   2.2   2.2
NSA  6.19  4.0   4.0
SSA  3.6   3.6   3.6
Swz  6.5   6.5   6.5
Taz  2.83  12.66 2.4
Zam  6.5   6.5   6.5
Zim  4.0   4.0   4.0
;

(thermal file, section 8)
Table fpNCC(z,ni) {fuel costs of new combined-cycle cent/10000/BTU}
      NS1   NS2   NS3
Ang   1.20  1.21  1.22
Bot   2.00  2.01  2.02
Les   2.00  2.01  2.02
SMz   1.20  1.21  1.22
Nam   1.10  1.11  1.12
NSA   2.00  2.01  2.02
SSA   1.80  1.81  1.82
Taz   1.20  1.21  1.22
Zim   2.00  2.01  2.02
;

(thermal file, section 8)
Table fpNSC(z,ni) {fuel costs of new small coal plants cent/10000/BTU}
     NS1  NS2  NS3  NS4  NS5
Ang  0.6  0.6
Bot  0.6  0.6
Les  0.6  0.6
SMz  0.6  0.6
Nam  0.6  0.6
NSA  0.6  0.6
SSA  0.4  0.6  0.47 0.48 0.45
Swz  0.8  0.8
Taz  0.6  0.6
Zam  0.8  0.8
```

```
Zim  0.4  0.36
;


(thermal file, section 8)
Table fpNLC(z,ni) {fuel costs of new large coal plants cent/10000/BTU}
     NS1   NS2   NS3   NS4   NS5   NS6   NS7   NS8
Ang  0.3   0.3
Bot  0.3   0.3
Les  0.3   0.3
SMz  0.3   0.3
Nam  0.3   0.3
NSA  0.41  0.41  0.41  0.41  0.41  0.41  0.41  0.41
SSA  0.64  0.6   0.6   0.6
Taz  0.3   0.3
Zim  0.3   0.3
;

(thermal file, section 9)
parameter fpescNT(z) escalation rate of fuel cost of new gas turbine
/Ang    1.01
 Bot    1.01
 Les    1.01
 SMz    1.01
 Nam    1.01
 NSA    1.01
 SSA    1.01
 Taz    1.01
 Zim    1.01
/;

(thermal file, section 10)
parameter fpescNCC(z) escalation rate of fuel cost of new combined cycle
/Ang    1.01
 Bot    1.01
 Les    1.01
 SMz    1.01
 Nam    1.01
 NSA    1.01
 SSA    1.01
 Taz    1.01
 Zim    1.01
/;

(thermal file, section 10)
parameter fpescNSC(z) escalation rate of fuel cost of new small coal
/Ang    1.01
 Bot    1.01
 Les    1.01
 SMz    1.01
 Nam    1.01
 NSA    1.01
 SSA    1.01
 Taz    1.01
 Zim    1.01
/;
```

```
(thermal file, section 10)
parameter fpescNLC(z) escalation rate of fuel cost of new large coal
/Ang    1.01
 Bot    1.01
 Les    1.01
 SMz    1.01
 Nam    1.01
 NSA    1.01
 SSA    1.01
 Taz    1.01
 Zim    1.01
/;

(thermal file, section 17)
Table OMT(z,ni)
     NS1  NS2  NS3
Ang  0.86 0.86 0.86
Bot  0.86 0.86 0.86
Les  0.86 0.86 0.86
Mwi  0.86 0.86 0.86
NMz  0.86 0.86 0.86
SMz  0.86 0.86 0.86
Nam  0.86 0.86 0.86
NSA  0.86 0.86 0.86
SSA  0.86 0.86 0.86
Swz  0.86 0.86 0.86
Taz  0.86 0.86 0.86
DRC  0.86 0.86 0.86
Zam  0.86 0.86 0.86
Zim  0.86 0.86 0.86
;

(thermal file, section 18)
Table OMCC(z,ni)
     NS1  NS2  NS3
Ang  0.82 0.82 0.82
Bot  0.82 0.82 0.82
Les  0.82 0.82 0.82
Mwi  0.82 0.82 0.82
NMz  0.82 0.82 0.82
SMz  0.82 0.82 0.82
Nam  0.82 0.82 0.82
NSA  0.82 0.82 0.82
SSA  0.82 0.82 0.82
Swz  0.82 0.82 0.82
Taz  0.82 0.82 0.82
DRC  0.82 0.82 0.82
Zam  0.82 0.82 0.82
Zim  0.82 0.82 0.82
;

(thermal file, section 18)
Table OMSC(z,ni)
     NS1  NS2  NS3  NS4  NS5
Ang  0.67 0.67 0.67 0.67 0.67
Bot  0.67 0.67 0.67 0.67 0.67
Les  0.67 0.67 0.67 0.67 0.67
```

```
Mwi  0.67 0.67 0.67 0.67 0.67
NMz  0.67 0.67 0.67 0.67 0.67
SMz  0.67 0.67 0.67 0.67 0.67
Nam  0.67 0.67 0.67 0.67 0.67
NSA  0.67 0.67 0.67 0.67 0.67
SSA  0.67 0.67 0.67 0.67 0.67
Swz  0.67 0.67 0.67 0.67 0.67
Taz  0.67 0.67 0.67 0.67 0.67
DRC  0.67 0.67 0.67 0.67 0.67
Zam  0.67 0.67 0.67 0.67 0.67
Zim  0.67 0.67 0.67 0.67 0.67
;
```

```
(thermal file, section 19)
Table OMLC(z,ni)
     NS1  NS2   NS3  NS4  NS5  NS6  NS7  NS8
Ang  0.7  0.7
Bot  0.7  0.7
Les  0.7  0.7
Mwi  0.7  0.7
NMz  0.7  0.7
SMz  0.7  0.7
Nam  0.7  0.7
NSA  0.68 0.236 4.12 5.41 0.64 0.6  0.6  0.6
SSA  0.2  0.6   0.6  0.6
Swz  0.7  0.7
Taz  0.7  0.7
DRC  0.7  0.7
Zam  0.7  0.7
Zim  0.7  0.7
;
```

New Equipment Costs

Existing Hydro plants

```
(hydro file, section 5)
Table HOVcost(z,ih) {Capital cost of additional Capacity $/MW old hydros}
      Stat1   Stat2   Stat3   Stat4   Stat5
Ang     1260E3  {Cambambe Extension}
NMz     1322E3 {Cahorra Bassa Extension}
Zam     743E3 {Kariba North Extension, only if Batoka}
Zim     667E3 {Kariba South Extension, only if Batoka}
;
```

```
(hydro file, section 7)
Table   crfih(z,ih)  {Existing hydro capital recovery factor}
     Stat1  Stat2  Stat3  Stat4  Stat5
Ang  0.12   0.12   0.12
Mwi  0.12
NMz  0.12   0.12
Nam  0.12
SSA  0.12   0.12
Swz  0.12
DRC  0.12   0.12   0.12   0.12   0.12
Taz  0.12   0.12
```

```
Zam  0.12   0.12   0.12
Zim  0.12
```

Existing Transmission Lines

```
(lines file, section 1)
Table PFOVc(z,zp) {cost per MW of expanding existing lines in mill $}
     Bot  Les  Mwi   Nmz   Smz  Nam  NSA  SSA  Swz  Taz  DRC  Zam  Zim
Bot  0    0    0     0     0    0    .12  0    0    0    0    0    .150
Les  0    0    0     0     0    0    .15  0    0    0    0    0    0
Mwi  0    0    0     0.075 0    0    0    0    0    0    0    0    0
Nmz  0    0    0.075 0     0    0    1.5  0    0    0    0    0    .225
Smz  0    0    0     0     0    0    .27  0    .135 0    0    0    0
Nam  0    0    0     0     0    0    0    .36  0    0    0    0    0
NSA  .12  .15  0     1.5   .27  0    0    .80  .135 0    0    0    0
SSA  0    0    0     0     0    .36  .80  0    0    0    0    0    0
Swz  0    0    0     0     .135 0    .135 0    0    0    0    0    0
Taz  0    0    0     0     0    0    0    0    0    0    0    0.75 0
DRC  0    0    0     0     0    0    0    0    0    0    0    .055 0
Zam  0    0    0     0     0    0    0    0    0    0.75 .055 0    .05
Zim  .15  0    0     .225  0    0    0    0    0    0    0    .050 0
Parameter PFOVcost(z,zp) ; {convert to dollars}
   PFOVcost(z,zp) = 1e6*PFOVc(z,zp);
```

```
(lines file, section 2)
Table  crf(z,zp)  {capital recovery factor for transmission lines}
       Ang   Bot   Les   Mwi   Nmz   Smz   Nam   NSA   SSA
Ang    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Bot    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Les    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Mwi    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
NMz    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
SMz    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Nam    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
NSA    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
SSA    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Swz    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Taz    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
DRC    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Zam    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12
Zim    0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12  0.12

+      Swz   Taz   DRC   Zam   Zim
Ang    0.12  0.12  0.12  0.12  0.12
Bot    0.12  0.12  0.12  0.12  0.12
Les    0.12  0.12  0.12  0.12  0.12
Mwi    0.12  0.12  0.12  0.12  0.12
NMz    0.12  0.12  0.12  0.12  0.12
SMz    0.12  0.12  0.12  0.12  0.12
Nam    0.12  0.12  0.12  0.12  0.12
NSA    0.12  0.12  0.12  0.12  0.12
SSA    0.12  0.12  0.12  0.12  0.12
Swz    0.12  0.12  0.12  0.12  0.12
Taz    0.12  0.12  0.12  0.12  0.12
DRC    0.12  0.12  0.12  0.12  0.12
Zam    0.12  0.12  0.12  0.12  0.12
```

```
Zim   0.12  0.12  0.12  0.12  0.12
;
```

Existing Thermal plants

```
(thermal file, section 2)
Table Oexpcost(z,i)     expansion costs dollar per MW of old plants
      Stat1    Stat2    Stat3    Stat4    Stat5    Stat6
Ang   1000000
Bot   1000000
Les   1000000
Mwi   1000000
NMz   1000000
SMz   1000000
Nam   1000000  1000000
NSA   1000000  1000000  1000000  1000000  1000000  1000000
SSA   1000000
Swz   1000000
Taz   1000000
DRC   1000000
Zam   1000000
Zim   1000000  1000000  1000000  1000000

+       Stat7    Stat8    Stat9    Stat10
NSA     1000000  1000000  1000000  1000000
;

(thermal file, section 16)
Table   crfi(z,i) {capital recovery factor for old thermals}
      Stat1 Stat2 Stat3 Stat4 Stat5 Stat6
Ang   0.15
Bot   0.15
Les   0.15
Mwi   0.15
Nmz   0.15
Smz   0.15
Nam   0.15  0.15
NSA   0.15  0.15  0.15  0.15  0.15  0.15
SSA   0.15
Swz   0.15
Taz   0.15
DRC   0.15
Zam   0.15
Zim   0.15  0.15  0.15  0.15

+    Stat7  Stat8  Stat9  Stat10
NSA  0.15   0.15   0.15   0.15
```

Proposed New Hydro plants

```
(hydro file, section 1)
Table HNFcost(z,nh) Fixed Capital Cost (US$)
    newh1                      newh2               newh3               newh4
Ang 200E6 {Capanda}            150E6 {Cambabme}    0                   0
Les 19.3E6 {estmate ZYU }      0                   0                   0
Mwi 12E6  {Kapichiri 1 & 2}    57.5E6              167E6               165E6
{Lower fufu}
```

```
Nmz 260E6 {Mepandua Uncua}     0                   0                    0
Nam 408E6  {Epupua/Kunene}     0                   0                    0
Taz 90E6  {Kihansi lower}      146.3E6             128.75E6 {Mpanga}    0
DRC 9780e6 {Grand Inga I & 2}  6330e6              6120e6
6070e6
Zam 37E6   {itezhi-teshi}      112.5E6 {Kafue}     224.5E6 {Batoka N}   0
Zim 224.5E6  {Batoka S}        240E6 {Gokwe N}     0                    0
```

```
(hydro file, section 2)
Table HNVcost(z,nh) {Capital cost of additional Capacity $/MW new hydros}
    newh1                      newh2     newh3    newh4
Ang 534E3  {Capanda Extension}
Les 880E3  {Muela}
Mwi 375E3  {Shire River AD2003}  1322e3    1063e3   471e3
Nmz 650e3
Taz 1500e3                     1977e3    1438e3
DRC 217e3                      217e3     217e3    217e3
Zam 927e3                      750e3     122e3
Zim 1122e3                     800e3

* 880E3 $/Mw is an estimate
* assumed Shire is an extension to Kapichire
```

```
(hydro file, section 6)
Table crfnh(z,nh)       {capital recovery factor for new hydro}
     newh1  newh2  newh3  newh4
Ang  0.12   0.12   0.12   0.12
Bot  0.12   0.12   0.12   0.12
Les  0.12   0.12   0.12   0.12
Mwi  0.12   0.12   0.12   0.12
NMz  0.12   0.12   0.12   0.12
SMz  0.12   0.12   0.12   0.12
Nam  0.12   0.12   0.12   0.12
NSA  0.12   0.12   0.12   0.12
SSA  0.12   0.12   0.12   0.12
Swz  0.12   0.12   0.12   0.12
Taz  0.12   0.12   0.12   0.12
DRC  0.12   0.12   0.12   0.12
Zam  0.12   0.12   0.12   0.12
Zim  0.12   0.12   0.12   0.12
```

Proposed New Transmission Lines

```
(lines file, section 4)
Table   PFNFc(z,zp) New Tie lines Fixed cost mill US $
{SUFG Estimates: Assuming Inga to Capanda is 333 miles & Capapanda}
{to Kokerboom is 1200 miles}
{@ 1.1 million dollars per mile}
                        {converted below table  to $}
    Ang   Bot Mwi   Les Nmz   Smz   Nam  NSA    SSA Swz    Taz DRC  Zam   Zim
Ang 0     0   0     0   0     0     1320 0      0   0      0   367  0     0
Bot 0     0   0     0   0     0     0    0      0   0      0   0    0     0
Les 0     0   0     0   0     0     0    0      0   0      0   0    0     0
Mwi 0     0   0     0   40.02 0     0    0      0   0      0   0    100   0
Nmz 0     0   40.02 0   0     783   0    0      0   0      0   0    0     0
```

```
Smz 0    0   0     0   783   0     0    0      0   0     0   0    0     0
Nam 1320 0   0     0   0     0     0    0      0   0     0   0    0     0
NSA 0    0   0     0   0     0     0    0      0   0     0   0    0     0
SSA 0    0   0     0   0     0     0    0      0   0     0   0    0     0
Swz 0    0   0     0   0     0     0    0      0   0     0   0    0     0
Taz 0    0   0     0   0     0     0    0      0   0     0   0    0     0
DRC 367  0   0     0   0     0     0    0      0   0     0   0    414   0
Zam 0    0   100   0   0     0     0    0      0   0     0   414  0     0
Zim 0    0   0     0   0     0     0    0      0   0     0   0    0     0
Parameter PFNFcost(z,zp); {convert from millions to  dollars}
   PFNFcost(z,zp) = PFNFc(z,zp)*1E6;

(lines files, section 5)
Table PFNVc(z,zp) {Cost of additional capacity on new lines Mill $/MW}
* converted to $/MW below
    Ang  Bot  Mwi  Les  Nmz  Smz  Nam  NSA SSA  Swz Taz  DRC  Zam  Zim
Ang 0    0    0    0    0    0    .605 0   0    0   0    .165 0    0
Bot 0    0    0    0    0    0    0    0   0    0   0    0    0    0
Les 0    0    0    0    0    0    0    0   0    0   0    0    0    0
Mwi 0    0    0    0    0    0    0    0   0    0   0    0    .50  0
Nmz 0    0    0    0    0    0    0    0   0    0   0    0    0    0
Smz 0    0    0    0    0    0    0    0   0    0   0    0    0    0
Nam .605 0    0    0    0    0    0    0   .165 0   0    0    0    0
NSA 0    0    0    0    0    0    0    0   0    0   0    0    0    0
SSA 0    0    0    0    0    0    .165 0   0    0   0    0    0    0
Swz 0    0    0    0    0    0    0    0   0    0   0    0    0    0
Taz 0    0    0    0    0    0    0    0   0    0   0    0    0    0
DRC .165 0    0    0    0    0    0    0   0    0   0    0    .414 0
Zam 0    0    .50  0    0    0    0    0   0    0   0    .414 0    0
Zim 0    0    0    0    0    0    0    0   0    0   0    0    0    0
```

Proposed New Thermal plants

```
(thermal file, section 3)
Table   NTexpcost(z,ni)  {expansion costs dollar/MW of new gas turbine
plants}
     NS1     NS2     NS3
Ang  300000  300000  300000
Bot  300000  300000  300000
Les  300000  300000  300000
SMz  300000  300000  300000
Nam  300000  300000  300000
NSA  324000  300000  300000
SSA  300000  300000  300000
Taz  600000  900000  300000
Zim  300000  300000  300000
;

(thermal file, section 1)
Table FGCC(z,ni)  {fixed costs for new combined-cycle plants}
     NS1    NS2    NS3
Ang  109E6  109E6  109E6
Bot  109E6  109E6  109E6
Les  109E6  109E6  109E6
Mwi  109E6  109E6  109E6
NMz  109E6  109E6  109E6
```

```
SMz  109E6  109E6  109E6
Nam  650E6  109E6  109E6
NSA  109E6  109E6  109E6
SSA  109E6  109E6  109E6
Swz  109E6  109E6  109E6
Taz  109E6  109E6  109E6
DRC  109E6  109E6  109E6
Zam  109E6  109E6  109E6
Zim  109E6  109E6  109E6
;
```

```
(thermal file, section 3)
Table   NCCexpcost(z,ni)  {expansion costs dollar/MW of new combined cycle
plants}
     NS1     NS2     NS3
Ang  412000  412000  412000
Bot  412000  412000  412000
Les  412000  412000  412000
SMz  412000  412000  412000
Nam  412000  412000  412000
NSA  412000  412000  412000
SSA  412000  412000  412000
Taz  412000  412000  412000
Zim  412000  412000  412000
;
```

```
(thermal file, section 4)
Table   NSCexpcost(z,ni) {expansion costs dollar/MW of new small coal plants}
     NS1      NS2      NS3      NS4      NS5
Ang  1433333  1433333
Bot  1750e3   1750e3
Les  1433333  1433333
SMz  1260e3   1433333
Nam  866e3    866e3
NSA  277e3    109e3    542e3    108e3    844e3
SSA  1433333  1433333
Taz  1433333  1433333
Zim  1547e3   923e3
;
```

```
(thermal file, section 2)
Table FGLC(z,ni)  {fixed costs for new large coal plants}
     NS1   NS2   NS3   NS4   NS5   NS6   NS7   NS8
Ang  581E6 581E6
Bot  581E6 581E6
Les  581E6 581E6
Mwi  581E6 581E6
NMz  581E6 581E6
SMz  581E6 581E6
Nam  581E6 581E6
NSA  812E6 812E6 812E6 812E6 812E6 812E6 812E6 812E6
SSA  844E6 812E6 812E6 812E6
Swz  581E6 581E6
Taz  581E6 581E6
DRC  581E6 581E6
```

```
Zam  581E6 581E6
Zim  581E6 581E6
 ;

(thermal file, section 4)
Table   NLCexpcost(z,ni) {expansion costs dollar/MW of new large coal plants}
     NS1    NS2    NS3    NS4    NS5    NS6    NS7    NS8
Ang  866000 866000
Bot  866000 866000
Les  866000 866000
SMz  866000 866000
Nam  866000 866000
NSA  857000 857000 857e3  857e3  857e3  857e3  857e3  857e3
SSA  866000 866000 866e3  866e3
Taz  866000 866000
Zim  866000 866000
;

(thermal file, section 17)
Table       crfni(z,ni)       {capital recovery factor for new thermal}
     NS1   NS2   NS3   NS4   NS5   NS6   NS7   NS8
Ang  0.15  0.15  0.15
Bot  0.15  0.15  0.15
Les  0.15  0.15  0.15
Mwi  0.15  0.15  0.15
NMz  0.15  0.15  0.15
SMz  0.15  0.15  0.15
Nam  0.15  0.15  0.15
NSA  0.15  0.15  0.15  0.15  0.15  0.15  0.15  0.15
SSA  0.15  0.15  0.15  0.15
Swz  0.15  0.15  0.15
Taz  0.15  0.15  0.15
DRC  0.15  0.15  0.15
Zam  0.15  0.15  0.15
Zim  0.15  0.15  0.15

(thermal file, section 3)
Table   NCCexpcost(z,ni)  {expansion costs dollar/MW of new combined cycle
plants}
     NS1     NS2     NS3
Ang  412000  412000  412000
Bot  412000  412000  412000
Les  412000  412000  412000
SMz  412000  412000  412000
Nam  412000  412000  412000
NSA  412000  412000  412000
SSA  412000  412000  412000
Taz  412000  412000  412000
Zim  412000  412000  412000
;

(thermal file, section 4)
Table   NLCexpcost(z,ni) {expansion costs dollar/MW of new large coal plants}
     NS1    NS2    NS3    NS4    NS5    NS6    NS7    NS8
Ang  866000 866000
Bot  866000 866000
Les  866000 866000
```

```
SMz  866000 866000
Nam  866000 866000
NSA  857000 857000 857e3  857e3  857e3  857e3  857e3  857e3
SSA  866000 866000 866e3  866e3
Taz  866000 866000
Zim  866000 866000
;
```

Objective Function Multipliers

```
(gms file, section 1)
parameter Mperiod(ty)  multiplier of year;
Mperiod(ty) = n;


(gms file, section 9)
Parameter Mseason(ts) /
      summer 1.5 {2* 9/12}
      winter 0.5 {2* 3/12}
      /;

(gms file, section 2)
Parameter Mday(td) multiplier of days in a season
      /offpeak 26
      peak     26
      average 130/

(demand file, section 2)
Parameter Mtod(th) / number of hours in each type per day
      hr9     1
      avnt    8
      hr19    1
      hr20    1
      hr21    1
      avdy    12 / ;
```