Appendix 1

A short study of an Anticyclone centred over the UK 20th to 27th December 2006

A1.0 Security of Supply

The UK has one significant electricity inter-connector with continental Europe operating between England and France. This may be contracted with the situation on the Continent where power flows freely across international boundaries.

Wind turbines are solely dependent upon the strength and consistency if they are to contribute to the 'Security of Electricity Supply'. The argument that at least a small percentage of the installed wind turbine capacity may be relied upon to contribute to the demand as the wind energy is available somewhere across the UK all the time. Therefore it is argued that it is not necessary to provide complete back-up facilities from reliable generating sources, which would significantly increase the capital investment and operating costs required to build and operate new fossil fuel stations. (It is assumed that such a service could only be delivered by fossil fuel plants)

It would be unfortunate if metrological conditions ever prevailed when there was no wind energy across the whole of the UK as energy from this source could not be readily imported from the continent.

A1.2 The Impact of an Anticyclone on Power Generation from the Wind

The wind speed must reach 4m/s (approximately 8 knots) before it commences to generate power. When the speed reaches 16m/s (approximately 31knots) the maximum power is produced and this is then held constant up to 26 m/s (approximately 51 knots). Above this speed the turbines are shut down to prevent damage to the turbine structures. Fig A1.

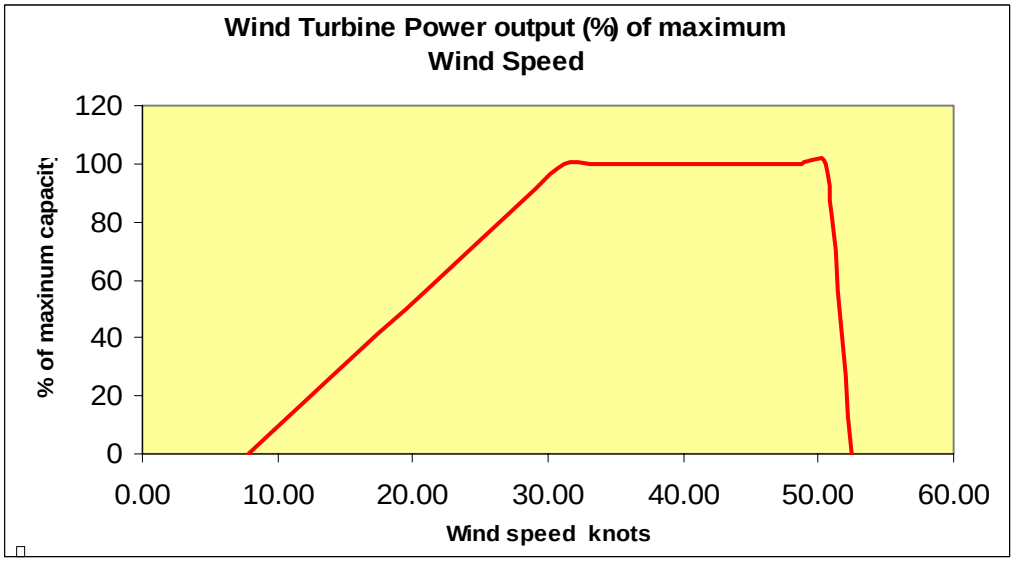


Fig A1.1 the relationship of power generated by a wind turbine against wind speed

During the period around Mid December 2006 the condition across the whole of the UK was subjected to a period of very low wind speeds. This was caused by an anti-cyclone centred over the central / southern part of England. It lasted for 6 days.

Fig A 1.2 illustrates the surface pressure map of the UK and the adjacent coastal waters on 20th December.

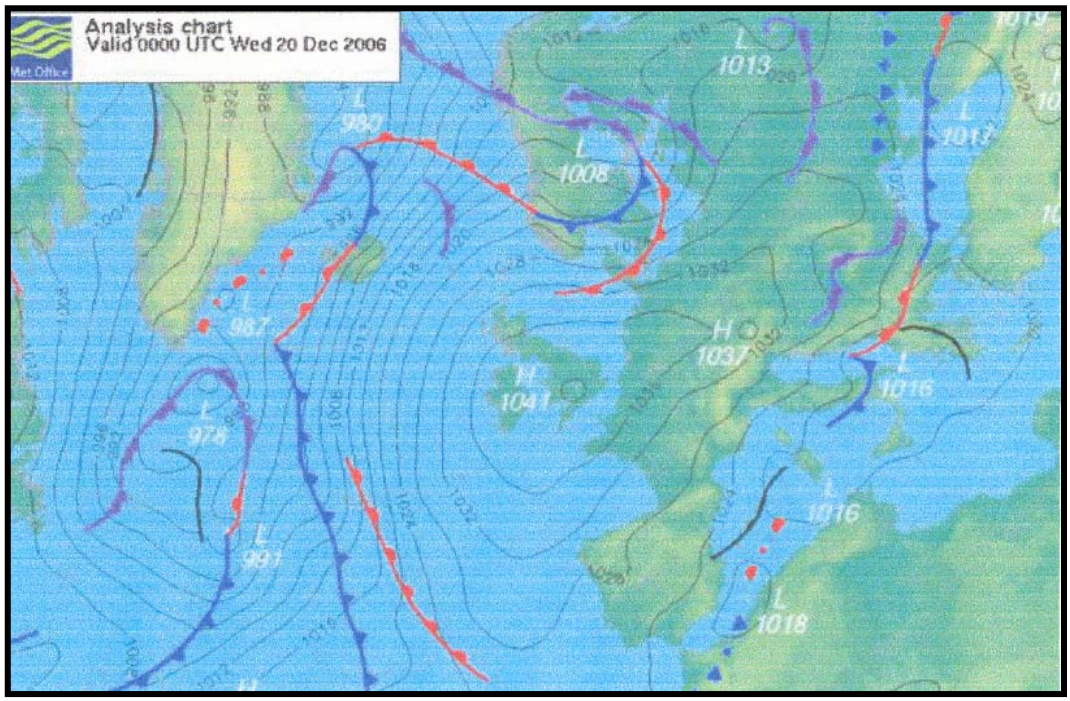


Fig A 1.2 The Pressure map for the UK (issued by the Met Office December

2006)

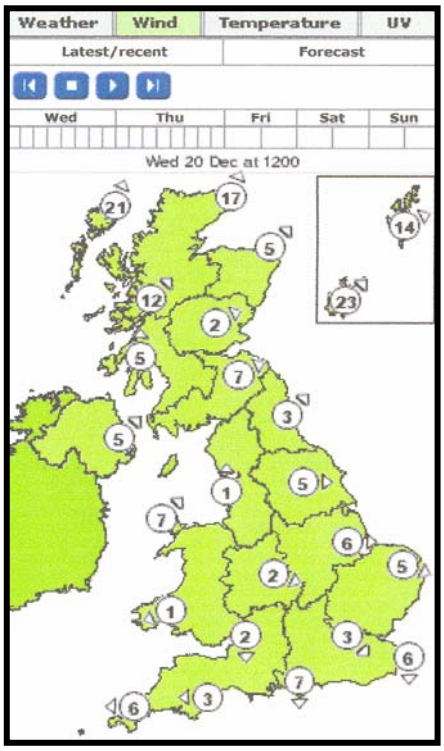


Fig A 1.3 The wind speeds for 20th Dec 2006 (Met office)

It can be seen that the wind speeds across most of the UK are all too low to generate any power. The one place where the wind could have produce power on this was the North West of Scotland where average speeds of 21 knots prevailed. But there are currently no wind farms in that area (although some are planned for the future). Even if they had been installed, from Fig. A 1.1 it can be deduced that the turbines in this location would have been unlikely to supply power at a rate equal to half the nominal installed turbine capacity at that site.

The Anticyclone remained almost stationary over the UK until 28th December when it began to drift towards central Europe and was replaced by a series of low pressure fronts. The wind speeds increased sufficiently to deliver energy to generate power at locations across the country.

The progress of the anticyclone is illustrated collectively in Fig A 1.4 (a,b,c) where the surface pressure is recorded from 20th December to the 30th December. The UK diagrams for the local wind speeds during this period are shown in Fig A 1.5.

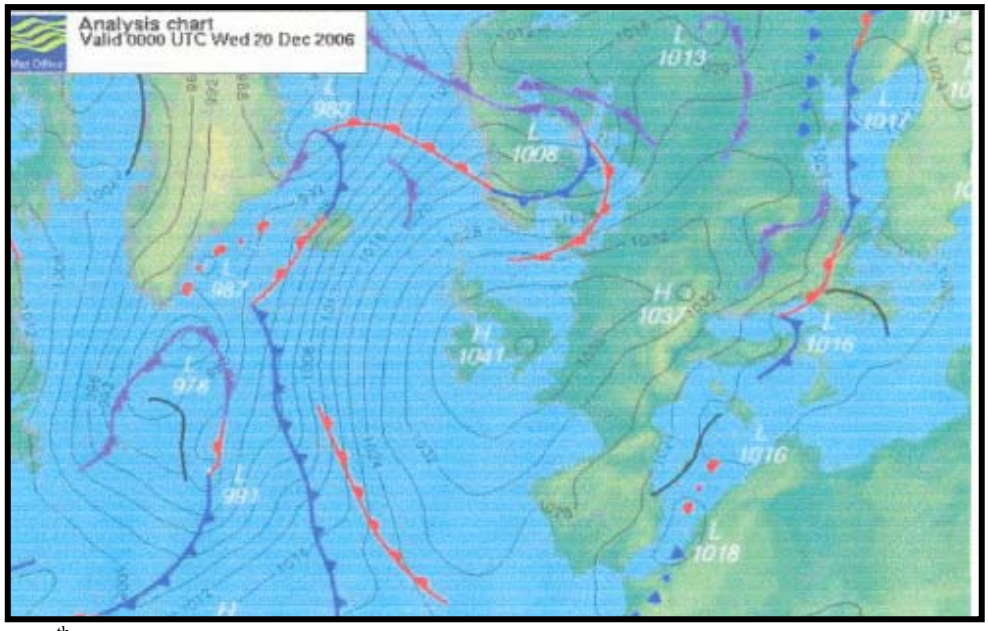
The locations of the operational wind farms in the UK (June 2006) are shown in Fig A1.6. It can be seen that none of these installations would have been producing any electrical power during the period under examination.

The periods when an anticyclone is stationary over the UK will require back-up power equal to the installed wind capacity.

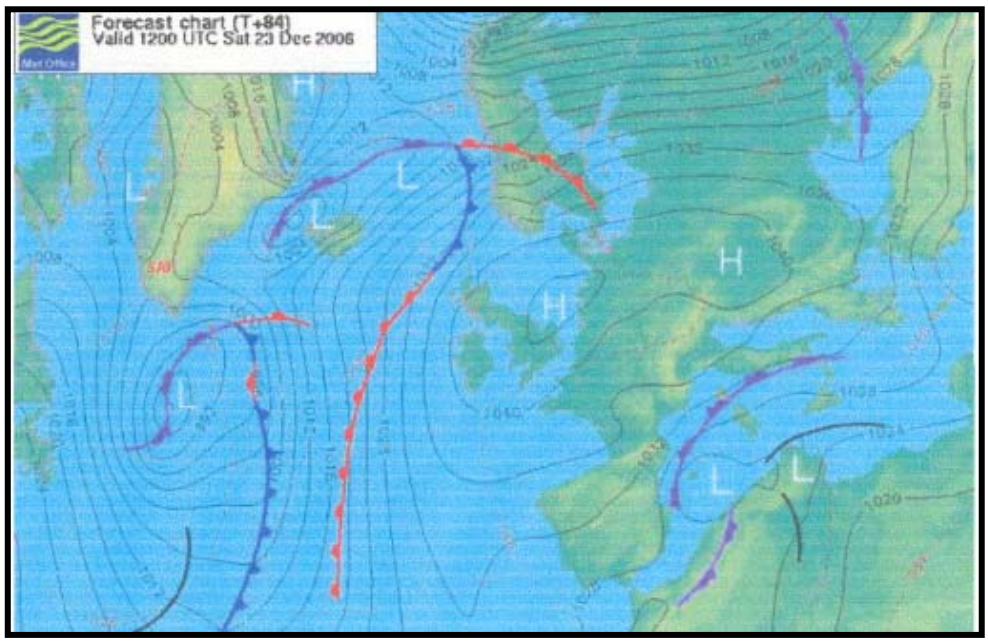
The only potential source of renewable which could provide some power during a period of zero wind power is tidal power. If a project such as the Severn barrage was available it might make a measurable contribution but there would be no guarantee that the anticyclone would occur during a time when the maximum output was available from the barrage (i.e. during a Spring tide).

It is unlikely that the replacement power will come from other renewable resources of energy. During the next 20 to 30 years, if the planned increase of wind capacity is achieved, it will far exceed the power from any other source of renewable energy.

The only current option available which can provide secure sources of power would be generated by fossil fuelled power plants. The capacity of this standby plant would need to equal the lost wind turbine capacity otherwise the security of supply could not be guaranteed.

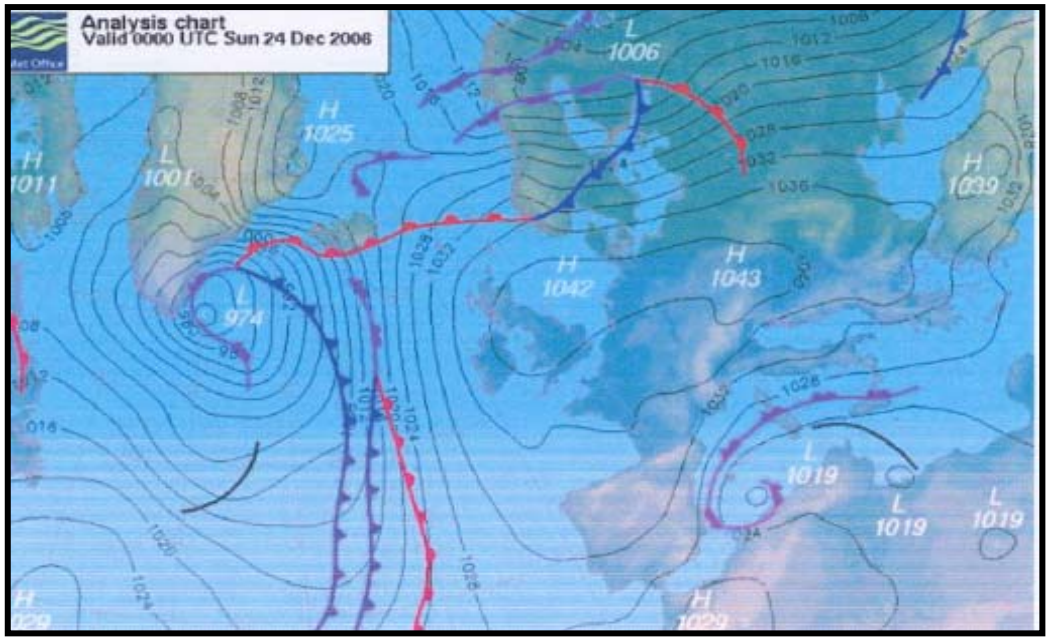


20th December

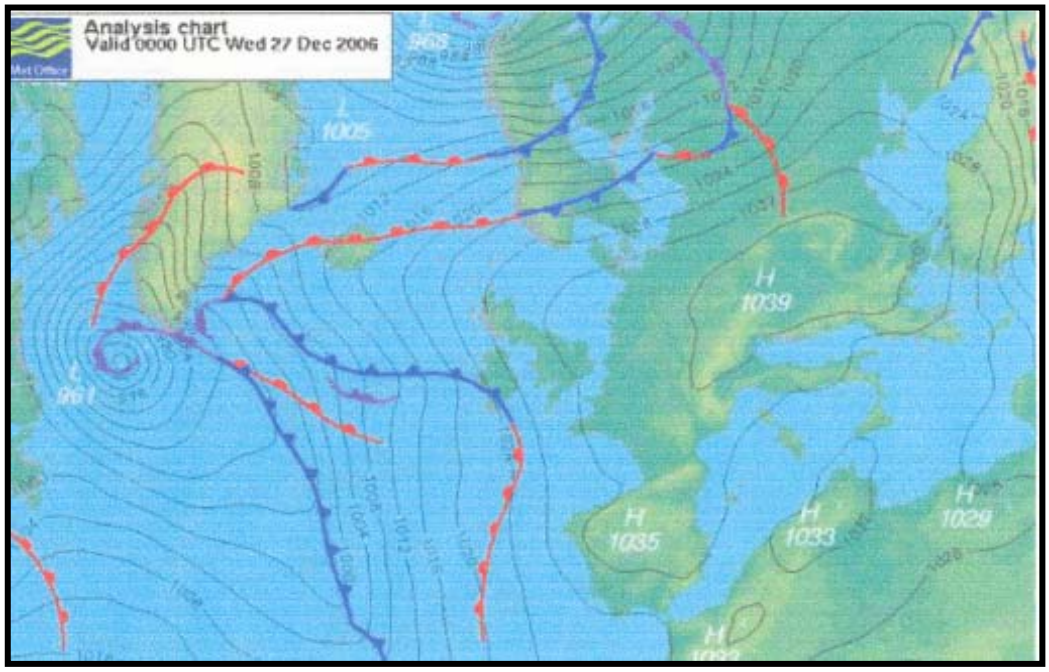


23rd December

Fig A1.4a The Surface pressure chart for the UK on 20th &23rd December 2006.

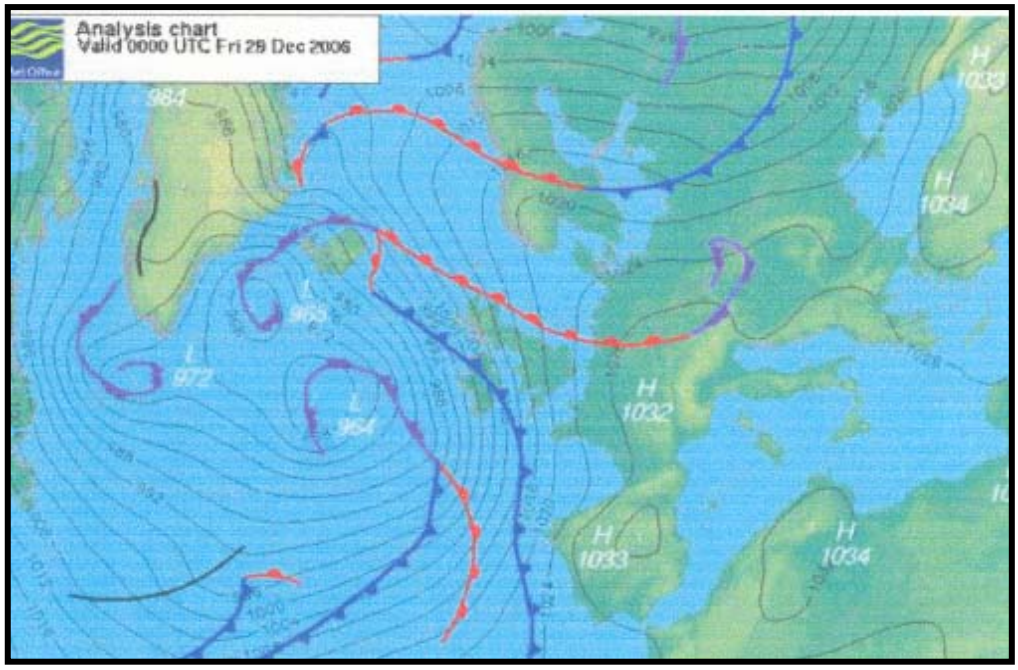


24th December

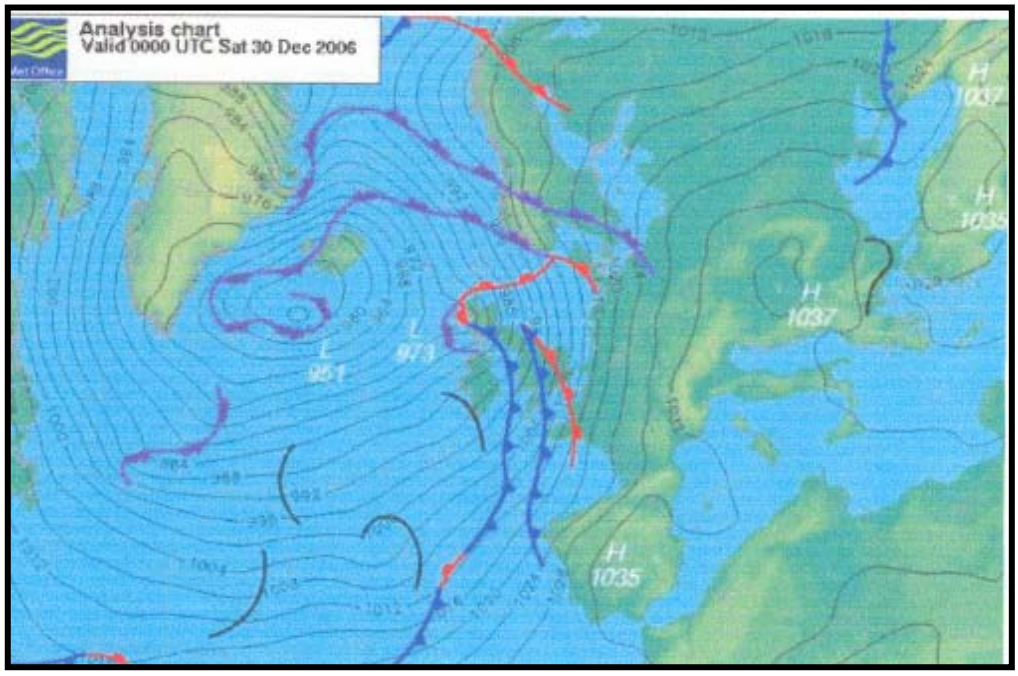


27th December

Fig A 1.4b The surface pressure charts for the UK on 24th and 27th December 2006



29th December



30th December

Fig A 1.4c The surface pressure charts for the UK 29th and 30th December 2006 (Met Office)

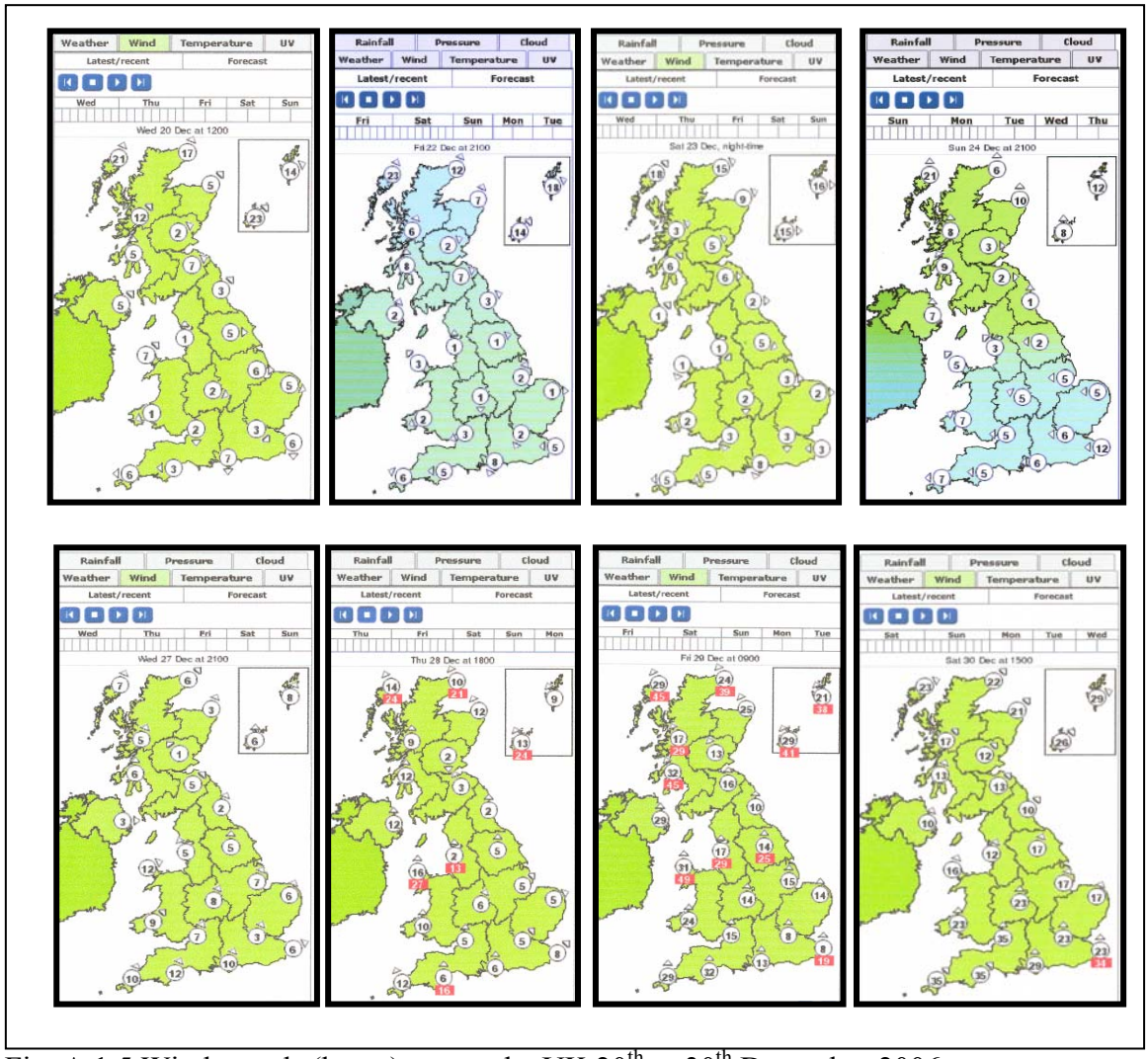


Fig A 1.5 Wind speeds (knots) across the UK 20th to 30th December 2006 (Met Office).

Fig A1.6 The operational Site of UK wind farms (June 2006) source: BWEA.

A1.3 Conclusions

The evidence presented above indicates a period of 8 to 9 days (between 20th and the 28th December 2006) when no wind energy was accessible across the whole of the UK. There was no measurable contribution to the electricity supply during the whole of this period.

Appendix A2

An analysis of the performance of a Modern Combined Cycle Gas Turbine Power station

A2 .0 Introduction

The data collected from 'Plant C' is shown at the start of each spreadsheet (Sheets 2.1 to 2.7) and a selection of the results summarised in sheet 2.8.

The performance of the plant was analysed using this data and the operational characteristics of the plant determined to identify the power output, fuel used, CO_2 emitted, and where relevant the NOx emitted.

The data was collected from the installed plant data reporting system. The accuracy of the data was within the tolerances required for statutory reporting purposes. Each set of data was recorded at 5 minute intervals during all plant operational hours.

The computational flow diagram for Chapter 3 (Appendix 2) is illustrated in Fig A2.1

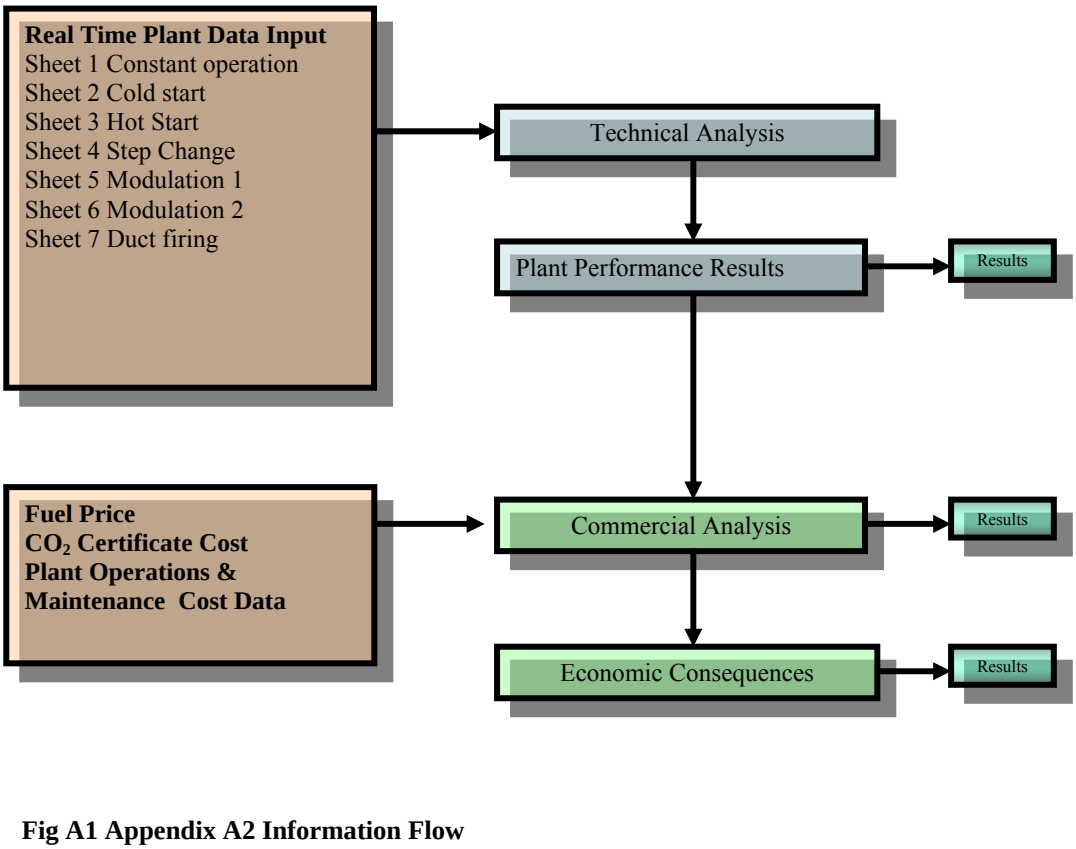


Fig A1 Appendix A2 Information Flow

Fig A2 .1 computational flow diagram.

A2.1 Plant Performance Analysis

The analysis of each set of results followed the simple routine illustrated in the logic diagram Fig A2.

The average power output during each selected period was give by:

$$Pt = \sum_{T=0}^{T=To} Pi \times 60 / 12 \qquad \text{MWh}$$

$$Pa = Pt / To \qquad \text{MWh / h}$$

Where: Pt = Power produced during test period MWh
To = Time period of test hrs
Pi = Measured power output (5 min intervals) MWh
Pa = Average power output per hour MWh

The maximum and minimum power output levels during the test period were recorded and the standard deviation of the power output computed to indicate
the degree of variation which occurred during the operation.

The fuel used, CO_2 and NOx emitted were computed with a similar routine.

The Standard Deviation of the data for each parameter was computed to indicate the spread of the input information.

The results and the comparison of the different operating patterns are recorded in chapter 3 of the main text.

A2.2 Spread Sheets for Further Reference

The calculations are shown on the following spreadsheets available in an accompanying CD ROM.

Spreadsheet	Appendix 2 Sheet 1 Constant Operation
	Appendix 2 Sheet 2 Cold Start
	Appendix 2 Sheet 3 Hot Start
	Appendix 2 Sheet 4 Step change
	Appendix 2 Sheet 5 Modulation 1
	Appendix 2 Sheet 6 Modulation 2
	Appendix 2 Sheet 7 Duct Firing
	Appendix 2 Sheet 8 Plant Performance Summary Sheet

Appendix 3

Potential Income from Energy Storage

A 3.10 Commercial Tariffs

Commercial and industrial customers may elect to purchase electricity from a number of different suppliers. They all offer a range of tariffs to attract customers with very different demand profiles.

The tariff shown in Table A3.1 has been chosen to test the potential savings which might be achieved if power was purchased during the cheapest period and used when the price was at its most expensive each 24 hour period for a whole year.

Table A 3.1 Commercial Tariff available during 2005/2006

Commercial Tariff 2006/2007	**Tariff rate p/kWh**
Night Time (00.00 to 07.00hours)	5
Weekend (07.00 to 24.00 hours)	6.1
Week Day (07.00 to 24.00 hours)	7.5
Winter Peak (16.00-19.00 hrs) (November -February)	14.5

In this example it is assumed that 1MWh is purchased at the night rate for a year. If the 'Turn Round' efficiency is 80% it will be necessary to purchase 20% more power that will be returned to the system.

Cost of input power = 0.05 X 1000 X 365 X 1.2 £ / year

= 21, 900 £ / year

The power will be used to substitute for imported power during the highest price for that day,

Hence 1 MWh will be returned when the tariff is at the day rate during the periods March to October each year and at the peak rate during November to February.

Between 0.7.00 hrs to 23.00hrs on each Saturday and Sunday the weekend rate applies. The benefits during this period are marginal and depend upon efficiency of the storage system employed. (An obvious time to carryout any maintenance work necessary).

Income (savings) from returning the stored energy (i.e. 1 MWh) during:

a) Summer day rate period (nominal number of days = 172)

Income (day rate) = 1000 X 178 X 0.075 £ / year

= 13350 £ / year

b) Winter peak rate period (nominal number of days = 85)

Income (peak rate) = 1000 X 85 X 0.145 £ / year

= 12325 £ / year

c) Weekend day rate period (nominal days = 102)

Income weekend period) = 1000 X 102 X 0.061 £ / year

= 6222 £ / year

Total Annual Income = 31,897 £ / Year

Total Gross Margin = 31897 - 21900

= £9997 £/ year

The actual contribution to the Gross Margin was made up as follows:

Winter	*£ 7225*
Summer	*£ 2670*
All Weekends	£ 102

72.25% of the potential gain is acquired during the four winter months.

A3.1 Wholesale Market Price

Large industrial customers may choose to purchase from the Half Hourly market at forward prices. The data presented in Appendix 3 sheet 1 represents the actual market price of power for each half hour period during the calendar year 2005. By selecting the maximum and minimum price of power during each 24 hour period it is possible to estimate the maximum potential gain that could be achieved in one year if 1MWh was purchased at the cheapest price and sold at during the most expensive period.

Table A3.1 illustrates the results of such operation on the period of a year which an Energy Trader could be expected to achieve after an allowance for a 20% loss during the energy storage process.

Table A3.1	(Sheet 1)		
Trader Potential	Annual Gain		
Annual Gross Revenue £	1MWh stored each 24 hours **Difference price**	**Maximum daily price 7618.81**	**Difference price 7449.14**
	16085.59		
Net Revenue £ (post 80% Turn Round Efficiency Adjustment)	**14385.13**		

A 3.20 Triad Charges

The Half Hourly metered customers are required to contribute to the costs of funding and operating the national transmission system.

The charges are levied on a number of users of the system, the generators pay an entry charge measured at their Grid Input Point and the suppliers pay an exit charge at each Grid Supply Point. The size of the charge is directly related to the maximum capacity each organisation requires to enable them to export or import the power respectively.

The third charging system is based upon the maximum demand for power imported by commercial and industrial customers during periods of the three highest national power demands recorded upon the whole network between November and February each year.

Known as 'Triads Charges', they are based upon the actual power demand which each customer was consuming during these periods. (The three peak periods must be separated by 10 days in order to remove the potential for one winter cold spell causing all three maximum demand numbers). The Triad periods almost always occur between 17.00 hours and 18.00 hours during a weekday.

If the customers are able to reduce their power demand during Triad periods, they can reduce the annual cost of their power significantly. The 2005 / 2006 the annual cost of importing 1MW during the Triad are determined by region and varies between £10,000 for customers in the Central UK regions and £20,000 for those located in the Southwest. Various Triad forecasting services exist to advise these customers of the likely periods when a maximum power demand is about to occur to enable avoiding action to be taken by disconnecting non-essential loads. However, this often involves manual intervention to select the appropriate sections of the plant and a loss of productivity on the part of the customer. As an alternative, if power could be stored on site and released into the system during potential triad periods, there would be a saving in Triad Charges and it would avoid any loss in production. Using the power storage example above of storing 1 MWh each day and releasing it back into the system at the appropriate time to avoid a Triad Charges would allow a saving to be made:

Central Region Customers

Annual Triad saving = £10,000/MW / annum

Southwest Region Customers

Annual triad saving = £23,000MW / annum

Source: NGC Document LC10 (annual charges)

A3.3 Total Annual Savings

If the saving from the tariff calculation (A 3.1) and the Triad savings (A 3.20) above are summed it would be possible to accumulate significant annual gains.

Total Annual Savings potential = Tariff savings + Triad savings

Central region = £19,997 / annum

Southwest region = £29,997 / annum

Appendix 4

Electricity Losses in the Transmission and Distribution Networks

A4.0 Introduction

The losses in transporting electricity to the customer have been investigated by examining the average power flows in the system and applying the average losses as reported by the Regulator (Ofgem).

The losses which occur during periods of maximum demand and minimum demand have been projected as % above and below the average levels.

It has also been assumed 25 % of the losses are due to fixed loss in the system. These have been considered to occur during periods when the average annual demand is flowing. The remaining losses have been considered as variable losses which respond to the i^2R rule (i.e. lower during periods below the average demand and higher during periods above the maximum demand)

As the winter demands are significantly above those during the summer, separate calculations have been performed to identify the differences. No account has been taken of ambient temperature differences (hence changing supply line resistance changes) as it is only intended to indicate the potential issues involved.

A4.1 Transmission & Distribution loss variations (sheet 1)

The model follows the computations indicated in the flow diagram Fig A 4. 1

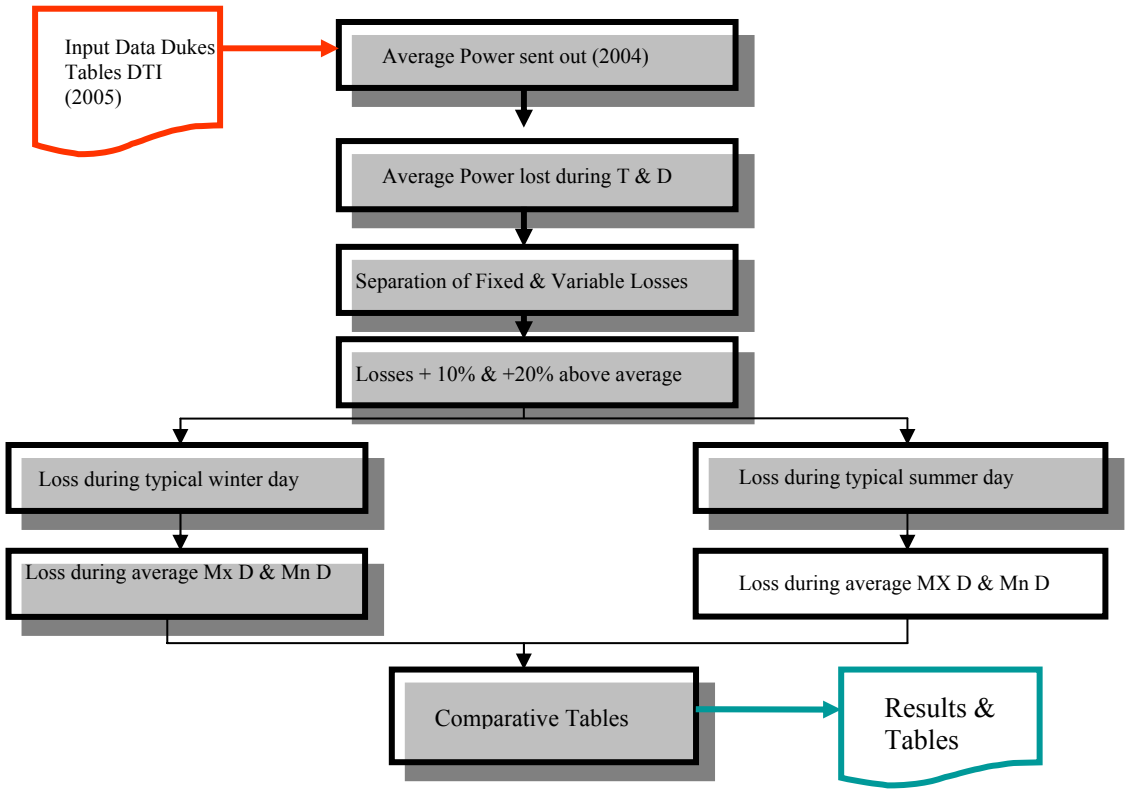


Fig 1 Appendix 4 Model Calculations

Fig. A 4.1 Model flow diagram for the T & D loss calculations

Line Item Description

(Line 30) Pa = Py / 8760

(Line 34) P LA = PL / Pa

Where:

Power Sent Out (year)	= Py	(Dukes table)	(GWh)
Average Power sent out	= Pa		(GWh)
Power Lost (year)	= Pl	(Dukes Tales)	(GWh)
Power Lost average	= Pf		(GWh)
Power Lost (variable)	= Pv		(GWh)
Power MD (2004)	= Pmd		(GW)
Increment of MD%	= Pmd%		(%)

(Line 35) Lf = PLa X 0.25 (Year) (GWh)

(Line 36) Lv = PLv X 0.75 (Year) (GWh)

(Line 49) 0 to 100 % of MD (where MD for 2004 =53GW Dukes Tables)

(Line 50) Pi = PMd% / 100 X Pmd

(Line 51) PLi = Pv X P md%^{2} / Pmd^2 + Pf (GWh)

(Line 105) Table 4.1 Losses for typical winter and summer days including Values for sectors in the network 15% above average losses

(Line 122) Table 4.2 Average winter losses for NGC and DNO(s) (for average and maximum cases)

(Line 143) Table 4.3 Average summer losses for NGC and DNO(s) (for average and maximum cases)

(Line 157) Table 4.4 Summary Average Losses and Maximum losses for DNO(s)

Tables 4.5 to 4.9 prepared for graphical presentation.

A 4.2 Optimum Location for energy storage (Sheet 2)

Computations follow the routine indicated in the flow diagram Fig A 4.2.

The spread sheet follows the logic described in 5 to examine the potential reduced losses which may be gained by the use of embedded storage located adjacent to the customer.

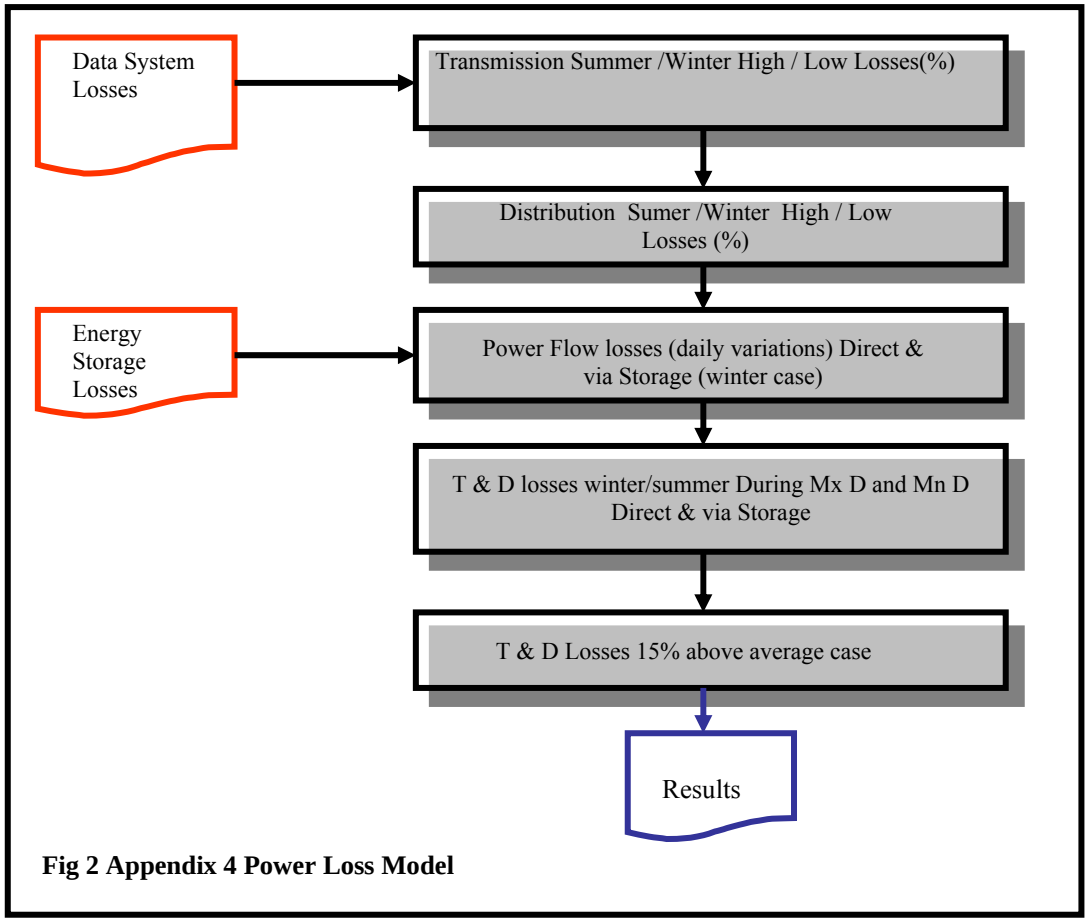


Fig 4.2 T & D Losses through direct and via embedded storage

The energy lost during the storage process was assumed to be 20% of the energy delivered to that store. The losses which occurred at different times during the day were computed as indicated in 5.

The variation of customer demand during the year was split into two periods (i.e. summer and winter) and typical loads for those periods used to measure the losses which occurred during the periods examined. It has been assumed that the best case for storage would be made when power was stored during the night time low demand periods and delivered back to the system during the period of the daily peak demand when losses supplying via the direct route to customers is the highest and prices are also expected to be at their highest

The calculation proceed through the following sequence

1) Determination of the losses during summer and winter time high demand andlow demand periods.
2) Power supply chain losses during the summer and winter for each parameter identified in Chapter 5.3.
3) The computation of the losses before delivery to the final customer along the the identified routes.
4) Results summarised in the succeeding tables.

The calculations are intended to give an indication only of the savings which may be obtained using local energy storage. A complete model of the entire transmission and distribution system would be required to deliver an accurate evaluation.

A 4.3 Spreadsheet Calculations

Transmission and Distribution Losses are found in

Appendix 4 sheet1

Optimum Energy Storage Locations are found in

Appendix 4 sheet 2

Appendix 5

The potential benefits from Embedded Energy Storage

A5.1 Introduction

The different operating patterns which may be carried out by an operational power station result in different operational efficiencies. In order to investigate the variation in both efficiency and emission levels which occur under these conditions, four distinctly different operational scenarios have been devised and the important parameters monitored.

Two separate models are used, one examines the technical performance of the power plant and the second considers the financial consequences of each scenario (described in Chapter 6). The two models are linked automatically.

A5.2 The technical & financial model

The constant operation of the power plant at optimum performance forms the base case against which the other operational modes are compared. The technical model is illustrated in Fig A5.1and the calculations follow the sequence shown in the flow diagram Fig A5.2

The input data is derived from the results of the analysis of the CCGT plant calculations obtained in Chapter 3.

The time periods were selected to represent periods when low, medium and high transmission and distribution losses are experienced on the supply networks. The transmission and distribution losses which have been used were selected to represent average conditions. There will be sectors of the networks where the actual losses will be higher than those used in these calculations.

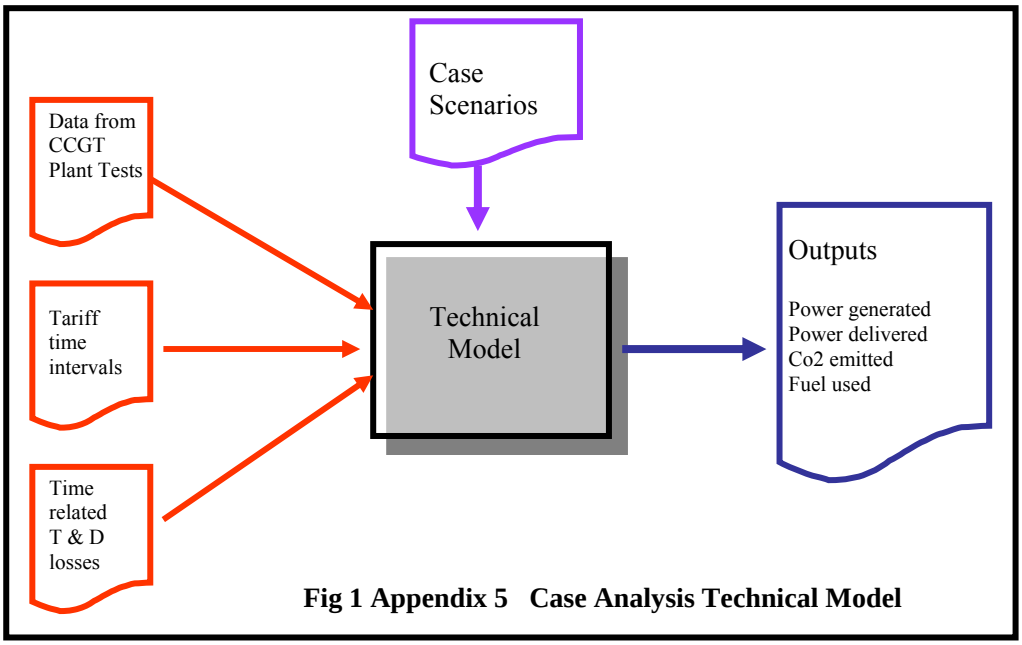


Fig A 5.1 The technical model Scenario analysis

The 'Turn Round' efficiency of the energy storage unit was nominated to be 80% although in practice this figure will depend upon the technology employed.

The plant availability (CCGT plant) was estimated to be 92%. The storage devices were assumed to have higher values of availability and therefore considered to be available to operate when the GGCT plant was producing power.

The power generated for each period was set by the operational pattern derived from the case profile of each scenario. The total power delivered to the customer was computed after the power loss during transmission and distribution had been deducted (Sheet 1 & Sheet 2). The results of the different modes of operating the power plant were contrasted with the plant operating under optimum conditions.

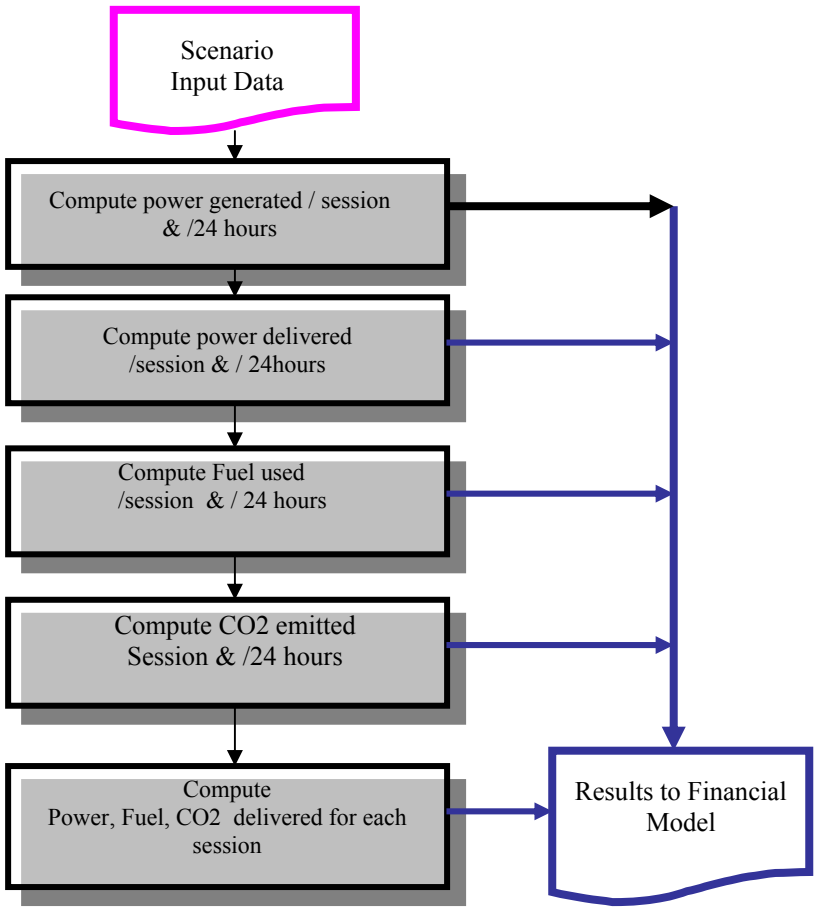


Fig 2 Appendix 5 Scenario Analysis

Fig A5.2 Computational flow diagram (Technical Model)

During each case evaluation, the CO_2 emitted per MWh delivered to the average customer was computed (Sheet 3). The potential cost of these emissions was calculated to demonstrate the impact of the Carbon Trading scheme should it subsequently be charged under the terms Phase 2 of this instrument from 2009 onwards.

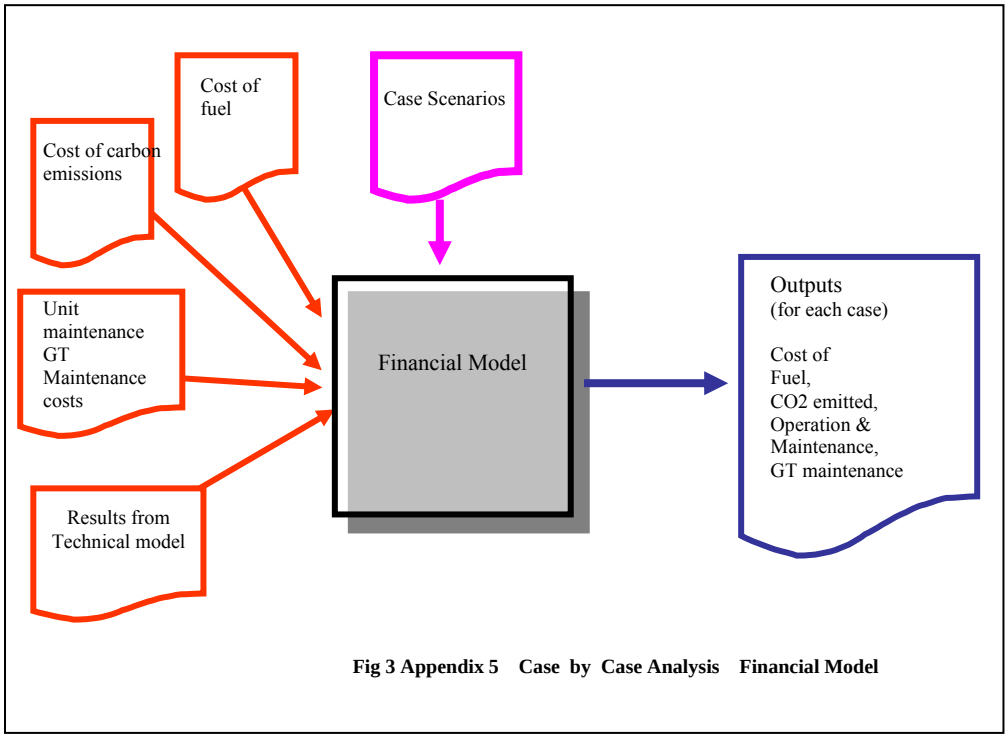


Fig 5.3 Model flow diagram for the Cost evaluation of each scenario

A5.3 Spreadsheet Calculations

The case by case analysis follows the routines shown in the spreadsheet Appendix 5.

Appendix 5 Sheet 1 A combined analysis of the Fuel used, Power produced, CO_2 emitted for each scenario.

Appendix 5 Sheet 2 The Income and Expenditure associated with each scenario

Appendix 5 Sheet 3 The CO_2 emissions under each scenario

Appendix A6

Technical and Economic Analysis of embedded Energy Stores

A6.0 Introduction

The integrated model (Fig A6.1) is designed to examine the technical characteristics of hydraulic fluid flow and gas pressure profiles of the proposed pneumatic – hydraulic energy store. It is used to establish the minimum capital cost of the unit for specific quantities of energy stored.

A range of gas pressures are considered (350 to 800bar) for a number of different storage capacities from 10kWh to 1000 kWh. (Spreadsheets 1 to 5)

The costs of the various components have been used to compile an estimated capital costs for installed energy stores of the ranges of size and gas pressures used for the technical mode. (Spreadsheet 6)

The 2nd phase of the model examines the cash flows produced by embedded energy storage projects under the current regulations and commercial tariffs. The industrial tariffs are examined in order to extract the maximum and minimum tariff differentials (Spreadsheet 9). The estimated capital costs and the cash flow data are used to evaluate the potential investment returns for a number of different company structures designed to cover maximum savings which an energy store may deliver, (spreadsheets 7, 8 and 10).

The architecture of the integrated model is shown in Fig A 6.2 and the sub-models are models is illustrated in diagrams A6.3 and A6.4.

A6.1 The Technical Model

The mathematical analysis is described in chapter 9 and the flow diagram A6.2 illustrates the model routine. The calculations are shown in Appendix 6 Sheet 1 to 4 and summarised in sheet 5.

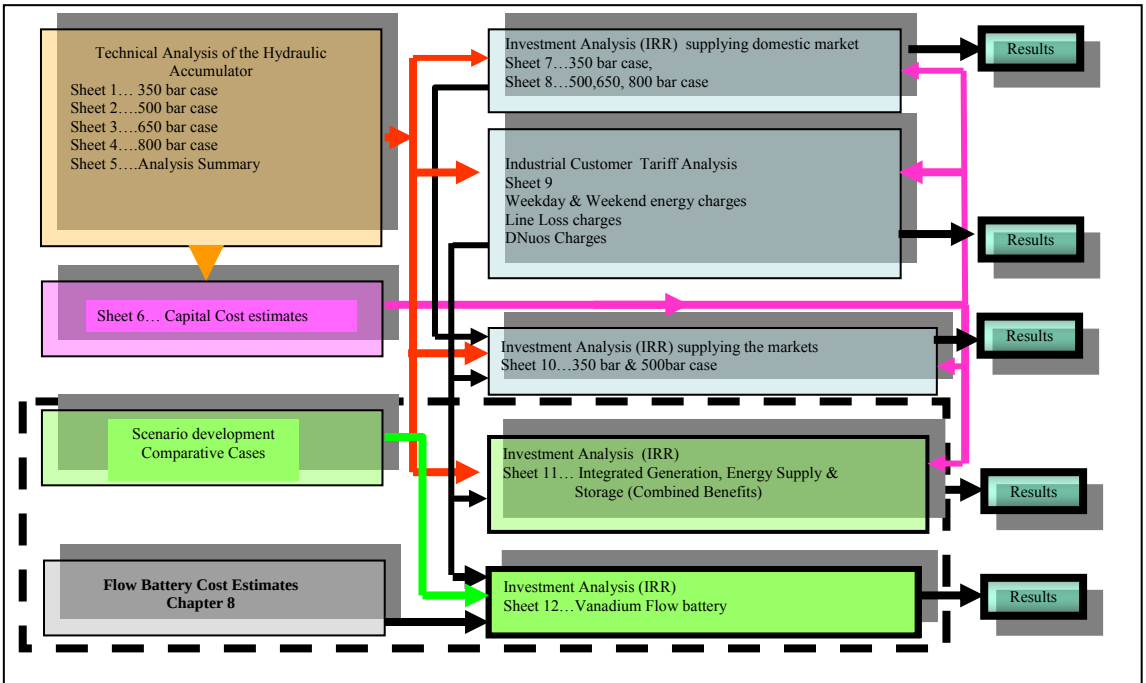


Fig A6.1 The Integrated Model

The results of the model analysis are passed to the capita cost model and an estimate of the costing for a range of gas pressures and energy storage capacities are computed to match the potential applications which could be embedded within the electricity distribution system at various voltage levels.

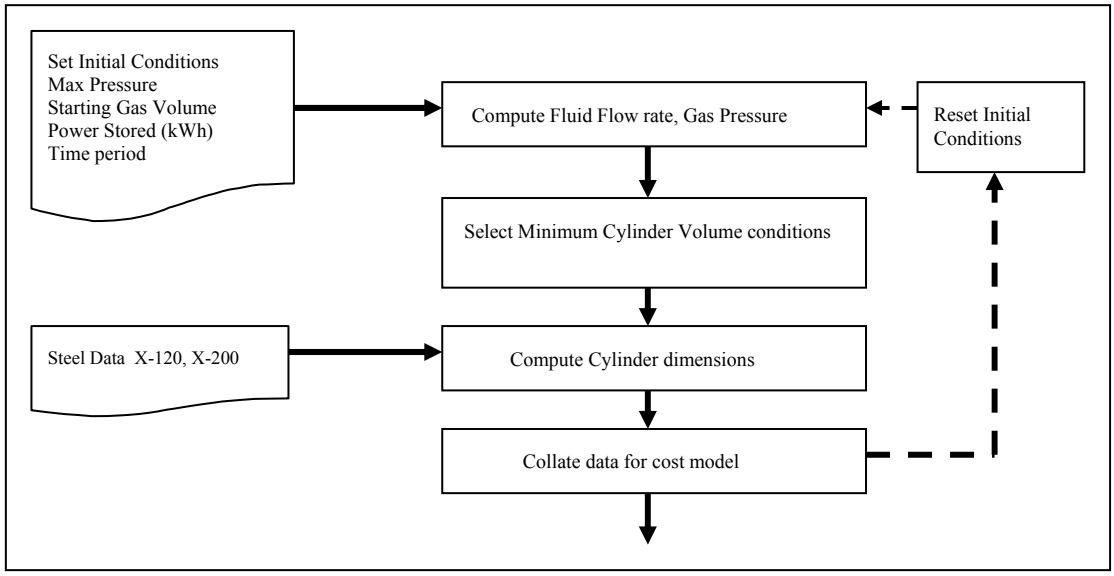


Fig A6.2 The pneumatic – hydraulic energy store flow diagram

A6.2 Capital Estimates

The capital costs, installation and commissioning costs have been compiled for the range of embedded energy storages by collecting together the component costs and estimates of the associated installation and commissioning costs.

The estimating routine is illustrated in the flow diagram A6.3. The calculations are found in Appendix 6 Sheet 6.

A6.3 The investment Model

Data from the previous calculations are used to develop the cash flows which are available from the different commercial structural arrangements.

Each structure is allocated the savings which would be available from the various cash flows that are in place around the electricity supply chain.

The domestic customer is able to take advantage of the differential night and day rates where as the industrial customer has a more complex routine where triad avoidance is an important contribution to the annual cash flow.

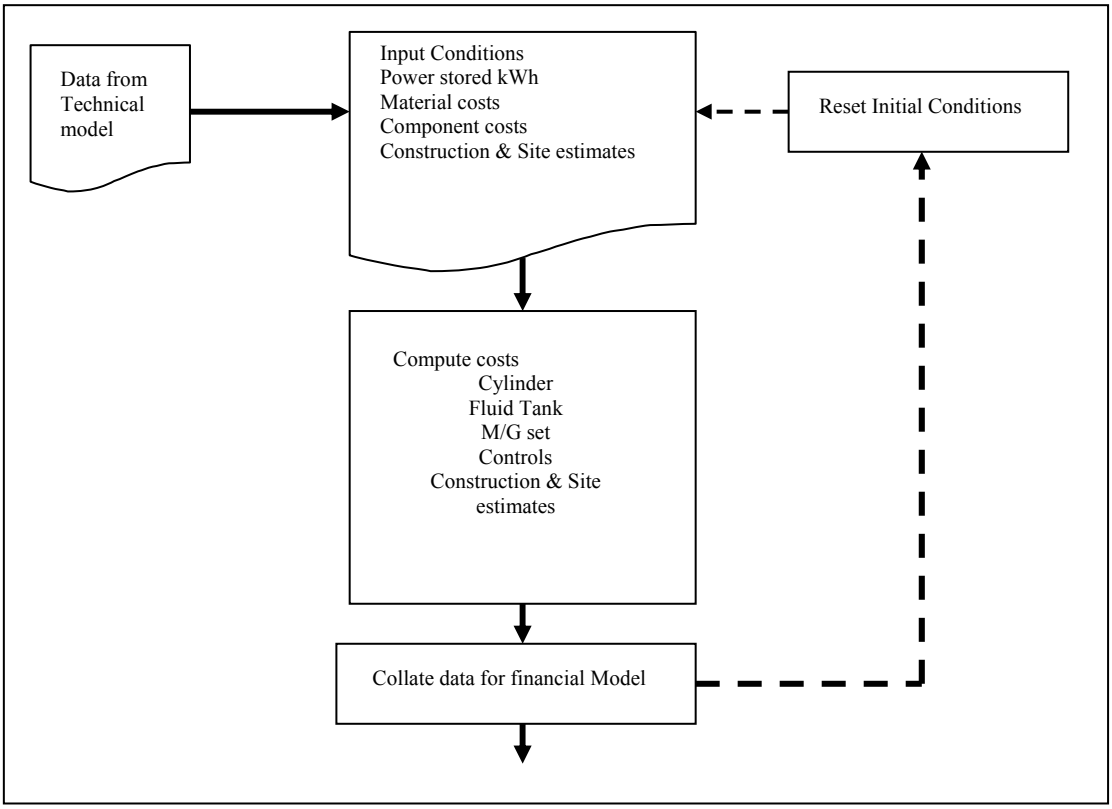


Fig A6.3 Capital costing routine

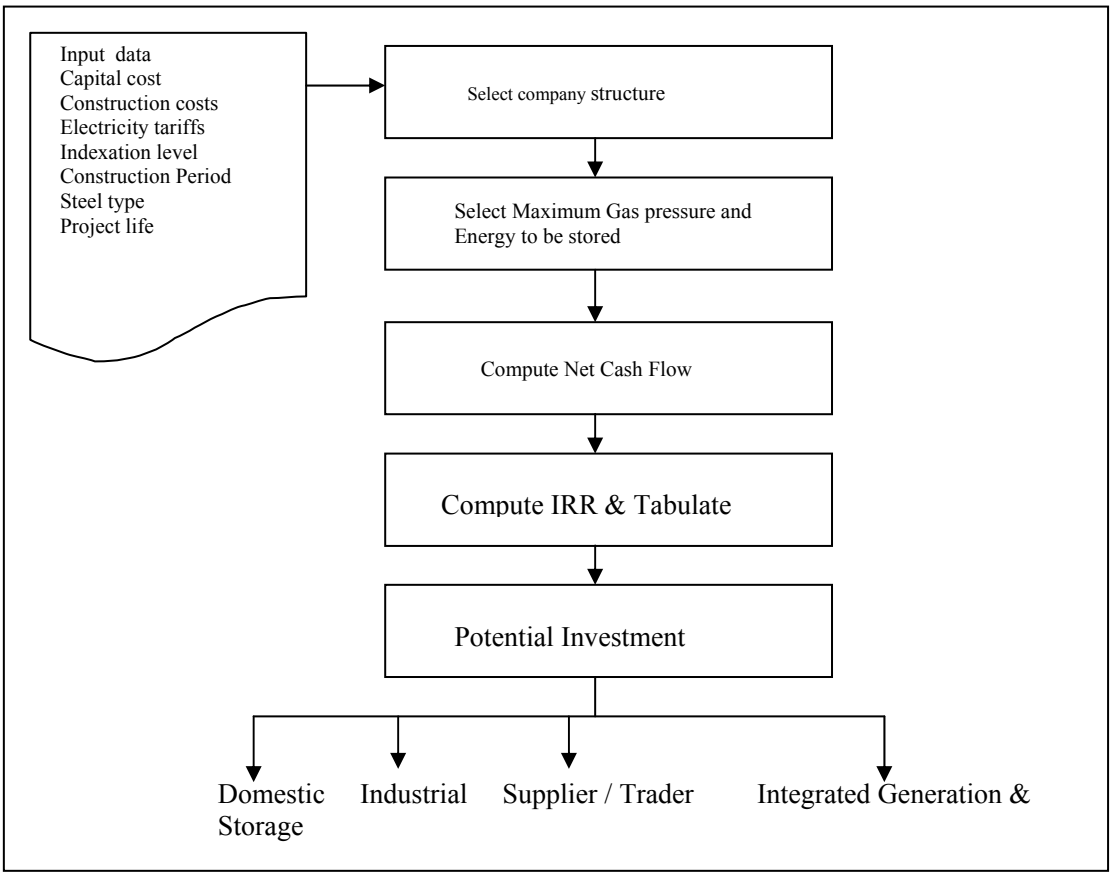


Fig A6.4 The Flow Diagram for the investment analysis.

The most complex situation is that of the integrated power generator and energy storage group where savings are realised from both the embedded energy store and from savings made during the generation operation.

The attached spreadsheet print is an example of the full contents of Sheets 1 to 13. The complete spreadsheet analysis is available on CD1 (Appendix 6).

A6.4 Investment analysis of the Vanadium Flow Battery

In the absence of specific cost data for any of the energy storage capacities envisaged for the Vanadium Flow Battery, it was decided test the financial sensitivity of the technology to a range of capital costs and to identify the maximum capital sum which could be expensed to achieve an IRR of 8%.

As the cost of capital depends upon the current bank rate, the project risk perceived by the holders of the senior debt and the return on equity required on the part of the owners, a series of graphs were produced, which illustrate the sensitivity of the investment return to variations in capital input, Fig A6.5.

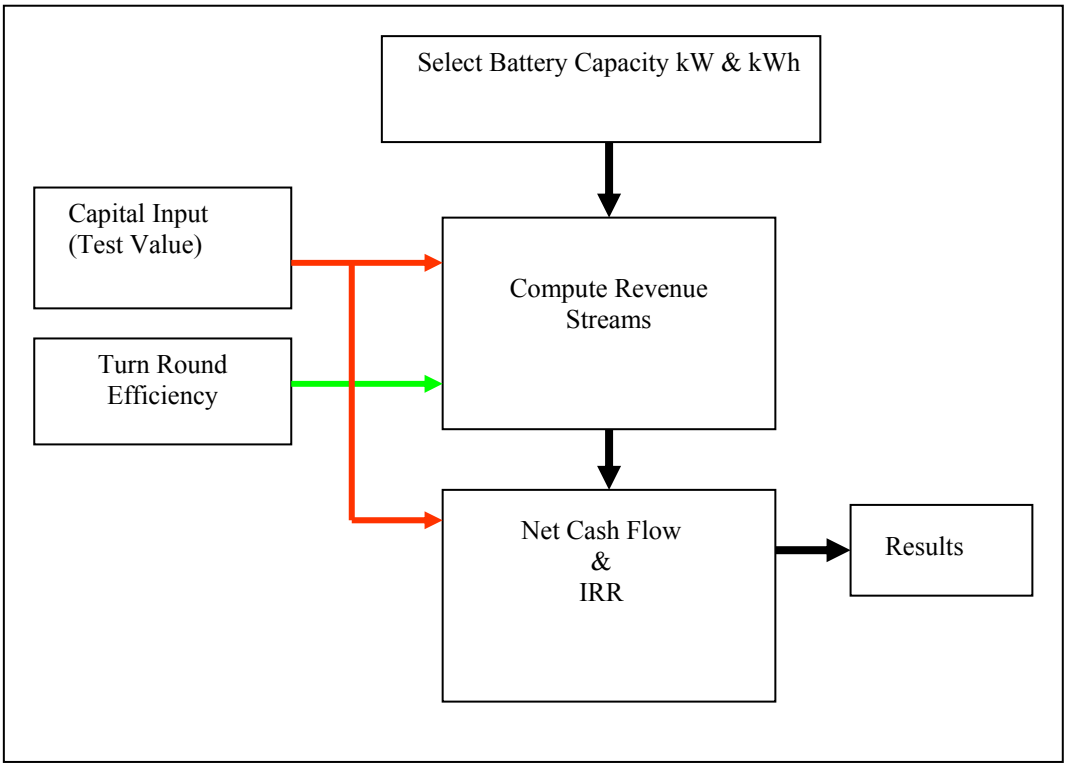


Fig A6.5 Vanadium Flow battery investment model

A6.5 Details of Spread Sheets

Pneumatic- Hydraulic Energy Store model

Sheet 1 350 bar model

Sheet 2 500 bar model

Sheet 3 650 bar model

Sheet 4 800 bar model

Sheet 5 Summary sheet

Capital Cost model

Sheet 6 Capital Cost estimates

Investment Evaluation model (Domestic Tariff)

Sheet 7 Investment Analysis 350 bar

Investment Evaluation model HP (Domestic Tariff)

Sheet 8 Investment Analysis 500 bar, 650 bar & 800 bar models

Industrial Tariff Analysis (Industrial Tariff)

Sheer 9 Calculation of Tariff price variations

Integrated Generation & Tariff benefits

Sheet 10 Scenario Analysis (Tariff benefits only)

Sheet 11 Scenario Analysis (Tariff plus Generation benefits)

Financial Analysis Vanadium Flow Battery

Sheet 12 Capital cost / IRR analysis (domestic & Industrial Tariffs)