General Training Manual for the Long-Term Planning Model

Research Report
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Equity and Growth through Economic Research

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Introduction

Purdue University's State Utility Forecasting Group (SUFG) advises and is supported by the Indiana State Government since 1980. SUFG's forecasting and marketing models provide quantitative analysis of many electricity policy scenarios. All of the interested stakeholders have full and equal access to the SUFG model formulation and so there is a transparency to the analysis that promotes in-depth study of options for construction of new capacity (generation and transmission), deregulation, and tariff structures that face government and the utilities.

The SUFG forecasting and long-term planning models use mathematical programming and operations research techniques (linear and mixed integer) to combine the many economic and technical objectives and constraints into clearly defined algorithms for optimal (cost minimization) solutions.

The SUFG electricity and natural gas systems planning models have been employed internationally since 1995. Many countries around the world have yet to develop the capacity for construction and use of these analytical tools and so Purdue's SUFG is being instrumental in promoting programs of collaboration with governments, utilities, and universities in other countries. These collaborative international modeling activities encourage regional cooperation and provide a substantial quantitative basis on which to build improved regional electricity trading policies with potential enormous cost saving options from collective construction and closer regional integration.

Purdue's first major electricity trade modeling project, outside of the USA, was with the Southern African Power Pool (SAPP). This work was funded by the USAID with much interest and general support from the DOE and the World Bank. Following the successful work with SAPP other international projects are developing. The organization of these international projects is administered through Purdue University's Power Pool Development Group (PPDG). Both the SUFG and PPDG are housed at Purdue University's Institute for Interdisciplinary Engineering Studies (IIES).

There is a fully detailed description of the SUFG long-term electricity-planning model in the "Long-Term Model User Manual," Edition 5, June 2000. This can be freely downloaded from the web page:

http://iies.www.ecn.purdue.edu/IIES/SUFG/

The User Manual provides a full description of the objective function, load balance equation, capacity and reliability constraints, and technical operating instructions. The user-friendly interface is also described. It is written with the technical user and operations research specialist in mind.

This current document, the General Training Manual, is for the general electricity policy decision maker. It is for the person who is not so involved or interested in the precise line by line description of the program structure and who does not have the time to investigate it and to look into all the technical details of the model. This current manual is written to provide understanding and background to the modeling and for training in power pool data collection.

This manual consists of seven sections:

- Section 1 - Definitions of Economic Terms
- Section 2 - Costing and Computing Concepts
- Section 3 - Basic Electricity Modeling Formulation
- Section 4 - The Generic Seven Country Regional Model
- Section 5 - Inputs and Outputs to the Model
- Section 6 - Template Data Collection Sheets
- Section 7 - Modeling Notation

Section 1
Definition of Economic Terms

As we start to look at energy modeling, let's first be sure of some of our essential economic terms. Let's first look at some definitions.

1.1 Economic Cost versus Accounting Cost:

"An economist thinks of cost differently from an accountant, who is concerned with the firm's financial statements. Accountants tend to take a retrospective look at a firm's finances because they have to keep track of assets and liabilities and evaluate past performance.

Economists take a forward-looking view. They are concerned with what cost is expected to be in the future, and how the firm might be able to rearrange its resources to lower its cost and improve its profitability. They must therefore be concerned with opportunity cost, the cost associated with opportunities that are foregone by not putting the firm's resources to their highest value use." [1]

1.2 Opportunity Cost:

The benefit foregone by using a scarce resource for one purpose instead of for its next best alternative use.

An *opportunity cost* is incurred because of the use of limited resources, such that the opportunity to use those resources to monetary advantage in an alternative use is foregone. Thus, it is the cost of the best rejected (i.e., foregone) opportunity and is often hidden or implied.

Example:
Suppose that a construction project involves the use of a storage space presently owned by a company. The cost for that space to the project should be the income or savings that possible alternative uses of the space may bring to the company. In other words, the opportunity cost for the space should be the income derived from the best alternative use of it. This may be more than or less than the average cost of that space obtained from the accounting records of the company [3].

1.3 Fixed & Variable Costs:

Fixed costs are those unaffected by changes in activity level over a feasible range of operations for the capacity or capability available. Typical fixed costs include interest costs on borrowed capital, insurance and taxes on facilities, general management and administrative salaries, and license fees. Of course, any cost is subject to change, but fixed costs tend to remain constant over a specific range of operating conditions. When large changes in usage of resources occur, or when plant expansion or shutdown is involved, fixed costs will be affected.

Variable costs are those associated with an operation that vary in total with the quantity of output or other measures of activity level. If you were making an engineering economic analysis of a proposed change to an existing operation, the variable costs would be the primary part of the prospective differences between the present and changed operations as long as the range of activities is not significantly changed. For example, the costs of material and labor used in a product or service are variable costs – because they vary in total with the number of output units – even though the costs per unit stay the same.

1.4 Marginal Cost:

An *incremental or marginal cost* is the additional cost, or revenue, that results from increasing the output of a system by one (or more) units. Marginal cost is often associated with "go/no go" decisions that involve a limited change in output or activity level. For instance, the incremental cost per mile for driving an automobile may be $0.27, but this cost depends on considerations such as total mileage driven during the year (normal operating range), mileage expected for the next major trip, and the age of the automobile. Also, it is common to read of the "incremental cost of producing a barrel of oil." The incremental cost (or revenue) is often quite difficult to determine in practice.

With electricity generation the marginal cost is a function of how much advance notice is given for demand. One additional MW in a minutes time horizon is a very different cost to an additional MW in one months time.

The data in Table 4.1 describe a company with a fixed cost of $50. Variable cost increases with output, as does total cost. The total cost is the sum of the fixed cost in column (1) and the variable cost in column (2). The marginal cost of increasing from output from 2 to 3 units is $20, because the variable cost of the firm increases from $78 to $98. Total cost of production also increases from $128 to $148. The average total cost of producing at a rate of five units is $36, $180/5. Average cost tells us the per unit cost of production.

Table 4.1 Short-Run Costs

Rate of Output	Fixed Cost (FC) (1)	Variable Cost (VC) (2)	Total Cost (TC) (3)	Marginal Cost (MC) (4)	Average Fixed Cost (AFC) (5)	Average Variable Cost (AVC) (6)	Average Total Cost (ATC) (7)
0	50	0	50	-	-	-	-
1	50	50	200	50	50	50	100
2	50	78	128	28	25	39	64
3	50	98	148	20	16.7	32.7	49.3
4	50	112	162	14	12.5	28	40.5
5	50	130	180	18	10	26	36
6	50	150	200	20	8.3	25	33.3
7	50	175	225	25	7.1	25	32.1
8	50	204	254	29	6.3	25.5	31.8
9	50	242	292	38	5.6	26.9	32.4
10	50	300	350	58	5	30	35
11	50	385	435	85	4.5	35	39.5

Example:

A team of four colleagues live in the same geographical area and intend to travel together to a conference (a distance of 400 miles each way). One of the team has a car and agrees to take the other three if they will pay the cost of operating the car for the trip. When they return from the trip, the owner presents each of them with a bill for $102.40, stating that he has kept careful records of the cost of operating the car and that, based on an annual average of 15,000 miles, their cost per mile is $0.384. The three others felt that the charge is too high and ask to see the cost figures on which it is based. The owner shows them the following list:

Cost Element	Cost per Mile
Gasoline	$0.120
Oil and lubrication	0.021
Tires	0.027
Depreciation	0.150
Insurance and taxes	0.024
Repairs	0.030
Garage	0.012
Total	$0.384

The three riders, after reflecting on the situation, form the opinion that only the costs for gasoline, oil and lubrication, tires, and repairs are a function of mileage driven (variable costs) and thus could be caused by the trip. Because these four costs total only $0.198 per mile, and thus $158.40 for the 800-mile trip, the share for each person would be $158.40/3 = $52.80. Obviously, the opposing views are substantially different. Which, if either, is correct? What are the consequences of the two different viewpoints in this matter, and what should the decision-making criterion be?

Solution:
In this instance assume that the owner of the automobile agreed to accept $52.80 per person for the three riders, based on the variable costs that were purely incremental for the conference trip versus the owner's average annual mileage. That is, the $52.80 per person is the "with a trip" cost relative to the "without" alternative.

Now, what would the situation be if the team, because of the low cost, returned and proposed another 800-mile trip the following weekend? And what if there were several more such trips on subsequent weekends? Quite clearly, what started out to be a small marginal (and temporary) change in operating conditions – from 15,000 miles per year to 15,800 miles – soon would become a normal operating condition of 18,000 or 20,000 miles per year. On this basis, it would not be valid to compute the extra cost per mile as $0.198.

Because the normal operating range would change, the fixed costs would have to be considered. A more valid incremental cost would be obtained by computing the total annual cost if the car were driven, say, 18,000 miles, then subtracting the total cost for 15,000 miles of operation, and thereby determining the cost of the 3,000 additional miles of operation. From this difference the cost per mile for the additional mileage could be obtained. In this instance, the total cost for 15,000 miles of driving per year was 15,000 x $0.384 = $5,760. If the cost of service – due to increased depreciation, repairs, and so forth – turned out to be $6,570 for 18,000 miles per year, evidently the cost of the additional 3,000 miles would be $810. Then the corresponding incremental cost per mile due to the increase in the operating range would be $0.27. Therefore, if several weekend trips were expected to become normal operation, the owner would be on more reasonable economic ground to quote an incremental cost of $0.27 per mile for even the first trip. [3]

1.5 Sunk Cost:

A cost incurred in the past that cannot be retrieved as a residual value from an earlier investment. It is not an opportunity cost. In economics the sunk cost is equivalent to fixed cost in short-term decision making.

A classic example of sunk cost involves the replacement of assets. Suppose that your firm is considering the replacement of a piece of equipment. It originally cost $50,000, is presently shown on the company records with a value of $20,000, and can be sold for an estimated $5,000. For purposes of replacement analysis, the $50,000 is a sunk cost. However, one view is that the sunk cost should be considered as the difference between the value shown in the company records and the present realizable selling price. According to this viewpoint, the sunk cost is $20,000 minus $5,000, or $15,000. Neither the $50,000 or the $15,000, however, should be considered in an engineering economic analysis – except for the manner in which the $15,000 may affect income taxes.

1.6 Market Price:

The market price is the price at which a good or service is actually exchanged for another good or service (as an in kind payment) or for money (in which case it is a financial price) [2].

Example:

The market clearing price of electricity in a power pool is the price at which the most expensive unit is dispatched to meet demand. The results from the Purdue power pool model gives a pattern of expansions that occur if a tight power pool were to operate a power exchange, where every hour, a market clearing price was set.

1.7 Shadow Price:

Shadow price technically implies a price that has been derived from a complex mathematical model (for example, from linear programming). See the discussion that follows in Section 2.4.

1.8 Capital Recovery Factor (crf):

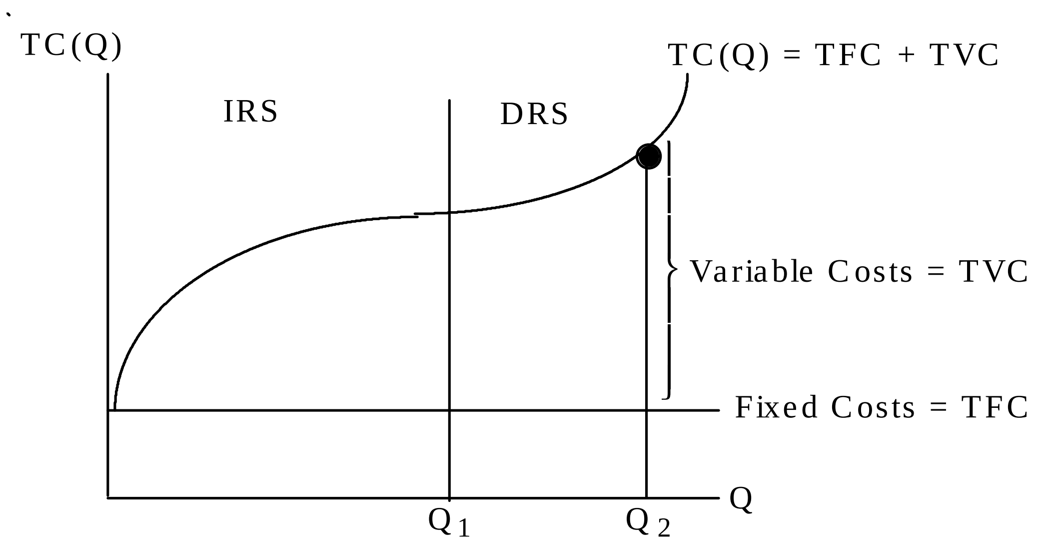
The annual payment that will repay a loan of 1 currency unit in "n" years with compound interest on unpaid balance – permits calculating equal installments necessary to repay (amortize) a loan over a given period at a stated interest rate "i". Such that: $crf = i(1+i)^n/[(1+i)^n-1]$

Section 2
Costing & Computing Concepts

Further to the general definitions, let us now consider more carefully some of these concepts.

2.1 Average ("unit") costs are usually misleading guides to choosing between alternatives; what's important are marginal, or incremental, costs.

Total Costs = TC(Q)



IRS = increasing returns to scale; DRS = decreasing returns to scale.

<u>Questions</u>: Why IRS? Why DRS? Why important?

- Average total cost = ATC = $\dfrac{TC(Q)}{Q} = \dfrac{TFC}{Q} + \dfrac{TVC}{Q} = AFC + AVC$

- Marginal, or incremental, cost = MC = $\dfrac{dTC(Q)}{dQ} = \dfrac{dTVC(Q)}{dQ}$

2.2 Marginal costs are what are critical in decision making, not average costs.

Example: Suppose that a company wishes to select the level of output, $\hat{Q}$, which maximizes profits.

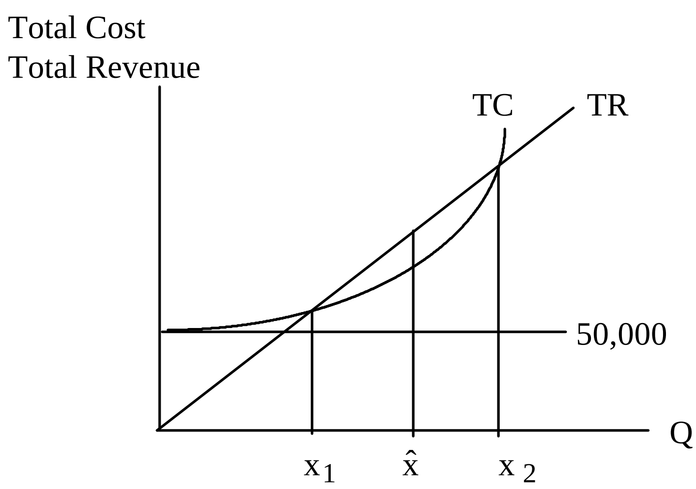
$$\text{Total profit} = \text{TR} - \text{TC};\ \max_{Q}\ \bar{P}Q - TC(Q) \Rightarrow \hat{Q}\ \text{ such that }\ \bar{P} = \frac{dTC(Q)}{dQ},\ \text{or}$$

$\hat{Q}$ such that Price = incremental cost.

Note the irrelevance of average *anything*, except, after the fact, to indicate profit/unit, cost/unit, price/unit.

Example:

Price = \$35/unit, Cost = $50{,}000 + 20.2x + 0.0001x^2$



What x maximizes profit? max $\rightarrow 35 - 20.2 - 0.0002x = 0$

$$\rightarrow\ = \frac{14.8}{0.0002} = 74{,}000$$

Questions: What are x_1 and x_2?

Is the \$50,000 relevant? What if the \$50,000 could be avoided?

Question: When can average costs be used in decision-making?

- When AC = MC, i.e., FC = 0, VC linear.

A common average cost is *depreciation*. Equipment lasts 10 years, costs \$10,000; want to cost it on a yearly basis. Use straight-line depreciation of \$1,000/year. While depreciation is important for tax purposes, it is irrelevant for decision making, except as it affects after-tax profits.

Example:

Trying to decide which plant should produce a new product.

(a) New Plant: Low out-of-pocket, high depreciation expenses

Annual variable cost	$\$1 \times 10^6$	
Annual depreciation	$\underline{\$2 \times 10^6}$	
		$\$3 \times 10^6$

(b) Old Plant: High out-of-pocket, low depreciation expenses

Annual variable cost	$\$1.5 \times 10^6$	
Annual depreciation	$\underline{\$1 \quad \times 10^6}$	
		$\$2.5 \times 10^6$

Choose (b)? No! Choose (a); minimize out-of-pocket costs.

Determining marginal costs frequently a tricky business:

-- Long-term contracts (labor, fuel)
-- Costs of change (hire/fire)
-- Capacity utilization, when capacity additions are "lumpy"

2.3 The irrelevance of sunk cost.

Sunk Costs: A cost irretrievably incurred in the past that cannot be altered by any action taken from now on.

Examples:

- Binding contractual agreement to purchase a specialized piece of equipment with no salvage value.
- I purchased IBM stock @ \$130/share; it is now \$80/share. Should the fact that I purchased @ \$130 enter into the decision to keep or sell the stock?

Question: What is the relation between fixed and sunk costs?

Fixed Costs: Once incurred, remain invariant for all alternative courses of action under consideration.

Examples:

- Cost of a factory of fixed size prior to decision to construct

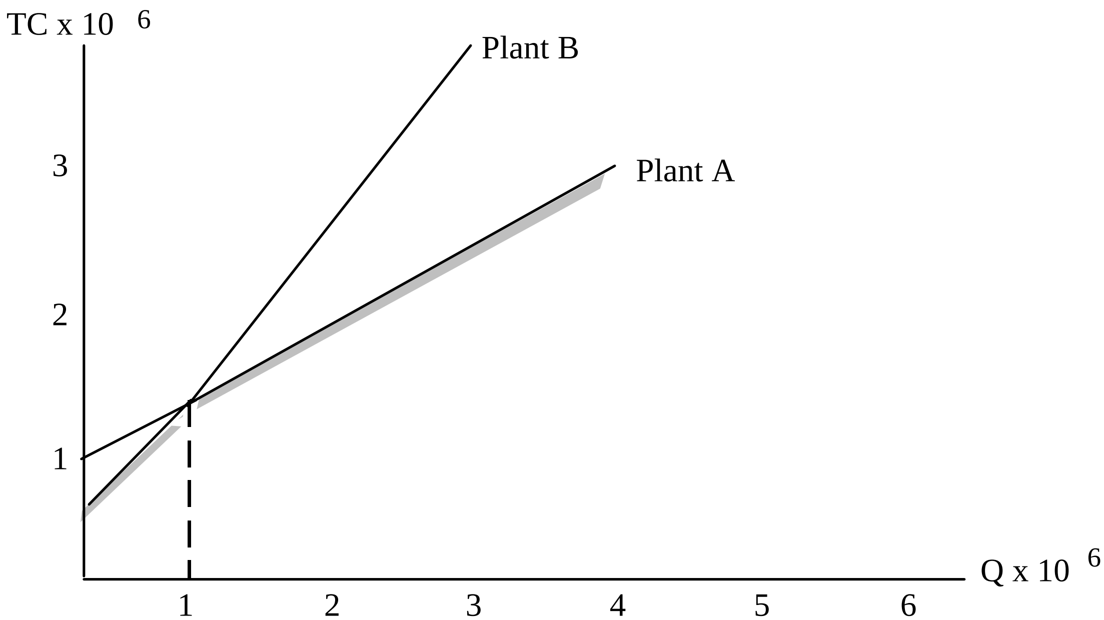
- Salaries, cost of machinery, etc., which do not vary as production varies

Suppose I'm trying to figure out what type of assembly line to build: (A) an expensive, highly automated one, or (B) a cheaper, less automated one.

A	B
Equipment: 1×10^6	Equipment 0.5×10^6
Marginal operating cost/unit: 50¢	Marginal operating cost/unit: \$1.00
$TC(Q) = 1 \times 10^6 + 0.50Q$	$TC = 0.5 \times 10^6 + 1.00Q$

Now: Before I choose: both equipment costs and operating costs are variable.

Which to choose depends on expected sales; $< 1 \times 10^6$, choose B, $> 1 \times 10^6$, choose A.



After I choose and construct, *fixed* costs become *sunk* costs to the extent that I cannot recover equipment investment, and they become *irrelevant* for decision-making.

Question: Do all sunk costs arise from fixed costs?
Answer: No. Even fuel costs can be sunk costs, if a take or pay contract is signed.

2.4 LaGrange Multipliers

Demand theory is based on the premise that consumers maximize utility subject to a budget constraint. Utility (U, the level of satisfaction that a person gets from consuming a good or undertaking an activity) is assumed to be an increasing function of the quantities of goods consumed, but marginal utility is assumed to decrease with consumption. The consumer's optimization problem when there are two goods, X and Y, may then be written as

$$\text{Maximize } U(X,Y) \qquad (1)$$

subject to the constraint that all income is spent on the two goods:

$$P_X X + P_Y Y = I \qquad (2)$$

Here, U( ) is the utility function, X and Y are the quantities of the two goods that the consumer purchases, P_X and P_Y are the prices of the goods, and I is income. (To simplify the mathematics, we assume that the utility function is continuous (with continuous derivatives) and that goods are infinitely divisible.) [3]

To determine the individual consumer's demand for the two goods, we choose those values of X and Y that maximize Equation (1) subject to Equation (2). When we know the particular form of the utility function, we can solve to find the consumer's demand for X and Y directly. however, even if we write the utility function in its general form U(X,Y), the technique of constrained optimization can be used to describe the conditions that must hold if the consumer is maximizing utility.

To solve the constrained optimization problem given by Equations (1) and (2), we use the method of Lagrange multipliers, which works as follows. We first write the "Lagrangian" for the problem. To do this, rewrite the constraint in Equation (2) as: $P_X X + P_Y Y - I = 0$. The Lagrangian (L) is then:

$$L = U(X,Y) - \lambda(P_X X + P_Y Y - I) \qquad (3)$$

The parameter λ is called the *Lagrange multiplier.*

If we choose values of X and Y that satisfy the budget constraint, then the second term in Equation (3) will be zero, and maximizing Φ will be equivalent to maximizing U(X,Y). By differentiating Φ with respect to X, Y, and λ and then equating the derivatives to zero, we obtain the necessary conditions for a maximum (these conditions are necessary for an "interior" solution in which the consumer consumes positive amounts of both goods; however, the solution could be a "corner" solution in which all of one good and none of the others are consumed):

$$\begin{aligned} &MU_X(X,Y) - \lambda P_X = 0 \\ &MU_Y(X,Y) - \lambda P_Y = 0 \\ &P_X X + P_Y Y - I = 0 \end{aligned} \qquad (4)$$

Here, MU is short for marginal utility (i.e., $MU_X(X,Y) = \partial U(X,Y)/\partial X$, the change in utility from a small increase in the consumption of good X).

The third condition is the original budget constraint. The first two conditions of Equation (4) tell us that each good will be consumed up to the point at which the marginal utility from consumption is a multiple of (λ) of the price of the good. To see the implication of this, we combine the first two conditions to obtain the *equal marginal principle:*

$$\lambda = [MU_X(X,Y)/P_X] = [MU_Y(X,Y)/P_Y] \qquad (5)$$

Note also that $\hat{\lambda} = \partial L / \partial I$; it can be shown that $\hat{\lambda} = \partial \hat{U} / \partial I$; e.g., the change in the utility function with a change on the right-hand side of the constraint – thus, the term "shadow price" – it is what you gain by a relaxation of a constraint.

In other words, the marginal utility of each good divided by its price is the same. To be optimizing, *the consumer must be getting the same utility from the last dollar spent by consuming either X or Y.* Were this not the case, consuming more of one good and less of the other would increase utility.

To characterize the individual's optimum in more detail, we can write the information in Equation (5) to obtain:

$$MU_X(X,Y)/MU_Y(X,Y) = P_X/P_Y \qquad (6)$$

2.5 Operations Research (OR, Management Science, Decision Analysis)

Operations research is sometimes also called OR, Management Science, or decision analysis. In the process of taking major project decisions there will be thousands and probably millions of options available. Consider a few simple examples:

Consider the options available with the unit commitment problem for one coal fired generating unit during one time period. List the options of when it is switched on and off.

Example:

	On	**Off**	
Condition 1	**0**	**1**	Unit is switched off.
Condition 2	**1**	**0**	Unit is switched on.

Only two options are possible.

Example:
Consider the unit commitment problem and the options again but this time there are two generating stations, one thermal and one hydropower. The thermal station has two generating units and in the hydropower station there is one unit. How many options or combinations of switched-on units are available during one time period?

Option No:	1	2	3	4	5	6	7	8
Condition:	On/Off	On/Off	On/Off	On/Off	On/Off	On/Off	On/Off	On/Off
Unit 1	0/1	1/0	0/1	0/1	1/0	1/0	0/1	1/0
Unit 2	0/1	0/1	1/0	0/1	1/0	0/0	1/0	1/0
Unit 3	0/1	0/1	0/1	1/0	0/1	1/0	1/0	1/0

With this simple example, in one time period (say one hour), there are already 8 different options available.

With 2 conditions and 3 units there are:

$2^3 = 8$ possible operating options available.

Example:
Consider the example above again but this time let there be two time periods called hour 1 and hour 2.

In hour 1 there is option 1 and following in hour 2 there would be 8 options.
In hour 1 there is option 2 and following in hour 2 there would be 8 options.
In hour 1 there is option 3 and following in hour 2 there would be 8 options.
Etc. etc. . . . . .
In hour 1 there is option 8 and following in hour 2 there would be 8 options.

With a second time period being involved there are now 64 possible operating options to consider. The complexity of the problem increases exponentially.

There are now $2^3 \times 2^3 = 64$ conditions.
$2^6 = 64$

In one day with 24 one hour time periods the number of operating options available will be equal to:

$$2^{3 \times 24} = 2^{72}$$
$$2^{72} = 4.722366483 \times 10^{21}$$
$$2^{72} = 4{,}722{,}366{,}483{,}000{,}000{,}000{,}000$$
$$= 4{,}722 \text{ trillion trillion options}$$

Thus a relatively simple problem can quickly involve an unmanageable number of options.

Imagine the size or complexity of the decision process for the unit commitment in an electricity utility or power pool in which there are several or more power generating stations with scores of units to be switched on and off over hourly periods for days and weeks.

It can be appreciated that a computer solver for real problems in decision analysis will be indispensable as a manual procedure would be extremely long and prone to mistakes – effectively impossible to do. The GAMS and CPLEX solvers are used for this type of problem (using branch and bound techniques).

2.6 Introduction to GAMS (General Algebraic Modeling System)

The basic structure of GAMS has the following components:-

SETS (indices)
PARAMETERS, TABLES, SCALARS (data)
VARIABLES
EQUATIONS
MODEL & SOLVE statements

These can be best understood with an example. Consider the following:

(Adapted from “GAMS, A User’s Guide”, Anthony Brooke et al, 1988)
We are given the supplies at several markets for a single commodity (electricity) at a single point in time. We are given the unit costs of shipping the commodity from plants to markets. The economic question is how much shipment should there be between each plant and each market so as to minimize the total shipment cost?

		Markets		
	Harare	Lusaka	Pretoria	*Supplies (MWh)*
Plants		*Wheeling Distances (Thousands of miles)*		
Inga	1.6	1.3	2.2	2100
HCB	0.3	0.6	1.0	1600
Demands (MWh)	700	400	2500	

SETS - Indices

i = plants, j = markets

PARAMETERS, TABLES, SCALARS - Given Data

H_i = supply of commodity at plant i (MW)
D_j = demand for commodity at market j (MW)
C_{ij} = cost of MW shipping/wheeling to ship from plant i to market j (MW)

DECISION VARIABLES

X_{ij} = quantity of commodity to ship from plant i to market j (MW)
Where $X_{ij} \geq 0$ for all i,j

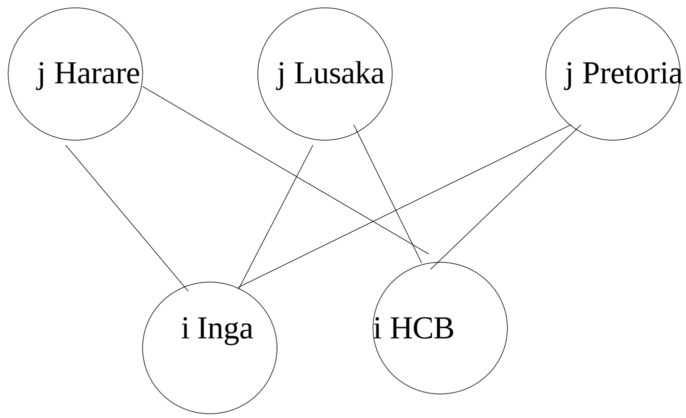
EQUATIONS – COST, SUPPLY & DEMAND must be declared.

MODEL Supply limit at plant i $\sum_j X_{ij} \leq H_i$

Satisfy demand at market j $\sum_i X_{ij} \geq D_j$

Objective Function

$$\text{Minimize} \quad \sum_i \sum_j C_{ij} X_{ij}$$



Shipping costs are approximately $2 per MWh per thousand miles.

GAMS FORMAT (*print-out of the gams code)*:

```
SET   I     Generation plants /     Inga, HCB   /;
SET   J     Demand Centers    /     Harare, Lusaka, Pretoria      /;

PARAMETER   H(I)  Exporting capacity (MWh) of plant I
      /           Inga 2100
                  HCB 1600    /;

PARAMETER   D(J)  Demand (MWh) at Market J
      /           Harare 700
                  Lusaka 400
                  Pretoria 2500     /;

TABLE L(I,J)      Distance in thousands of miles from I to J
            Harare            Lusaka            Pretoria
Inga        1.6         1.3         2.2
HCB         0.3         0.6         1.1   ;

SCALAR            W     Wheeling charge in $ per thousand miles   / 2 /;

PARAMETER C(I,J);
      C(I,J) = W*L(I,J);

VARIABLE          X(I,J)            Shipment quantities in MWh
VARIABLE          Z           Total shipment cost in thousands of $

POSITIVE VARIABLE X ;

EQUATION          COST              Define objective function
EQUATION          SUPPLY(I)         Observe supply limit at plant I
EQUATION          DEMAND(J)         Satisfy demand at market J    ;

                  COST..            Z =E= SUM((I,J),C(I,J)*X(I,J))      ;
                  SUPPLY(I)..       SUM(J,X(I,J)) =L= H(I)        ;
                  DEMAND(J)..       SUM(I,X(I,J)) =G= D(J)        ;

MODEL  ELEC /     ALL   /           ;
SOLVE   ELEC USING  LP  MINIMIZING  Z     ;
DISPLAY  X.L,  X.M
```

GAMS OUTPUT:

```
ITERATION COUNT, LIMIT         6        10000
Cplex 6.0, GAMS Link 12.0-7, 386/486 DOS
Optimal solution found.
```

Objective :   10480.000000

```
VAR X           Shipment quantities in MWh
                 LOWER      LEVEL     UPPER    MARGINAL
Inga.Harare        .          .        +INF      0.400
Inga.Lusaka        .       400.000     +INF        .
Inga.Pretoria      .      1600.000     +INF        .
HCB .Harare        .       700.000     +INF        .
HCB .Lusaka        .          .        +INF      0.800
HCB .Pretoria      .       900.000     +INF        .
```

The total shipment cost (minimized) for meeting the demand at the three markets amounts to \$10480. The optimal shipments are obtained by Inga sending out 400MWh to Lusaka and 1600MWh to Pretoria and by HCB sending out 700MWh to Harare and 900MWh to Pretoria.

2.7 Computing Requirements

The computing requirements to run the Purdue power pool models can be met with a new PC (Pentium 3 etc) or the latest laptop. The speed of the processor is important for an efficient use of the model and it is recommended that at least 500MHz is used. A large memory is also an important requirement. The Purdue Generic Seven Country Model is free. The regional models that have already been tested by Purdue have confidential data populating them and for this reason can not be distributed. Two commercial solvers are needed to run the model and these are GAMS and CPLEX. More details can be obtained from the LT Model User Manual. A total expenditure of about \$16000 will be adequate to fully install the system (hardware and software) for the commercial user. Educational institutions are eligible for substantial cost reductions with the solvers.

Section 3
Basic Electricity Modeling Formulation

3.1 MODEL I: Short Run, Power Trade Only

In the short-run model I the objective is to minimize the total costs that arise from the cost of operations (fuel and maintenance), distributed generation costs, and the cost of unserved MW.

$$\min \sum_t \sum_i \sum_z \overline{c(i,z)} PG(i,z,t) + \overline{DG\cos t} DG(z,t) + \overline{UMcost} UM(z)$$

i.e.: Minimizing over all hours, all stations, and all countries, the sum of fuel costs (cost/MW times MW) plus demands met by distributed generation plus unsatisfied reserve requirements.

$\overline{c(i,z)}$	= Fuel Cost/MW at i in z ($)
PG(i,z,t)	= Power Generation at i in z during t (MW)
$\overline{DGcost}$	= Cost/MW of distributed generation demand ($)
DG(z,t)	= Distributed Generation in z during t (MW)
$\overline{UMcost}$	= Cost/MW of unmet reserves ($)
UM(z)	= Unmet reserve requirement in z (MW)

This minimization is subject to the following constraints:

$$\sum_i PG(i,z,t) + \sum_{zp} PF(zp,z)\{1-Pfloss(zp,z)\} + DG(z,t) = D(z,t) + \sum_{zp} PF(z,zp)$$

PF(zp,z)	= Power Flow from zp to z (MW)
Pfloss(zp,z)	= line loss from zp to z (%)
D(z,t)	= Demand in z during t (MW)

All generation in country z plus all imports from other countries (adjusted for line loss) is equal to the demand in country z plus exports to all countries.

$$PG(i,z,t) \le \overline{PGinit(i,z)}$$

$\overline{PGinit(i,z)}$ = initial capacities (MW)

The generation at station i, in country z, at any time t, is always less than or equal to the initial generating capacity of that station i in country z.

$$PF(z,zp) \le \overline{PFinit(z,zp)}$$

$\overline{\text{PFinit(i,z)}}$ = initial capacities (MW)

The power flow from country z to country zp will always be less than or equal to the initial power flow capability along the transmission line connecting country z to country zp.

$$\sum_i \frac{\overline{\text{PGinit}(i,z)}}{1+\overline{\text{res}(i,z)}} + \text{UM}(z) \geq \overline{\text{D}(z,\text{peak})}$$

res(i,z) = reserve requirement for i in z (%)
D(z,peak) = peak demand in z (MW)

The sum of total capacity of all the plants in country z, derated for their reserve margins, plus the unmet MW in country z will always exceed or be equal to the peak demand in country z plus the sum of the generation reserve requirements for all stations i in country z.

$$\sum_i \overline{\text{PGinit}(i,z)} \geq \text{A}(z)\,\text{D}(z,\text{peak})$$

A(z) = Autonomy factor for z (%)

The sum total of initial generating capacities from stations i, in country z, will be greater than or equal to the peak demand in country z times the autonomy of country z.

3.2 MODEL II: Short-Run, Power and Reserves Traded

In the short-run models I and II the objective is to minimize the total costs that arise from the cost of operations (fuel and maintenance), distributed generation costs, and the cost of unserved MW.

$$\min \sum_t \sum_i \sum_z \overline{c(i,z)}\text{PG}(i,z,t) + \overline{\text{DG}\cos t}\text{DG}(z,t) + \overline{\text{UMcost}}\text{UM}(z)$$

This minimization is subject to the following constraints:

$$\sum_i \text{PG}(i,z,t) + \sum_{zp} \text{PF}(zp,z)\left\{\overline{1-\text{Pfloss}(zp,z)}\right\} + \text{DG}(z,t) + \sum_{zo} \text{PF}(zp,z)$$

For each hour t, and in each country z, the sum total of generation from all stations, i, plus the sum total of all power flow imports from countries zp into country z (allowing for the transmission loss between country z and country zp) plus the distributed generation will be equal to the demand at hour t in country z plus the sum of total exports from country z to all other countries zp.

$$\sum_i \left\{ \left[\overline{\text{PGinit(i, z)}} \right] \Big/ \left[1 + \text{res(i, z)} \right] \right\} + \sum_{zp} \left\{ \left[\text{Fmax(zp, z)} \right] \Big/ \left[\overline{1 + \text{res(i, z)}} \right] \right\} +$$

$$\text{DG(z)} > \overline{\text{D(z, peak)}} + \sum_{zp} \text{Fmax(z, zp)} \quad \textit{(More than or equal to)}$$

Where Fmax(zp,z) = reserves held by zp for z.

Total generating capacity in country z, derated by the appropriate reserve margins plus reserves in other countries held for country z, derated by import reserve requirements, plus unmet reserve requirements must be ≥ peak demand plus reserves held by country z for other countries.

As also in Model I :-

$\sum_i \text{PGinit(i,z)} > \overline{\text{A(z)}}\,\overline{\text{D(z,peak)}}$

$\text{PG(i,z,y)} < \overline{\text{PGinit(i, z)}}$

$\text{PF(z,zp)} < \overline{\text{PFinit(z, zp)}}$

3.3 MODEL III: Long-Run Model

In the long-run model the objective is to minimize the total cost of operations (fuel, maintenance), distributed energy (or unmet energy), unmet reserve, and the cost of capital (crf, capital recovery factor) for capacity expansion. There is a time horizon of "y" years and a discount rate in this model.

$$\min \sum_{y=1}^{Y} \frac{\sum_i \sum_z \sum_t c\left(\overline{i,z}\right) \text{PG}\left(i,z,t,y\right) + \overline{\text{UEcost}}\,\text{UE}\left(z,t,y\right) + \overline{\text{UMcost}}\,\text{UM}\left(z,y\right)}{\left(1+\overline{\text{disc}}\right)^{y}} +$$

$$\sum_{y=1}^{Y} \sum_{t=y}^{Y} \frac{\overline{\text{crf}}\;\overline{\text{expcost}\left(i,z\right)}\,\text{PGexp}\left(i,z,y\right)}{\left(1+\overline{\text{disc}}\right)^{t}}$$

UE (Unmet Energy) is replaced with DG (Distributed Generation)

Where:

New variables:	PGexp(i,z,y)	= MW added in y at i in z
New parameters:	expcost(i,z)	= cost/MW of expansion at i in z
	disc	= discount rate for present value purposes
	crf	= capital recovery factor

This minimization is subject to the following constraints:

The Model II load balance and PF equations with the "y" (yearly) variable added.

$PG(i,z,t,y) < PGinit(i,z) + \sum_{\tau} PGexp(i,z,\tau)$

The power generation at station i, in country z, at hour t, and in year y will be less than or equal to the initial generating capacity at station i in country z plus the sum of all new expansions at the station i for the years up to year y.

$$\sum_{i} \frac{\overline{PGinit(i,z)} + \sum_{t=1}^{y} PGexp(i,z,t)}{\overline{1+res(i,z)}} + \sum_{zp} Fmax(zp,z,y) + UM(z,y) \geq D(z,peak,y) + \sum_{zp} Fmax(z,zp,y)$$

Same as before, except total generating capacity now includes additions up to and including year y.

$$\sum_{i} PGinit(i,z) + \sum_{t=1}^{y} PGexp(i,z,\tau) > A(z)D(z,peak,y)$$

Same as before, except total generating capacity now includes additions up to y.

Implications of Model Structure on Data:

- The model is a cash flow model; cash outflows entered into the model in the year in which they take place.

- No need to collect data on sunk costs (costs of past investments, etc.), only incremental costs.

- Model assumes equipment purchases financed by borrowed money – hence equipment purchase cost shows up as an annualized cost, equal to the capital recovery factor times the Engineering, Procurement, and Construction (EPC) cost, in each year subsequent to the purchase date.

- Plant operating costs (fuel, variable O&M, water costs) should be average incremental costs for each plant, not marginal costs which might be lower due to say, take or pay fuel contracts. Ignore variable heat rates for existing thermal plants – assume heat rate at 100% load.

- Plant equipment costs should be EPC costs, <u>not</u> including financing costs.

- Fixed O&M ($/kW/yr) should be considered only for new plants; they are sunk costs for existing plants (unless plants mothballed).

- Reserve margins, autonomy factors, discount rate, crf, unserved energy and reserve costs are <u>policy</u> decisions; get them, if you can but don't spend a lot of time.

- Line losses should be <u>average incremental</u>, not marginal.

- Line capacities should be <u>maximum transfer capability</u>, not maximum capacity.

- Generation capacities should be <u>net effective (dependable) sent out</u> capacity, not nameplate capacity.

- Demands (D(z,t,y)) should be <u>sent out</u> demands, not received demands.

Section 4
The Generic Seven Country Regional Model

4.1 Generation, Transmission and Demand:

The generic seven-country model has been constructed for demonstration and training purposes.

Electricity demand patterns for each time period and for each country are primary data requirements for populating the regional models. The electricity demand "drives" the model and is further explained in Sections 5 and 6. Taken into account are the load variations on an hourly, daily, weekly, season, yearly, and national basis. The forecasting of annual growth rates in demand needs special attention during the data collection process.

Table 4.1 Existing and Proposed Generation Stations

Country	Station Name	Details of Station
Country1	PG(1A)	Existing thermal station, 1200MW
	PG(1B)	Existing thermal station, 1600MW (expansion is possible up to 2500MW, costing $0.5m/MW)
	NH(1C)	Proposed new hydro station of 900MW with fixed cost $600m for the first 300MW and then a variable cost of $0.9/MW
	NH(1D)	Proposed new hydro station of 600MW with a fixed cost of $850m
	GT(1E)	Proposed new gas turbine station capable of expansion up to 600MW with a variable cost of $0.3m/MW
Country2	PG(2A)	Existing thermal station, 550MW
Country3	PG(3A)	Existing thermal station, 260MW
	GT(3B)	Proposed new gas turbine stations capable of expansion up to 600MW with a variable cost of $0.31m/MW
Country4	PG(4A)	Existing thermal station , 500MW
	PG(4B)	Existing combined cycle station, 1200MW, with option of expansion up to 2600MW, with a variable cost of $0.6m/MW
	CC(4C)	Proposed new combined cycle station, 300MW, with fixed cost of $175m and then the option of expansion up to 2100MW with a variable cost of $0.55m/MW
	GT(4D)	Proposed new gas turbine station, 300MW, with a variable cost of $0.325m/MW
Country5	PG(5A)	Existing combined cycle plant, 2400MW
	CC(5B)	Proposed new combined cycle station, 350MW, with fixed cost $ 405m and then the option of expansion up to 2800MW with a variable cost of $0.63m/MW
Country6	H(6A)	Existing hydropower station, 600MW
	NH(6B)	Proposed new hydropower station, 150MW, with fixed cost of $220m and then the option of expansion up to 900MW with a variable cost of $1.1/MW
Country7	H(7A)	Existing hydropower station, 450MW
	NH(7B)	Proposed new hydropower station, 200MW, with fixed cost of $270m, with the option of expansion up to 600MW at a variable cost of $1.3m/MW

The existing and proposed new generation and transmission infrastructure within this seven country regional model is shown in Figures 4.1 and 4.2. Peak demand in Country1 is 3000MW (Figure 4.1) and this country has an existing thermal generating capacity of 2800MW (station 1A is 1200MW and station 1B is 1600MW). This country has a generation deficit of 200MW and has proposed plans to construct a new hydropower station of 900MW (1C), a new hydropower station of 600MW (1D), and a gas turbine station of 600MW (1E).

Country1 is interconnected with Country2 (Figure 4.2) and can therefore import electricity at peak times. The proposed new generation and transmission project capacities are shown in italics in Figures 4.1 and 4.2. Table 4.1 lists the names of the existing thermal generating stations as PG(1A) and PG(1B) and shows the potentially new hydropower plant called NH(1C). Similarly the existing and proposed international transmission lines from Country1 are shown in Table 4.2.

Table 4.2 Existing and Proposed International Transmission Lines

From Country To Country	Interconnector Name	Details of International Interconnector
1 to 2	OT(1-2)	Existing international transmission line with a total load carrying capability of 100MW – can be expanded up to 2000MW at a cost of $0.2m/MW
2 to 3	OT(2-3)	Existing international transmission line with a total load carrying capability of 100MW – can be expanded up to 2000MW at a cost of $0.25/MW
3 to 4	OT(3-4)	Existing international transmission line with a total load carrying capability of 150MW – can be expanded up to 2000MW at a cost of $0.15/MW
4 to 5	NT(4-5)	Proposed new international transmission line with an initial carrying capability of 350MW having a fixed cost of $100m. This line can be further expanded up to 2000MW with a variable expansion cost of $0.16m/MW.
5 to 6	NT(5-6)	Proposed new international transmission line with an initial carrying capability of 300MW having a fixed cost of $40m This line can be further expanded up to 750MW with a variable expansion cost of $0.22m/MW.
6 to 2	NT(6-2)	Proposed new international transmission line with an initial carrying capability of 150MW having a fixed cost of $88m This line can be further expanded up to 750MW with a variable expansion cost of $0.15m/MW.
6 to 7	NT(6-7)	Proposed new international transmission line with an initial carrying capability of 300MW having a fixed cost of $120m This line can be further expanded up to 2000MW with a variable expansion cost of $0.25m/MW
7 to 1	NT(7-1)	Proposed new international transmission line with an initial carrying capability of 300MW having a fixed cost of $95m This line can be further expanded up to 2000MW with a variable expansion cost of $0.2m/MW

Similar to Country 1 the information about the existing and proposed generation stations for each country is summarized in Table 4.1. It is noted that there are no existing proposals for new generating capacity in Country 2. Countries 4 and 5 both have excess generating capacity with significant generation coming from combined cycle stations (using natural gas). Countries

6 and 7 are dominant hydropower countries and also have excess capacity but this time it is excess hydropower. Both countries 6 and 7 have proposals for the construction of new further hydropower generating capacity.

It is possible at present for Country 1 to import up to a maximum of 100MW from Country 2 (Figure 4.2). The existing line can have its existing load carrying capability increased up to a maximum of 2000MW. There is also a proposed totally new international transmission line for connecting Country 1 with Country 7. The initial capacity of this new line is 300MW. The capacities of the existing international lines are shown for between countries 1, 2, 3, and 4, in Figure 4.2. All of the existing and proposed new transmission lines can be expanded up to a maximum load carrying capability of 2000MW.

Table 4.3 Supplies of Natural Gas in the Generic Model

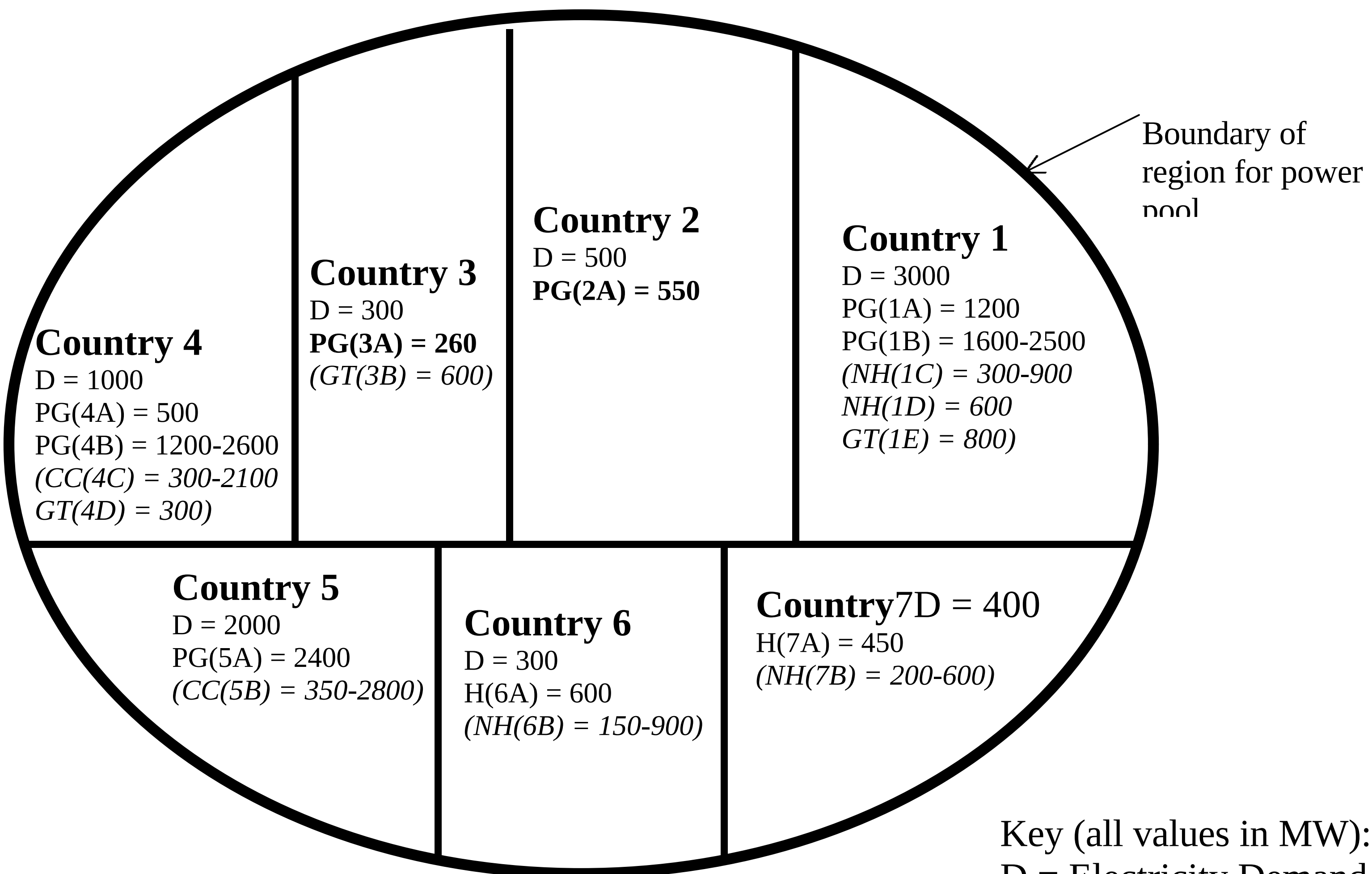
Country	Existing Supplies of Natural Gas (mmscfd – millions of cubic feet per day)	Proposed Maximum Supplies of Natural Gas (mmscfd)	Combined Cycle Generating capacity, Existing – Proposed (MW)
Country 4	200	790	1200 – 4700
Country 5	60	470	350 - 2800

Notes: Assuming that 100mmscfd will generate 600MW of combined cycle.
Only Countries 4 and 5 have access to natural gas supplies. The other countries have no natural gas available to them except that a gas pipe-line be built from Country 4 or 5. The generic model in this manual does not provide the option of the expansion of a pipe-line to the other countries.

There are no options to construct natural gas pipe-lines to all parts of the region. Table 4.3 summarizes the status of existing and proposed maximum supplies of natural gas to the region.

The mix of fuels in the region is broad. Existing old thermal stations (1A, 1B, 2A, 3A and 4A) can be described as either oil or coal fired. The fuel costs and heat rates will reflect the fuel characteristics. Old thermal station 4B is the only existing combined cycle station using natural gas. Station 4B can expand its capacity to use more gas and Country 5 also has the potential for large combined cycle generation. The capital costs (fixed and variable) for generation expansion will determine whether hydro, solid fuels or gas usage is to be further increased. The costs of the interconnecting transmission lines will determine the ease or difficulty of trade, depending on the capital fixed and variable costs for increased transmission capacity.

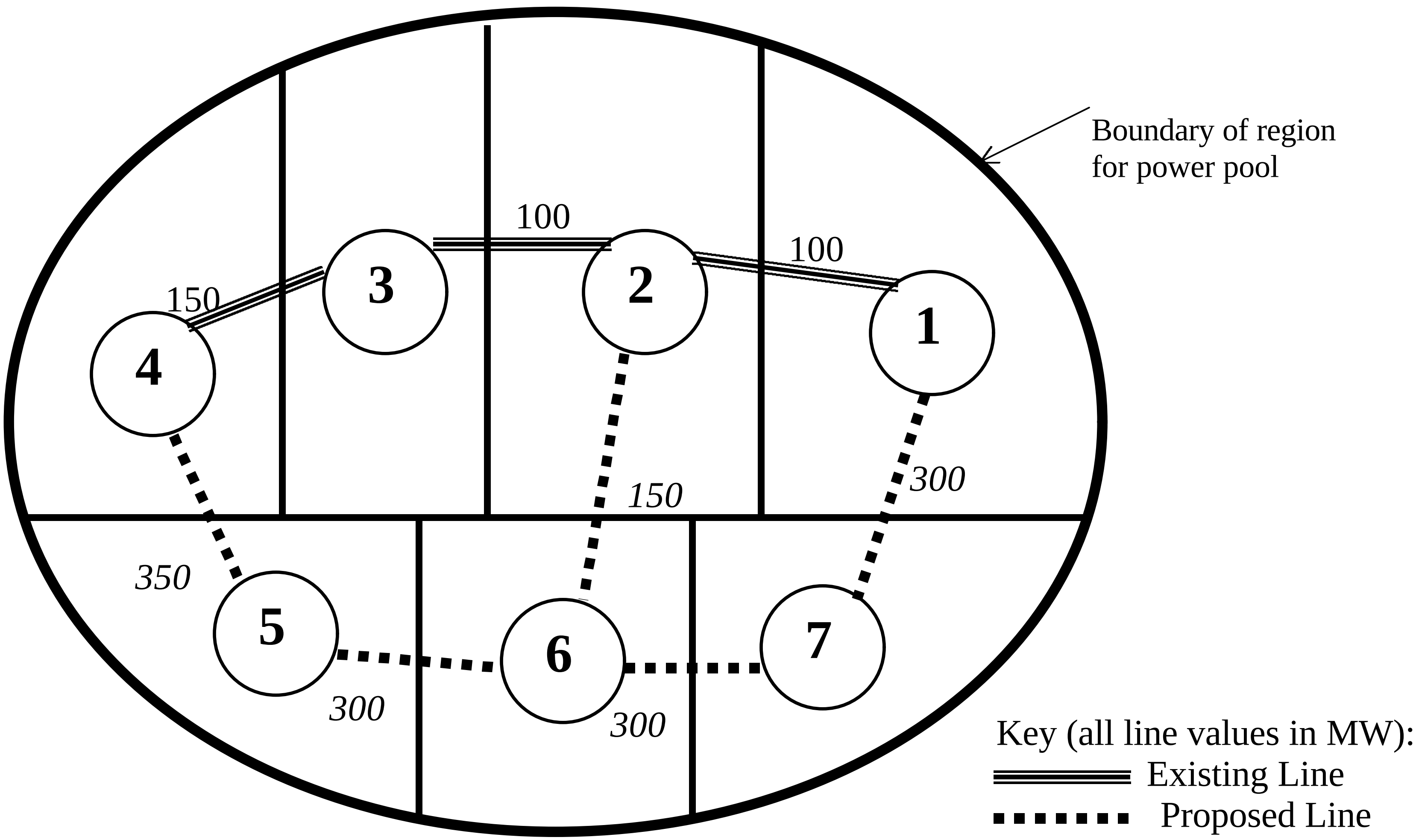
Figure 4.1 **Training Model with Peak Demand (D) & Existing Generation (PG, CC, H) for Each Country**



(Italicized values are proposed capacity expansions

Key (all values in MW):
D = Electricity Demand
PG = Old thermal/oil generation
CC= Old Combined Cycle generation
H = Old hydropower generation

Figure 4.2 **Training Model with Existing International Transmission Lines and Proposed New Lines**



Italicized values are proposed new line expansions (MW)
All lines can expand up to 2000MW

4.2 Demonstration Results from the Generic Model

Three demonstration electricity policy scenarios are provided based on a ten year planning horizon:

Scenario #1: Base case is the free trade scenario with all demand growths set at 4%.
Scenario #2: 100% autonomy factors – no trade in energy or reserves.
Scenario #3: Free trade with all countries having a demand growth of 8%.

The projects (generation and transmission) optimally selected under these three scenarios are summarized in section 4.3. These are the project output files from running each scenario. A summary of the results is shown below in Table 4.2.

Table 4.2 Summary of Projects Selection for the Three Policy Scenarios

	Scenario #1	*Scenario #2*	*Scenario #3*
Total regional cost ($billion)	**5.59**	**8.07**	**8.81**
Generation Expansions (MW)			
Old Thermal	0	900	2300
New Combined Cycle	3150	2575	4955
New Hydropower	1614	1080	1634
New Gas Turbines	462	741	1700
Total:	**5226**	**5296**	**10589**
Transmission Expansion (MW)			
Old Transmission	572	4	4599
New Transmission	3460	317	3318
Total:	**4032**	**321**	**7917**

There is a 44% increase in total regional costs when the countries adopt a 100% autonomy policy.

The generation and transmission expansions almost double in magnitude when there is regional 8% growth rate in demand (in each country) compared with the 4% rate.

In the base case scenario it is cheaper to build new thermal and hydropower generation than to expand existing thermal power stations. With 100% autonomy and little new transmission and no trade it becomes essential for the old thermals to be expanded.

In both free trade scenarios (1 and 3) the amount on new hydropower generation expansion remains the same at about 1600MW.

With the 8% regional growth there is a 700% increase in old transmission line capacity.

4.3 Demonstration Outputs from the Generic Model

4.3.1 GENERIC 7 COUNTRY MODEL
SCENARIO #1, BASE CASE SCENARIO: - All demand growths set at 4%

Program Execution Date 10/25/00
Solver Status = NORMAL COMPLETION
Model Status = OPTIMAL SOLUTION FOUND

CHOSEN PROJECTS

Total Cost = $5597107274.07
Each Period = 5 years
Const. Cost is the Construction Cost in Undiscounted Dollars

COMBINED CYCLE PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co5	NS1	350 MW	$ 4.05E+8
Total			350 MW	$ 4.05E+8

COMBINED CYCLE EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per1	co5	NS1	2800 MW	$ 1.76E+9
Total			2800 MW	$ 1.76E+9

GAS TURBINE PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per2	co1	NS1	462 MW	$ 1.38E+8
Total			462 MW	$ 1.38E+8

NEW HYDRO PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	newh1	186 MW	$ 3.71E+8
per1	co1	newh2	368 MW	$ 5.21E+8
per1	co6	newh1	93 MW	$ 1.36E+8
per1	co7	newh1	41 MW	$ 5.57E+7
per2	co1	newh1	1 MW	$ 1.85E+6
per2	co1	newh2	2 MW	$ 2.60E+6
per2	co6	newh1	0 MW	$ 6.80E+5
per2	co7	newh1	0 MW	$ 2.78E+5
Total			691 MW	$ 1.09E+9

NEW HYDRO EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	newh1	371 MW	$ 3.34E+8
per1	co6	newh1	464 MW	$ 5.11E+8
per1	co7	newh1	83 MW	$ 1.07E+8

per2	co1	newh1	2 MW	$ 1.67E+6
per2	co6	newh1	2 MW	$ 2.55E+6
per2	co7	newh1	0 MW	$ 5.35E+5
Total			923 MW	$ 9.57E+8

NEW TRANSMISSION PROJECTS

Period	Between	Capacity Added	Const. Cost
per1	co1 and co7	127 MW	$ 4.03E+7
per1	co2 and co6	15 MW	$ 8.80E+6
per1	co4 and co5	151 MW	$ 4.31E+7
per1	co5 and co6	287 MW	$ 3.83E+7
per1	co6 and co7	120 MW	$ 4.82E+7
per2	co5 and co6	13 MW	$ 1.73E+6
per2	co6 and co7	10 MW	$ 3.94E+6
Total		723 MW	$ 1.84E+8

NEW TRANSMISSION EXPANSION

Period	Between	Capacity Added	Const. Cost
per1	co1 and co7	847 MW	$ 1.69E+8
per1	co2 and co6	20 MW	$ 3.00E+6
per1	co4 and co5	862 MW	$ 1.38E+8
per1	co6 and co7	803 MW	$ 2.01E+8
per2	co5 and co6	138 MW	$ 3.04E+7
per2	co6 and co7	66 MW	$ 1.64E+7
Total		2737 MW	$ 5.58E+8

OLD TRANSMISSION EXPANSION

Period	Between	Capacity Added	Const. Cost
per1	co1 and co2	74 MW	$ 1.48E+7
per1	co3 and co4	98 MW	$ 1.47E+7
per2	co2 and co3	154 MW	$ 3.86E+7
per2	co3 and co4	245 MW	$ 3.68E+7
Total		572 MW	$ 1.05E+8

4.3.2 GENERIC 7 COUNTRY MODEL
SCENERIO #2 : 100% Autonomy factors

Program Execution Date 10/25/00
Solver Status = NORMAL COMPLETION
Model Status = OPTIMAL SOLUTION FOUND

CHOSEN PROJECTS

Total Cost = $8070548906.52
Each Period = 5 years
Const. Cost is the Construction Cost in Undiscounted Dollars

OLD THERMAL EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	Stat2	515 MW	$ 2.58E+8
per2	co1	Stat2	385 MW	$ 1.92E+8
Total			900 MW	$ 4.50E+8

COMBINED CYCLE PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co5	NS1	234 MW	$ 2.71E+8
per2	co5	NS1	116 MW	$ 1.34E+8
Total			350 MW	$ 4.05E+8

COMBINED CYCLE EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per1	co5	NS1	1874 MW	$ 1.18E+9
per2	co5	NS1	351 MW	$ 2.21E+8
Total			2225 MW	$ 1.40E+9

GAS TURBINE PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co3	NS1	130 MW	$ 4.04E+7
per2	co1	NS1	521 MW	$ 1.56E+8
per2	co3	NS1	90 MW	$ 2.80E+7
Total			741 MW	$ 2.25E+8

NEW HYDRO PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	newh1	186 MW	$ 3.71E+8
per1	co1	newh2	368 MW	$ 5.21E+8
per1	co7	newh1	16 MW	$ 2.17E+7
per2	co1	newh1	1 MW	$ 1.85E+6
per2	co1	newh2	2 MW	$ 2.60E+6
per2	co7	newh1	34 MW	$ 4.62E+7
Total			606 MW	$ 9.65E+8

NEW HYDRO EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	newh1	371 MW	$ 3.34E+8
per1	co7	newh1	32 MW	$ 4.19E+7
per2	co1	newh1	2 MW	$ 1.67E+6
per2	co7	newh1	68 MW	$ 8.90E+7
Total			474 MW	$ 4.67E+8

NEW TRANSMISSION PROJECTS

Period	Between	Capacity Added	Const. Cost
per1	co6 and co7	5 MW	$ 1.91E+6
per2	co2 and co6	19 MW	$ 1.13E+7
per2	co4 and co5	33 MW	$ 9.39E+6
per2	co6 and co7	2 MW	$ 7.64E+5
Total		59 MW	$ 2.34E+7

NEW TRANSMISSION EXPANSION

Period	Between	Capacity Added	Const. Cost
per1	co6 and co7	32 MW	$ 7.95E+6
per2	co2 and co6	26 MW	$ 3.87E+6
per2	co4 and co5	188 MW	$ 3.00E+7
per2	co6 and co7	13 MW	$ 3.18E+6
Total		258 MW	$ 4.50E+7

OLD TRANSMISSION EXPANSION

Period	Between	Capacity Added	Const. Cost
per1	co2 and co3	4 MW	$ 9.47E+5
Total		4 MW	$ 9.47E+5

4.3.3 GENERIC 7 COUNTRY MODEL
Scenario #3: All demand growths set at 8%

Program Execution Date 10/25/00
Solver Status = NORMAL COMPLETION
Model Status = OPTIMAL SOLUTION FOUND

CHOSEN PROJECTS

Total Cost = $8817755529.98
Each Period = 5 years
Const. Cost is the Construction Cost in Undiscounted Dallars

OLD THERMAL EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per2	co1	Stat2	900 MW	$ 4.50E+8
per2	co4	Stat2	1400 MW	$ 8.40E+8
Total			2300 MW	$ 1.29E+9

COMBINED CYCLE PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co5	NS1	350 MW	$ 4.05E+8
per2	co4	NS1	226 MW	$ 1.65E+8
Total			576 MW	$ 5.70E+8

COMBINED CYCLE EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per1	co5	NS1	2800 MW	$ 1.76E+9
per2	co4	NS1	1579 MW	$ 8.68E+8
Total			4379 MW	$ 2.63E+9

GAS TURBINE PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	NS1	412 MW	$ 1.24E+8
per2	co1	NS1	388 MW	$ 1.16E+8
per2	co3	NS1	600 MW	$ 1.86E+8
per2	co4	NS1	300 MW	$ 9.75E+7
Total			1700 MW	$ 5.24E+8

NEW HYDRO PROJECTS

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	newh1	186 MW	$ 3.71E+8
per1	co1	newh2	368 MW	$ 5.21E+8
per1	co6	newh1	93 MW	$ 1.36E+8
per1	co7	newh1	41 MW	$ 5.57E+7
per2	co1	newh1	1 MW	$ 1.85E+6
per2	co1	newh2	2 MW	$ 2.60E+6

per2	co5	newh5	20 MW	$ 0.00
per2	co6	newh1	0 MW	$ 6.80E+5
per2	co7	newh1	0 MW	$ 3.59E+5
Total			711 MW	$ 1.09E+9

NEW HYDRO EXPANSION

Period	Country	Station	Capacity Added	Const. Cost
per1	co1	newh1	371 MW	$ 3.34E+8
per1	co6	newh1	464 MW	$ 5.11E+8
per1	co7	newh1	83 MW	$ 1.07E+8
per2	co1	newh1	2 MW	$ 1.67E+6
per2	co6	newh1	2 MW	$ 2.55E+6
per2	co7	newh1	1 MW	$ 6.91E+5
Total			923 MW	$ 9.57E+8

NEW TRANSMISSION PROJECTS

Period	Between	Capacity Added	Const. Cost
per1	co1 and co7	128 MW	$ 4.06E+7
per1	co2 and co6	11 MW	$ 6.68E+6
per1	co4 and co5	83 MW	$ 2.37E+7
per1	co5 and co6	300 MW	$ 4.00E+7
per1	co6 and co7	138 MW	$ 5.51E+7
Total		660 MW	$ 1.66E+8

NEW TRANSMISSION EXPANSION

Period	Between	Capacity Added	Const. Cost
per1	co1 and co7	854 MW	$ 1.71E+8
per1	co2 and co6	15 MW	$ 2.28E+6
per1	co4 and co5	474 MW	$ 7.59E+7
per1	co5 and co6	181 MW	$ 3.99E+7
per1	co6 and co7	918 MW	$ 2.30E+8
per2	co5 and co6	215 MW	$ 4.72E+7
Total		2658 MW	$ 5.66E+8

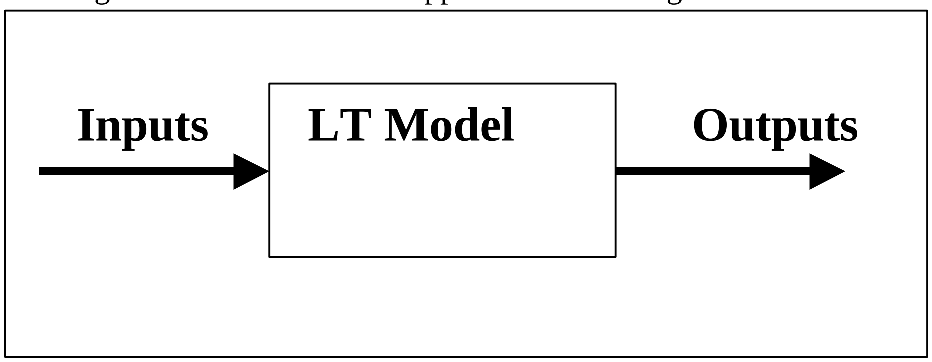
OLD TRANSMISSION EXPANSION

Period	Between	Capacity Added	Const. Cost
per1	co2 and co3	91 MW	$ 2.27E+7
per1	co3 and co4	274 MW	$ 4.11E+7
per2	co1 and co2	1138 MW	$ 2.28E+8
per2	co2 and co3	1683 MW	$ 4.21E+8
per2	co3 and co4	1414 MW	$ 2.12E+8
Total		4599 MW	$ 9.24E+8

Section 5
Inputs and Outputs to the Model

From the perspective of the general user of the long-term planning model the actual model with its formulation and coding can be treated with a "black box". The general policy user is to be concerned only with the data inputs and the resulting outputs (Figure 5.1). Detailed descriptions of results from the Southern Africa are available [4-6].

Figure 5.1 General Users Approach to the Long-Term Model



The long-term model has been tested extensively with the input data supplied by the Southern African Power Pool (SAPP) and Figure 5.2 shows the input and output file names as they were organized in June 2000. With each world region or power pool that is modeled then the names of the output files will of course also change in order to report the results for each new country that is in the model. The structure and number of the input files will not change so significantly. One significant addition since June 2000 is the inclusion of a natural gas sub-model to the LT electricity trading and expansion model.

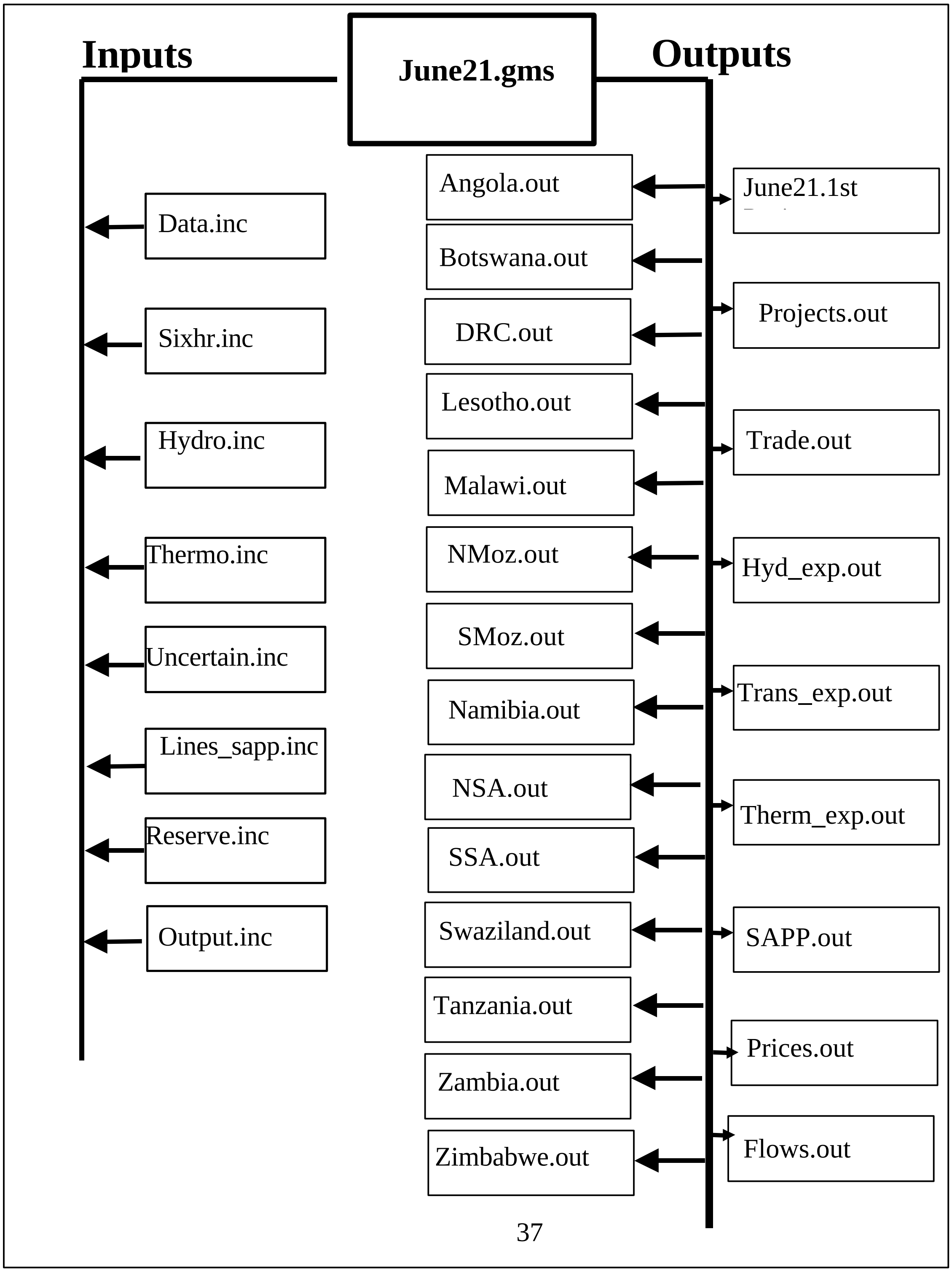
A brief description of the functions of the input and output files follows. It is recommended that the windows interface is used by the general user. This interface is described at the end of the User Manual together with illustrations of the windows options that are available. The use of the interface makes the model very user friendly and prevents the introduction of errors from inexperienced editors of the basic model coding.

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

The input and output files are briefly described here:

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

Figure 5.2 The Files that Comprise the Southern African Long-Term - Model June 21 2000



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(17) SAPP.out – Regional output reports.

(18) Prices.out – Trade pricing analysis.

(19) Flows.out – Export/Import flows

5.2 Weighting of the Seasons, Days, and Hours

Consider how do we change the number of day types in each year? We do not actually change the number of day types but we can change the weightings. The model has three day types – peak day, off-peak day, and average day. The total number of days must always add up to 365. Weightings for the days are shown in Table 5.1.

The SAPP model uses a 25:75 weighting for the winter and summer seasons. There are three types of days: peak day, average day, and off-peak day. There are 12 average night hours and 12 day hours; 8 average hours, and 4 peak hours.

Table 5.1 Weighting of Seasons, Days and Hours

				Weights					
Type	**Season**	**Day**	**Hour**	**Season**	**Day**	**Hour**	**Total Hours**	**Percent**	**Cumm.**
1	Summer	Average	Avdy	0.75	260	12	2340	26.79%	26.79%
2	Summer	Average	Avnt	0.75	260	8	1560	17.86%	44.64%
3	Winter	Average	Avdy	0.25	260	12	780	8.93%	53.57%
4	Winter	Average	Avnt	0.25	260	8	520	5.95%	59.52%
5	Summer	Peak	Avdy	0.75	52	12	468	5.36%	64.88%
6	Summer	OffPeak	Avdy	0.75	52	12	468	5.36%	70.24%
7	Summer	Peak	Avnt	0.75	52	8	312	3.57%	73.81%
8	Summer	OffPeak	Avnt	0.75	52	8	312	3.57%	77.38%
9	Summer	Average	Hr9	0.75	260	1	195	2.23%	79.61%
10	Summer	Average	Hr19	0.75	260	1	195	2.23%	81.85%
11	Summer	Average	Hr20	0.75	260	1	195	2.23%	84.08%
12	Summer	Average	Hr21	0.75	260	1	195	2.23%	86.31%
13	Winter	Peak	Avdy	0.25	52	12	156	1.79%	88.10%
14	Winter	OffPeak	Avdy	0.25	52	12	156	1.79%	89.88%
15	Winter	Peak	Avnt	0.25	52	8	104	1.19%	91.07%
16	Winter	OffPeak	Avnt	0.25	52	8	104	1.19%	92.26%
17	Winter	Average	Hr9	0.25	260	1	65	0.74%	93.01%
18	Winter	Average	Hr19	0.25	260	1	65	0.74%	93.75%
19	Winter	Average	Hr20	0.25	260	1	65	0.74%	94.49%
20	Winter	Average	Hr21	0.25	260	1	65	0.74%	95.24%
21	Summer	Peak	Hr9	0.75	52	1	39	0.45%	95.68%
22	Summer	Peak	Hr19	0.75	52	1	39	0.45%	96.13%
23	Summer	Peak	Hr20	0.75	52	1	39	0.45%	96.58%
24	Summer	Peak	Hr21	0.75	52	1	39	0.45%	97.02%
25	Summer	OffPeak	Hr9	0.75	52	1	39	0.45%	97.47%
26	Summer	OffPeak	Hr19	0.75	52	1	39	0.45%	97.92%
27	Summer	OffPeak	Hr20	0.75	52	1	39	0.45%	98.36%
28	Summer	OffPeak	Hr21	0.75	52	1	39	0.45%	98.81%
29	Winter	Peak	Hr9	0.25	52	1	13	0.15%	98.96%
30	Winter	Peak	Hr19	0.25	52	1	13	0.15%	99.11%
31	Winter	Peak	Hr20	0.25	52	1	13	0.15%	99.26%
32	Winter	Peak	Hr21	0.25	52	1	13	0.15%	99.40%
33	Winter	OffPeak	Hr9	0.25	52	1	13	0.15%	99.55%
34	Winter	OffPeak	Hr19	0.25	52	1	13	0.15%	99.70%
35	Winter	OffPeak	Hr20	0.25	52	1	13	0.15%	99.85%
36	Winter	OffPeak	Hr21	0.25	52	1	13	0.15%	100.00%
							8736	100.00%	

	Season		
SAPP	Winter	0.25	SAPP Winter makes up 1/4 of the year.
SAPP	Summer	0.75	SAPP Summer makes up 3/4 of the year.
	Day		
	Peak	52	52 days a year are classified as Peak days.
	Average	260	260 days a year are classified as Average days.
	Offpeak	52	52 days a year are classified as OffPeak days.
	Hour		
	Avnt	8	8 hours a day are classified as Average Night hours
	Hr9	1	Hr9 corresponds to the 9th hour of the day.
	Avdy	12	12 hours a day are classified as Average Night hours
	Hr19	1	Hr19 corresponds to the 9th hour of the day.
	Hr20	1	Hr20 corresponds to the 9th hour of the day.
	Hr21	1	Hr21 corresponds to the 9th hour of the day.

Section 6
Template Data Collection Sheets

Supply, Demand, & Shipment (Existing & Proposed)

The Purdue electricity and gas trade model optimizes the minimum cost to meet the demands for electricity and natural gas within one region over a long-term horizon (e.g., 20 years). The region consists of several or more countries (indexed as z or zp). Normally each country is modeled as one node. Free trade is permitted to take place between all of the countries in the specified region. The total demand and supply of energy (electricity and natural gas) has to be known for each node/country. The shipping capacity (of electricity and natural gas) between any two nodes/countries has to be known. Data for the existing and potentially new supply points (new generation stations, new gas wells, new transmission and new gas pipelines) are all needed. The existing demand at each node and the forecast for electricity growth in demand are required. The percentage of the natural gas supplied to each node for electricity generation and the percentage for other needs are required for each year in the model. (More than one node for each country can be created if shown to be necessary).

Electricity Forecast - Annual Sent Out Load

Country: ………………………………..

A Yearly Data

A1 Annual Peak Demand (MW)
Projected by year, 1998-2020

A2 Annual Energy Use (GWh)
Projected by year, 1998-2020

	MW			GWh
1998			1998	
1999			1999	
2001			2001	
2002			2002	
2003			2003	
2004			2004	
2005			2005	
2006			2006	
2007			2007	
2008			2008	
2009			2009	
2010			2010	
2011			2011	
2012			2012	
2013			2013	
2014			2014	
2015			2015	
2016			2016	
2017			2017	
2018			2018	
2019			2019	
2020			2020	

B Weekly peak load (MW) for the most recent year
Year: ……………

1		11		21		31		42	
2		12		22		32		43	
3		13		23		33		44	
4		14		24		34		45	
5		15		25		35		46	
6		1		26		336		47	
7		17		27		37		48	
8		18		28		38		49	
9		19		29		39		50	
10		20		30		40		51	
						41		52	

Electricity Load Forecast

C Hourly Data (MW) for a Representative Week, in the most recent year

(24 x 7 = 168 values)

Year: ……………, Week Number: ………

DAY & MW load each hour

Hour	Sun	Mon	Tues	Weds	Thurs	Fri	Sat
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							

D 8760 Hour Load (MW) Data File for the most recent year
As an alternative to B and C this one year 8760 (52 x 7 x 24) hour data file can be supplied. *Please attach* the appropriate sheets with all 8760 hours of data.

Hour	Load (MW)								Hour	Load (MW)
1										
2										
3									8758	
etc									8759	
									8760	

Electricity - Existing Thermal Station

Country: …………………………………   Station Name: ………………………………

Plant Type: …………………………………………………………..
(Coal, oil fired combustion turbine, gas fired combustion turbine, gas fired combined cycle)

Operating Status: …………………………………………….
(in operation, shut-down, mothballed, other)

Number of Units: …………………………….   Load type (base, cycling, peak): …………………………….

Comment	Value	Parameter
1. Current net effective (dependable) sent out capacity (MW)		PGOinit
2. Expansion costs dollar per MW of old plants ($/MW)		Oexpcost
3. Expansion step size for old thermo plants units (MW)		PGOexpstep
4. Max possible MW addition to existing thermo plants (MW)		PGOmax
5. Force outage rate for existing thermo units (fraction)		FORPGO
6. Unforced outage rate for existing thermo plants (fraction)		UFORPGO
7. Capital recovery factor for existing thermals (fraction/year)		crfi
8. Variable O&M for old thermal plants ($/MWh)		VarOMoh
9. Heat rate of old thermo plant set equal to one		HRO
10. Fuel cost of Existing thermo plant ($/MWh)		fpO
11. Escalation rate of fuel costs of old thermo plants (fraction/year)		fpescO
12. Decay rate of old thermo plants (fraction/year)		decayPGO
13. Old thermal minimum usage in MWh per year		PGmin
14. Forced Decommissioning AT period ty		Fdecom
15. Capacity Factor (%)		
16. Date of Station Installation		
17. Remaining Economic Life (years)		
18. SO_2 content (lbs per million Btu of fuel input)		
19. NO_x content (lbs per million Btu of fuel input)		
20. CO_2 content (lbs per million Btu of fuel input)		
21. Mercury content (lbs per million Btu of fuel input)		
22. Particulates content (lbs per million Btu of fuel input)		
23. Ash content (lbs per million Btu of fuel input)		

Electricity - Existing Hydro Station

Country: ………………………………… Station Name: ………………………………

Plant Type: …………………………………… Operating Status: ……………………………………..

Number of Units: ……………………………. Load type: …………………………………………….

Comment	Value	Parameter
1. Initial capacity of an existing hydro station (MW)		Hoinit
2. Capital cost of additional capacity for existing hydro ($/MW)		HOVcost
3. Expansion step for existing hydro (MW)		Hoexpstep
4. Maximum MW expansion that can be added (MW)		HOVmax
5. Annual MWh allowed at an existing dam (normal conditions) (MWh/yr)		HOLF
6. Annual MWh allowed at an existing dam (drought conditions) (MWh/yr)		
7. Forced outage rate for existing hydro plant (fraction/year)		FORoh
8. Capital recovery factor for an existing hydro plant (fraction/year)		Crfih
9. Variable O&M cost for old hydro ($/MWh)		VarOMoh
10. Decay rate of old hydro plants (fraction/year)		DecayHO
11. Reserve margin for hydro plants (fraction)		Reshyd
12. Old hydro minimum usage in MWh per year		MinH
13. Forced decommissioning AT period ty		FdecomH
14. Capacity Factor (%)		
15. Date of Station Installation		
16. Remaining Economic Life (years)		

Electricity - New Thermal, Small Coal, Station (< 500MW)

Country: ………………………………… Station Name: ………………………………

Plant Type: …………………………………… Operating Status: ……………………………………..

Number of Units: ……………………………. Load type: ……………………………………………

Comment	Value	Parameter
1. Fixed costs, site purchase preparation & infrastructure ($)		FGSC
2. Expansion costs of new small coal plants ($/MW)		NSCexpcost
3. Transmission integration cost ($)		
4. Expansion step size for new small coal plants (MW)		NSCexpstep
5. Maximum expansion for a small coal plant (MW)		PGNSCmax
6. Forced outage rate for small coal plants (fraction)		FORNSC
7. Unforced outage rate for small coal plants (fraction)		UFORNSC
8. Capital recovery factor for new thermal (fraction/year)		Crfni
9. Variable O&M cost for small coal plants ($/MWh)		OMSC
10. Fixed O&M cost for small coal plants ($/MW/year)		FixOMSC
11. Heat rate of new small coal plants 1000000 BTU's/MWh		HRNSC
12. Fuel costs of new small coal plants $/1000000 BTU's		FpNSC
13. Escalation rate of fuel cost of new small coal plants (fraction/year)		FpescNSC
14. Decay rate of small coal plants (fraction/year)		DecayNSC
15. Small coal built AT period ty		AtSC
16. Small coal NOT built BEFORE or AT period ty		BefSC
17. Small coal minimum usage in MWh's per year		AftSC
18. Small coal minimum usage in MWh's per year		MinSC
19. Earliest date to be placed on line		
20. Expected economic life (years)		
21. SO_2 content (lbs per million Btu of fuel input)		
22. NO_x content (lbs per million Btu of fuel input)		
23. CO_2 content (lbs per million Btu of fuel input)		
24. Mercury content (lbs per million Btu of fuel input)		
25. Particulates content (lbs per million Btu of fuel input)		
26. Ash content (lbs per million Btu of fuel input)		

Electricity - New Thermal, Large Coal, Station (≥ 500MW)

Country: ………………………………… Station Name: ………………………………
Plant Type: …………………………………… Operating Status: ……………………………………..
Number of Units: ……………………………. Load type: …………………………………………….

Comment	Value	Parameter
1. Fixed costs, site purchase preparation & infrastructure ($)		FGLC
2. Initial capacity of new large coal plants (MW)		PGNLCinit
3. Expansion costs of new large coal plants ($/MW)		NLCexpcost
4. Transmission integration cost ($)		
5. Expansion step size for new large coal plants (MW)		NLCexpstep
6. Maximum expansion for a large coal plant (MW)		PGNLCmax
7. Forced outage rate for large coal plants (fraction)		FORNLC
8. Unforced outage rate for large coal plants (fraction)		UFORNLC
9. Capital recovery factor for new thermal (fraction/year)		Crfni
10. Variable O&M cost for large coal plants ($/MWh)		OMLC
11. Fixed O&M cost for large coal plants ($/MW/year)		FixOMLC
12. Heat rate of new large coal plants 1000000 BTU's/MWh		HRNLC
13. Fuel costs of new large coal plants $/1000000BTU's		FpNLC
14. Escalation rate of fuel cost of new large coal (fraction/year)		FpescNLC
15. Decay rate of large coal plants (fraction/year)		DecayNLC
16. Large coal MUST be built AT period ty. 0 is unconstrained		AtLC
17. Large coal MUST be built BEFORE period ty. 0 if unconstrained		BefLC
18. Large coal MUST NOT be built BEFORE or AT period ty. 0 if unconstrained		AftLC
19. Large coal minimum usage in MWh per year		MinLC
20. Earliest date to be placed on line		
21. Expected economic life (years)		
22. SO_2 content (lbs per million Btu of fuel input)		
23. NO_x content (lbs per million Btu of fuel input)		
24. CO_2 content (lbs per million Btu of fuel input)		
25. Mercury content (lbs per million Btu of fuel input)		
26. Particulates content (lbs per million Btu of fuel input)		
27. Ash content (lbs per million Btu of fuel input)		

Electricity - New Thermal, Gas Turbine, Station

Country: ………………………………… Station Name: ………………………………
Plant Type: …………………………………… Operating Status: ……………………………………..
Number of Units: ……………………………. Load type: …………………………………………….

Comment	Value	Parameter
1. Fixed costs, site purchase preparation & infrastructure ($)		FGGT
2. Expansion costs new gas turbine plants ($/MW)		Ntexpcost
3. Transmission integration cost ($)		
4. Expansion step size for new gas turbine plants (MW)		Ntexpstep
5. Maximum expansion for a combustion turbine plant (MW)		PGNTmax
6. Forced outage rate for combustion turbine plants (fraction)		FORNT
7. Unforced outage rate for combustion turbine plants (fraction)		UFORNT
8. Capital recovery factor for new thermal (fraction/year)		Crfni
9. Variable O&M cost for combustion turbine plants ($/MWh)		OMT
10. Fixed O&M cost for gas turbine plants ($/MW/year)		FixOMT
11. Heat rate of new combustion turbine plant 1000000 BTU's/MWh		HRNT
12. Fuel costs of new gas turbine $/1000000 BTU's		FpNT
13. Escalation rate of fuel cost of new gas turbine (fraction/year)		FpescNT
14. Decay rate of gas turbine plants (fraction /year)		DecayNT
15. Turbine built AT period ty		AtT
16. Turbine built BEFORE or AT period ty		BefT
17. Turbine NOT built BEFORE or AT period ty		AftT
18. Turbine minimum usage in MWh's per year		MinT
19. Earliest date to be placed on line		
20. Expected economic life (years)		
21. SO_2 content (lbs per million Btu of fuel input)		
22. NO_x content (lbs per million Btu of fuel input)		
23. CO_2 content (lbs per million Btu of fuel input)		
24. Mercury content (lbs per million Btu of fuel input)		
25. Particulates content (lbs per million Btu of fuel input)		
26. Ash content (lbs per million Btu of fuel input)		

Electricity - New Thermal, Combined Cycle, Station

Country: ………………………………… Station Name: ………………………………
Plant Type: …………………………………… Operating Status: ……………………………………..
Number of Units: ……………………………. Load type: …………………………………………….

Comment	Value	Parameter
1. Fixed costs, site purchase preparation & infrastructure ($)		FGCC
2. Expansion costs of new combined cycle plants ($/MW)		NCCexpcost
3. Transmission integration cost ($)		
4. Expansion step size for combined cycle plants (MW)		NCCexpstep
5. Initial capacity of new combined cycle plants (MW)		PGNCCinit
6. Maximum expansion for a combined cycle plant (MW)		PGNCCmax
7. Forced outage rate for combined cycle plants (fraction)		FORNCC
8. Unforced outage rate for combined cycle plants (fraction)		UFORNCC
9. Capital recovery factor for new thermal (fraction/year)		Crfni
10. Variable O&M cost for combined cycle plants ($/MWh)		OMCC
11. Fixed O&M cost for combined cycle plants ($/MW/year)		FixOMCC
12. Heat rate of new combined cycle plants 1000000 BTU's/MWh		HRNCC
13. Fuel costs of new combined cycle plants $/1000000 BTU's		FpNCC
14. Escalation rate of fuel cost of new combined cycle plants (fraction/year)		FpescNCC
15. Decay rate of combined cycle plants (fraction/year)		DecayNCC
16. Combined cycle built AT period ty		AtCC
17. Combined cycle built BEFORE or AT period ty		BefCC
18. Combined cycle NOT built BEFORE or AT period ty		AftCC
19. Combined cycle minimum usage in MWh per year		MinCC
20. Earliest date to be placed on line		
21. Expected economic life (years)		
22. SO_2 content (lbs per million Btu of fuel input)		
23. NO_x content (lbs per million Btu of fuel input)		
24. CO_2 content (lbs per million Btu of fuel input)		
25. Mercury content (lbs per million Btu of fuel input)		
26. Particulates content (lbs per million Btu of fuel input)		
27. Ash content (lbs per million Btu of fuel input)		

Electricity - New Hydro Station

Country: ………………………………… Station Name: ………………………………

Plant Type: …………………………………… Operating Status: ……………………………………..

Number of Units: ……………………………. Load type: ……………………………………………….

Comment	Value	Parameter
1. Initial step capacity of new hydro stations (MW)		Hninit
2. Fixed capital cost of initial step, site purchase, infrastructure (US $)		HNFcost
3. Capital cost of additional capacity for new hydro ($/MW)		HNVcost
4. Transmission integration cost ($)		
5. Maximum possible MW expansion added to a new hydro station (MW)		HNVmax
6. Expansion step size for new hydro stations (MW)		Hnexpstep
7. Annual MWh allowed at a new dam (MWh/year)		HNLF
8. Forced outage rate for new hydro plants (fraction)		FORnh
9. Capital recovery factor for a new hydro plant (fraction/year)		Crfnh
10. Fixed O&M cost for new hydro ($/year)		FixOMnh
11. Variable O&M cost for new hydro ($/MWh)		VarOMnh
12. Decay rate of new hydro plants (fraction/year)		DecayHN
13. New hydro built AT period ty		AtHn
14. New hydro built BEFORE or AT period ty		BefHn
15. New hydro NOT built BEFORE or AT period ty		AftHn
16. New hydro minimum usage in MWh per year		MinHN
17. Earliest date to be placed on line		
18. Expected economic life (years)		

Electricity - Existing Transmission Line

Countries (z,zp): ……………………………………………………………

Comment	Value	Parameter
1. Tie line capacities (MW)		PFOinit
2. Type, AC or DC		
3. Cost per MW of expanding existing line in (mill $)		PFOVc
4. Line Voltage (kV)		
5. Route length (km)		
6. Capital recovery factor for transmission lines (fraction/year)		crf
7. Losses at practical transfer power (%)		PFOloss
8. Practical transfer power, country z to zp (MW)		
9. Practical transfer power, country zp to z (MW)		
10. Maximum MW expansions that can be added to existing lines (MW)		PFOVmax
11. Annual forced outage rate for existing transmission line (%)		FORICO
12. Annual unforced outage rate for existing transmission line (%)		
13. Or Annual maintenance duration (weeks per year)		
14. Decay rate of old lines (fraction/year)		DecayPFO
15. Minimum power flow on old line (MW)		minPFO
16. Date placed on line		
17. Expected remaining life (years)		

Note: Practical transfer power is the power which can be transferred taking into account all system limitations e.g. Stability, voltage limits, etc

Electricity - Proposed Transmission Line

Countries (z,zp): …………………………………………………

Comment	Value	Parameter
1. Initial tie lines capacity for new line (MW)		PFNinit
2. Type, AC or DC		
3. Line Voltage (kV)		
4. Route length (km)		
5. Capital recovery factor for transmission lines (fraction/year)		Crf
6. New tie line fixed cost, Engineering, procurement & construction (mill US $)		PFNFc
7. Cost of additional capacity on new line (wire cost) (mill $/MW)		PFNVc
8. Maximum MW expansions that can be added to a new tie line (MW)		PFNVmax
9. Transmission loss factor on new lines (%)		PFNloss
10. Practical transfer power, country z to zp (MW)		
11. Practical transfer power, country zp to z (MW)		
12. Annual forced outage rate for new transmission line (%)		FORICN
13. Annual unforced outage rate for new transmission line (%)		
14. Or Annual maintenance duration (weeks per year)		
15. Decay rate of new lines (fraction/year)		DecayPFN
16. Minimum power flow on a new line (MW)		MinPFN
17. Line built AT period ty		Atlines
18. Line NOT built BEFORE or AT period ty		Aftlines
19. Line built BEFORE or AT period ty		Beflines
20. Earliest date to be placed on line		
21. Expected economic life (years)		

Note: Practical transfer power is the power which can be transferred taking into account all system limitations e.g. Stability, voltage limits, etc

Electricity - Existing Hydro Pumped Station

Country: ………………………………… Station Name: ………………………………

Plant Type: …………………………………… Operating Status: ……………………………………..

Number of Units: ……………………………. Load type: …………………………………………….

Comment	Value	Parameter
1. Decay rate of an existing pumped hydro (fraction/year)		Decay PHO
2. Existing pumped storage loss coefficient (fraction)		PSOloss
3. MW capacity of existing pumped hydro station (MW)		PGPSOinit

Electricity - New Hydro Pumped Storage Station

Country: ………………………………… Station Name: ………………………………

Plant Type: …………………………………… Operating Status: ……………………………………..

Number of Units: ……………………………. Load type: …………………………………………….

Comment	Value	Parameter
1. Fixed site purchase preparation & infrastructure cost ($)		
2. Transmission integration cost ($)		
3. Expansion costs of new plant ($/MW)		
4. Decay rate of a new pumped hydro (fraction/year)		DecayPHN
5. New pumped storage loss coefficient (fraction)		PSNloss
6. Initial MW capacity of proposed new pumped hydros (MW)		PHNinit
7. New PS hydro reservoir volume capacity (MWh/day)		HDPSNmwh
8. Capital recovery factor for new pumped storage hydro plants (fraction/year)		Crfphn
9. Fixed O&M cost for new pumped storage ($/year)		FixOMph
10. Variable O&M cost for pumped storage ($/MWh)		VarOMph
11. Pumped hydro fixed capital cost (US$)		Phncost
12. Earliest date to be placed on line		
13. Expected economic life (years)		

Electricity - Existing/New Nuclear Station

Country: …………………………………   Station Name: ………………………………

Plant Type: ……………………………………   Operating Status: ……………………………………..

Number of Units: ……………………………   Load type: …………………………………………….

Comment	Value	Parameter
1. Fixed site purchase preparation & infrastructure cost ($)		
2. Expansion costs of new plant ($/MW)		
3. Transmission integration cost ($)		
4. Current capacity of plant (MW)		PGOinit
5. Expansion costs dollar per MW of plant ($/MW)		Oexpcost
6. Expansion step size for units (MW)		PGOexpstep
7. Max possible MW addition to existing plant (MW)		PGOmax
8. Force outage rate for units (fraction)		FORPGO
9. Unforced outage rate for plant (fraction)		UFORPGO
10. Capital recovery factor for new plant (fraction/year)		Crfi
11. Variable O&M for plant ($/MWh)		VarOMoh
12. Heat rate of plant		HRO
13. Fuel costs of plant ($/MWh)		FpO
14. Escalation rate of fuel costs of plant (fraction/year)		FpescO
15. Decay rate of plant (fraction/year)		DecayPGO
16. Minimum usage in MWh per year		Pgmin
17. Forced Decommissioning AT period ty		Fdecom
18. Earliest date for new plant to be placed on line		
19. Expected economic life (years)		

Natural Gas - Demand

Country (Node): ………………………………..

Year	Demand for Natural Gas, at node, from all other sources except that which is used for electricity generation (10^9 Btu/yr – billions of Btu per year)
2000	
2001	
2002	
2003	
2004	
2005	
2006	
2007	
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	

Natural Gas – Existing Pumping Supply Well

Country (Node): ………………………………..

	Value	Parameter
1. Name of gas pumping well:		
2. Total Reserve at well: (10^9 Cu ft – billions of cubic feet)		
3. Hourly Pumping Well Capacity: (10^6 Btu/hr – millions of Btu per hour)		GasInit(z,gw)
4. Calorific Value of gas: (10^3 Btu/Cu ft – thousands of Btu per cubic foot)		
5. Well Pumping/Operating Cost: ($\$/10^6$ Btu – USD per million Btu)		GWCost(z,gw)
6. Pumping well location: (Please supply a map showing the location of the well – a sketch will suffice that illustrates the country boundaries & the location of major cities)		

Natural Gas – Existing Pipeline

Countries (z,zp): …………………………………………………

	Value	Parameter
1. Name at point of origin of pipeline (z)		
2. Name at finishing point of pipeline (zp)		
3. Name of pipeline (z,zp)		
4. Length of pipeline: (miles)		
5. Pipeline hourly capacity: (10^6 Btu/hr – millions of Btu per hour between z & zp))		PipeCap(z,zp)
6. Pipeline shipment cost: ($/10^6$ Btu – USD per million Btu)		GSpCst(z,zp)
7. Cost of holding inventory: ($/10^6$ Btu/day - USD per million Btu per day at point z)		InvCst(z)
7. Pipeline gas leakage rate: (% of gas pumped at z that does not arrive at point zp)		PFGloss(z,zp)
8. Pipeline location: (Please supply a map showing the location of the pipeline – a sketch will suffice that illustrates the country boundaries & the location of major cities)		

Natural Gas – Proposed/New Pipeline

Countries (z,zp): ………………………………………………………

	Value	Parameter
1. Name at point of origin of pipeline (z)		
2. Name at finishing point of pipeline (zp)		
3. Name of pipeline (z,zp)		
4. Length of pipeline: (miles)		
5. Pipeline hourly capacity: (10^6 Btu/hr – millions of Btu per hour between z & zp))		PipeCap(z,zp)
6. Pipeline shipment cost: (\$/10^6 Btu – USD per million Btu)		GSpCst(z,zp)
7. Cost of holding inventory: (\$/10^6 Btu/day - USD per million Btu per day at point z)		InvCst(z)
5. Pipeline gas leakage rate: (% of gas pumped at z that does not arrive at point zp)		PFGloss(z,zp)
6. Pipeline location: (Please supply a map showing the location of the pipeline – a sketch will suffice that illustrates the country boundaries & the location of major cities)		
12. Pipeline capital cost: (\$$10^6$ – millions of USD for new line between z and zp)		PipeCost(z,zp)
13. Pipeline capital recovery factor: (% - crf percentage for new line between z and zp)		Crfg(z,zp)

Section 7
Modeling Notation

LT-Model Notation ***(April 14, 2000)***

(Equation Names Excluded)

Name-Notation	**Definition-Comment**
A	
AF(z,ty)	Autonomy factor for country *z* in period *ty* (fraction).
AftCC(ty,z,ni)	Combined cycle plant cannot be built before or at year *ty*.
AftHn(ty,z,nh)	New hydro plant cannot be built before or at year *ty*.
AftLC(ty,z,ni)	Large coal plant cannot be built before or at year *ty*.
Aftlines(ty,z,zp)	New line cannot be built before or at year *ty*.
AftSC(ty,z,ni)	Small coal plant cannot be built before or at year *ty*.
AftT(ty,z,ni)	Turbine plant cannot be built before or at year *ty*.
AtCC(ty,z,ni)	Combined cycle plant must be built at period *ty*.
AtHn(ty,z,nh)	New hydro plant must be built at period *ty*.
AtLC(ty,z,ni)	Large coal plant must be built at period *ty*.
Atlines(ty,z,zp)	New line must be built at period *ty*.
AtSC(ty,z,ni)	Small coal plant must be built at period *ty*.
AtT(ty,z,ni)	Turbine plant must be built at period *ty*.
B	
Base(ts,td,th.z)	Base year demand in season *ts*, day *td*, hour *th*, in country *z*. (MW)
BefCC(ty,z,ni)	Combined cycle plant must be built before or at period *ty*.
BefHn(ty,z,nh)	New hydro plant must be built before or at period *ty*.
BefLC(ty,z,ni)	Large coal plant must be built before or at period *ty*.
Beflines(ty,z,zp)	New line must be built before or at period *ty*.
BefSC(ty,z,ni)	Small coal plant must be built before or at period *ty*.
BefT(ty,z,ni)	Turbine plant must be built before or at period *ty*.
C	
crf(z,zp)	Capital recovery factor for transmission lines (fraction per year).
crfi(z,i)	Capital recovery factor for existing thermal plants (fraction per year).
crfih(z,ih)	An existing hydro plant's capital recovery factor (fraction per year).
crfnh(z,nh)	Capital recovery factor for a new hydro plant (fraction per year).
crfni(z,ni)	Capital recovery factor for new thermal plants (fraction per year).
crfphn(z,phn)	Capital recovery factor for new pumped storage hydro plants (fraction per year).
crfum	Capital recovery factor for unserved MW's.
D	
DecayHN	Decay rate of new hydro plants (fraction per year).
DecayHO	Decay rate of existing hydro plants (fraction per year).
DecayNCC	Decay rate of new combined cycle plants (fraction per year).
DecayNLC	Decay rate of new large coal plants (fraction per year).

DecayNSC	Decay rate of new small coal plants (fraction per year).
DecayNT	Decay rate of new gas turbine plants (fraction per year).
DecayPFN	Decay rate of new lines (fraction per year).
DecayPFO	Decay rate of existing lines (fraction per year).
DecayPGO	Decay rate of existing thermal plants (fraction per year).
DecayPHN	Decay rate of new pumped hydro (fraction per year).
DecayPHO	Decay rate of existing pumped hydro (fraction per year).
dgr(z,ty)	Demand growth for a specific country in a specific period *ty* (fraction per period).
dgrowth1(z)	Demand growth rate for period 1 (fraction per year).
dgrowth2(z)	Demand growth rate for period 2 (fraction per year).
dgrowth3(z)	Demand growth rate for period 3 (fraction per year).
dgrowth4(z)	Demand growth rate for period 4 (fraction per year).
dgrowth5(z)	Demand growth rate for period 5 (fraction per year).
dgrowth6(z)	Demand growth rate for period 6 (fraction per year).
dgrowth7(z)	Demand growth rate for period 7 (fraction per year).
dgrowth8(z)	Demand growth rate for period 8 (fraction per year).
dgrowth9(z)	Demand growth rate for period 9 (fraction per year).
dgrowth10(z)	Demand growth rate for period 10 (fraction per year).
disc	Discount rate (fraction per year).
DLC(z)	Domestic loss coefficient for each region (1 plus fraction).
DW	Equal to *n*.
Dyr(ty,ts,td,th,z)	Demand in year *ty*, *ts*, *td*, *th*, in country *z*, equal to base year demand times growth rate.
E	
Enaf(z,ty)	Energy autonomy factor for country *z* in *ty*.
F	
fdrought(ty,z)	Reduced water flow during drought. 1 = Normal and <1 is dry (fraction).
Fdecom(z,i)	The period in which decommissioning is forced for old thermal plants.
FdecomH(z,ih)	The period in which decommissioning is forced for old hydro plants.
FGCC(z,ni)	Fixed cost for new combined cycle plants ($).
FGLC(z,ni)	Fixed cost for new large coal plants ($).
FixOMCC(z,ni)	Fixed *O&M* cost for combined cycle plants ($/MW/yr).
FixOMLC(z,ni)	Fixed *O&M* cost for large coal plants ($/MW/yr).
fixOMnh(z,nh)	Fixed *O&M* cost for new hydro ($/MW/yr).
fixOMph(z,phn)	Fixed *O&M* cost for pumped storage ($/MW/yr).
FixOMSC(z,ni)	Fixed *O&M* cost for small coal plants ($/MW/yr).
FixOMT(z,ni)	Fixed *O&M* cost for gas turbine plants ($/MW/yr).
Fmax(ty,zp,z)	Reserves held by country *zp* for country *z* during period *ty* (MW)
Fmax(ty,z,zp)	Reserves held by country *z* for country *zp* during period *ty* (MW).
FORICN(z,zp)	Forced outage rate for new transmission lines (fraction).
FORICO(z,zp)	Forced outage rate for existing transmission lines (fraction).
FORNCC(z,ni)	Forced outage rate for new combined cycle plants (fraction).
FORnh(z,nh)	Forced outage rate for new hydro plants (fraction).
FORNLC(z,ni)	Forced outage rate for new large coal plants (fraction).
FORNSC(z,ni)	Forced outage rate for new small coal plants (fraction).
FORNT(z,ni)	Forced outage rate for new gas turbine plants (fraction).
FORoh(z,ih)	Forced outage rate for existing hydro plants (fraction).

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

I

i	Indice for an existing thermal plant.
ih	Indice for an existing hydro plant.

J

j	Indice for pumped hydro station.

L

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

M

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

N

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

O

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

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

	turbine plants [integer or continuous variable].
PGNTexp(tye,z,ni)	Number of units of the given expansion step size installed in *tye* for new gas turbine plants [integer or continuous variable].
PGNTmax(z,ni)	Maximum MW that can be added to a new turbine plant (MW).
PGOcapcost(ty)	Expansion cost of all existing thermal plant ($)[variable].
PGOexp(tyb,z,i)	Expansion of existing thermal plants in *tyb* [variable].
PGOexpstep(z,i)	Expansion step size for existing thermal plant units (MW).
PGOinitTY(z,i,ty)	Current capacity for existing thermal plants in *ty* (MW).
PGOmax(z,i)	Maximum MW that can be added to an existing thermal plant (MW).
PGPSN(ty,ts,td,th,z,phn)	Electricity production level of a new pumped storage plant (MW) [variable].
PGPSO(ty,ts,td,th,z)	Electricity production level of an existing pumped storage plant (MW) [variable].
PGPSOinit(z)	Existing pumped hydro capacity (MW).
phn	Indice for proposed new pumped hydro.
PHNcapcost(ty)	Cost of new pumped storage installed in *ty* ($)[variable].
PHNFcost(z,phn)	Pumped hydro fixed capital cost ($).
PHNinit(z,phn)	Initial capacity of proposed new pumped hydros (MW).
PSNloss(phn)	New pumped storage loss coefficient (fraction).
PSOloss	Existing pumped storage loss coefficient (fraction).
PUPSN(ty,ts,td,th,z,phn)	Electricity consumption level of a new pumped storage plant (MW) [variable].
PUPSO(ty,ts,td,th,z)	Electricity consumption level of an existing pumped storage plant (MW) [variable].
R	
reshyd(z)	Reserve margin of hydro plants for each country (fraction).
resthm(z)	Reserve margin of thermal plants for each country (fraction).
T	
td	Indice for time in days (off-peak, average, peak).
th	Indice for the time in hours (*hr9*, *avnt*, *hr19*, *hr20*, *hr21*, *avdy*).
ts	Indice for the time in seasons (summer, winter).
ty	Indice for the period.
tya	Alias of *ty*.
tyb	Alias of *ty*.
tye	Alias of *ty*.
U	
UE(ty,ts,td,th,z)	Unserved energy (MWh) [variable].
UEcost	Cost of unserved energy ($/MWh).
UFORNCC(z,ni)	Unforced outage rate for new combined cycle plants (fraction).
UFORNLC(z,ni)	Unforced outage rate for new large coal plants (fraction).
UFORNSC(z,ni)	Unforced outage rate for new small coal plants (fraction).
UFORNT(z,ni)	Unforced outage rate for new gas turbine plants (fraction).
UFORPGO(z,i)	Unforced outage rate for existing thermal plants (fraction).
UM(z,ty)	Unmet reserve requirement for country *z* in *ty* (MW) [variable].
UM(z,tye)	Unmet reserve requirement for country *z* in *tye* (MW) [variable].
UMcost	Cost of unmet reserve requirements ($/MW).
V	
VarOMoh(z,ih)	*O&M* variable cost for old hydro ($/MWh).

VarOMnh(z,nh)	*O&M* variable cost for new hydro ($/MWh).
VarOMph(z,phn)	*O&M* variable cost for pumped storage ($/MWh).
W	
wcost(z,ty)	Opportunity cost of water for country *z* in *ty* ($/MWh).
Y	
YCC(ty,z,ni)	Decision to build/not build initial step of new combined cycle plants in *ty* [binary variable].
YCC(tya,z,ni)	Decision to build/not build initial step of new combined cycle plants in *tya* [binary variable].
YCC(tye,z,ni)	Decision to build/not build initial step of new combined cycle plants in *tye* [binary variable].
Yh(ty,z,nh)	Decision to build/not build initial step of new hydro plants in *ty* [binary variable].
Yh(tye,z,nh)	Decision to build/not build initial step of new hydro plants in *tye* [binary variable].
YLC(ty,z,ni)	Decision to build/not build initial step of new large coal plants in *ty* [binary variable].
YLC(tya,z,ni)	Decision to build/not build initial step of new large coal plants in *tya* [binary variable].
YLC(tye,z,ni)	Decision to build/not build initial step of new large coal plants in *tye* [binary variable].
Yper(ty)	*Yper* = 1 if period is to be counted, otherwise *Yper* = 0.
Ypf(ty,z,zp)	Decision to build/not build initial step of new interconnector in *ty* [binary variable].
Ypf(ty,zp,z)	Decision to build/not build initial step of new interconnector in *ty* [binary variable].
Ypf(tye,z,zp)	Decision to build/not build initial step of new interconnector in *tye* [binary variable].
Yph(ty,z,phn)	Decision to build/not build initial step of pumped storage hydro in *ty* [binary variable].
Yph(tye,z,phn)	Decision to build/not build initial step of pumped storage hydro in *tye* [binary variable].
Z	
z	Indice for source country.
zp	Indice for destination country.

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