Cogeneration "Ready Reckoner"

Software to assist with an initial evaluation of the viability of cogeneration

User's Manual

Version 3.1

September 2002

The Australian EcoGeneration Association

Commonwealth Department of Industry, Tourism & Resources

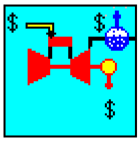
Sinclair Knight Merz Pty Ltd

Contents

1. Introduction

1.1 The Cogeneration "Ready Reckoner"

"Cogen_RR" is a program to assist users with a "first pass" technical and financial analysis of cogeneration at their site. The program is a 'Ready Reckoner' intended for quick preliminary evaluations. Refer to the Disclaimer section of this manual.



Cogen 'Ready Reckoner'

The Cogeneration Ready Reckoner is distributed by the Australian Commonwealth Department of Industry, Tourism and Resources in association with the Australian EcoGeneration Association (to become the Australian Business Council for Sustainable Energy).

The Ready Reckoner conducts a simple technical and financial analysis of a cogeneration opportunity. Should the cogeneration opportunity appear attractive on this evaluation, then it is recommended that the user conduct more detailed analyses, or engage suitable advisers, to consider the project evaluation to the extent necessary to commit funds or to entertain alternatives such as entering into Build-Own-Operate contract arrangements with other parties.

1.2 Information

The Cogeneration Ready Reckoner was developed as a cooperative exercise between the Department of Industry Science and Resources (the Department) and the Australian EcoGeneration Association.

The Department is acting on behalf of the Energy Management Taskforce (EMTF), which is composed of representatives from Commonwealth, State and Territory governments and New Zealand. EMTF's mission is to facilitate delivery of national energy management policy and program objectives assigned to the Australian and New Zealand Minerals and Energy Council (ANZMEC) - now the Ministerial Council on Energy, through coordinated action of all governments.

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Platform

This program was written using Borland™ C++ 5.0 The program was developed under Windows™ NT4 running on a Pentium™/500 with SVGA graphics.

The developer has attempted to use the device independence provided by the Windows™ environment however it may be the case that the program does not operate as designed on all platforms, or print successfully to all printers which the user may desire to use.

The developer and owner accepts no responsibility for failure of the program to run satisfactorily on any particular platform.

Borland, Windows etc are trademarks of their respective owners.

Copyright

1.3 Disclaimer

The user acknowledges that the Commonwealth of Australia, Australian EcoGeneration Association and Sinclair Knight Merz Pty Ltd (together "the Providers") provide the Cogeneration Ready Reckoner software on the following basis.

- That the Program is not intended to be a final or authoritative assessment but rather a preliminary assessment of potential cogeneration opportunities.
- That the software is not intended to be a tool for basing final investment decisions upon, and in all cases the user must conduct sufficient additional analyses and obtain appropriate professional advice before proceeding with any investment decision.

- That the Providers do not and cannot in any way supervise, edit or control the content of any information or data accessed through the service and shall not be held responsible in any way for any content or information accessed or input in this service.
- That the Providers do not warrant that printed or displayed outputs from the program are accurate assessments of the viability of any particular course of action.
- That the Providers are released from and indemnified, along with its servants and agents against all actions, claims and demands which may be instituted against the Providers arising out of use of this program or of any other person for whose acts or omissions the user is vicariously liable.
- That the Providers do not warrant that the software is free from ‘bugs’ or defects.

2. Installing the Cogeneration 'Ready Reckoner'

The Cogeneration 'Ready Reckoner' is shipped with an Installshield™ installation routine that should install and register the program appropriately on most computers.

The program uses Dynamic Link Libraries (DLL's) provided by the compiler manufacturer (Borland) for use by the program.

Because other programs may be in use on the computer that use the same DLL's, it is strongly recommended that the user exit all other programs prior to attempting to install the program.

3. Methodology

3.1 Basics

This section discusses the algorithms used and options available in the program.

Benchmark case, Cogeneration case and the Difference case between the two
The analysis can be considered in the following parts:

- A benchmark case, defining the steam and electricity etc parameters that would apply at the site in the event that cogeneration is not installed. This might include steam (or hot water) and electricity usage load growth, operations and maintenance costs, capital costs and various tariffs etc paid for the fuel and electricity etc used.
- A cogen case, defining a cogeneration configuration, including selection of a unit (a particular gas turbine, recip engine or parameters for a steam turbine topping cycle), a fuel (which might be different than the benchmark fuel), operations and maintenance costs, tariffs and the like.

Note that whether the cogeneration opportunity is attractive or not, is determined by whether or not the difference between the cash flows of the cogeneration case and the benchmark case, including consideration of capital costs and appropriately discounted (i.e. a net present value (NPV) analysis) is greater than zero at the discount rate applied.

Results are therefore primarily calculated for the difference case and the "bottom line" parameters (NPV and internal rate of return (IRR)) are calculated on the differential cash flows.

Operating periods (Peak, offpeak etc)
Additionally, each year can be divided into (up to) twelve periods. These periods might be (for example corresponding to some electricity tariff period or plant operational period): Peak, Offpeak and Shoulder. Using these periods, the user may define different thermal and/or electrical loads in each period, and/or different tariffs applying to electricity bought and sold in these periods. Because the user may decide (based on the program output) that for some of these periods the marginal cost of generation is greater than the marginal value of the power produced, that the cogeneration unit should be shut down in some periods. This facility is provided. Refer to Section 8.5.

Dividing the cogeneration case into 'N' and 'N-1' periods
Conceptually, the cogeneration case is divided into two sets of operating hours per year - the times when 'N' units are running (where N is the number of cogeneration units installed) and the times when N-1 units are running (because 1 unit is down for maintenance or some other reason). That is, this analysis considers cogeneration unit availability for single failure events. This is assumed justified for the modern high availability units, assuming that the user does not schedule more than one unit down for maintenance at a time, and considering the preliminary nature of the calculations provided by the program.

For example, if the site process operates 24 hours/day x 365 days per year = 8760h/year, and there is one cogen unit with an availability of say 95% installed, then the cogeneration year would be broken down and analysed as:

- 8760 x 95% = 8322h/year with the cogen unit running
- 8760 x 5% = 438h/year with no cogen unit running in which case the flows are taken to assume auxiliary fired boilers are operating and electricity is imported from the grid in the same manner as for the benchmark case.

On the other hand, if two cogen units the same as above (95% unit availability) were installed, the cogeneration year could be broken up into:

- 8760 x 90% = 7884h/year with 2 cogen units running
- 8760 x 10% (i.e. 2 x 5%)= 876h/year with one cogen unit running in which case the flows are calculated for this capacity.

Timing of cash flows

Cashflow values are timed to be grouped on the middle day of the Year. Tax is timed to be payable one year in arrears.

Year 0 is taken to be the capital cost year, all initial capital cost elements are bought to the middle day of Year 0 using Interest During Construction (IDC).

The project is taken to commence commercial operation on the first day of Year 1. All annual cashflows are averaged for the Year onto the middle day of each operating year. The project operates until the last day of the nominated number of operating years.

On the last day the project is scrapped and the residual written down value is written off for tax and income is received for the assigned residual capital value (sale price).

The Tax treatment of the write-off, sale income and the last commercial year of operation are accounted for in the final spreadsheet year, one year after the last year of commercial operation.

Debt repayments and interest

Debt repayments are modelled as **monthly** repayments of equal size to repay the loan over its term.

Analysis method

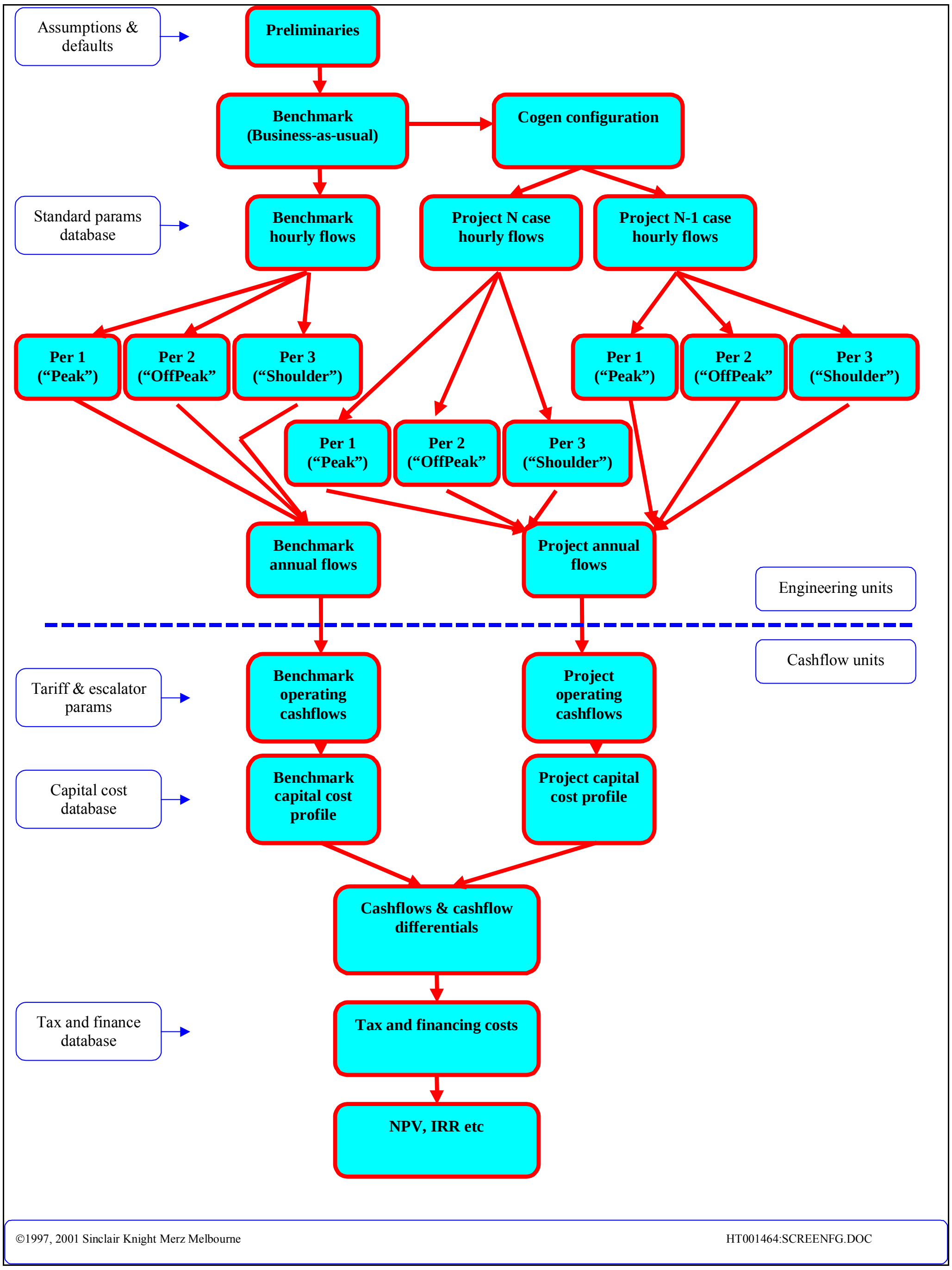
Refer to the attached flow sheets for the analysis ‘algorithm’.

The object is to obtain financial parameters representing the viability of the project (NPV, IRR etc). These are derived from cash flows, which in turn are derived from annual flows (in engineering units such as TJ of fuel) and a tariff, such as $/GJ.

Annual flows are derived from hourly flows and the number of hours in the sub-period.

Tariffs are derived from an initial tariff and an escalator to convert the tariff to the time (year) that the calculation is seeking.

■ **Figure 1 Analysis flow diagram**



For the engineering unit flows (e.g. hourly and annual electricity and gas flows etc), the analysis essentially solves the following simple heat and mass balances, assigns tariffs to each flow element and calculates annual cash flows accordingly.

Note that unless the steam quantity changes (such as if absorption chillers are used, or if a gas turbine plus steam turbine configuration is used), water treatment requirement is assumed unchanged between cogen case and the benchmark. This is generally a good assumption for simple gas turbine and recip cogen but the user should be aware that topping cycle cogen may require a higher level of water quality due to higher boiler operating conditions in the cogen case vs. benchmark case.

Degradation

It is important to recognise that performance parameters are usually quoted for clean-as-new equipment. Some equipment, and especially gas turbines, suffer performance degradation in the operating period between major overhauls. This is generally due to:

- Compressor fouling (some of which is partially recoverable with washing)
- Hot section (combustors and expansion turbine) degradation due to exposure to the hot corrosive gases

For the purposes of this analysis the following average degradation allowances are provided:

- Gas turbine based:
  - ◊ Power output degradation: 3%
  - ◊ Heat rate degradation 2%
- Reciprocating engines nil
- Topping cycles nil

Cogeneration efficiency

The program indicates some efficiency parameters for the benchmark and cogen configurations.

It is important to note that there is no universal standard for quoting the efficiencies and related parameters for cogeneration plant.

When comparing the efficiencies of cogeneration plants with the Benchmark case (no cogen), it is important to consider that the benchmark comprises both efficiencies and losses of both a site based thermal heat raising facility (steam or hot water), and also imported electricity (which might be generated say with coal and then transported to the site via a transmission system).

In calculating annual average efficiencies and emissions, the averages include the times during the year when N-1 units are operating, and allows for imported electricity (and the emissions created from the production of this electricity) in the calculations.

The following measures are applied:

<u>Net electrical efficiency</u>

$$\frac{\text{[Cogen gross elec output] + [imported electricity] - [parasitic electricity]}}{\text{[Fuel to cogen unit] + [fuel used for imported electricity]}}$$

<u>Electrical efficiency (fuel chargeable to power basis)</u>

$$\frac{\text{[Cogen gross elec output] + [imported electricity] - [parasitic electricity]}}{\text{[Fuel to cogen unit] + [fuel used for imported electricity] - [fuel for steam]}}$$

where [fuel for steam] is the fuel which would have been used to raise the site steam (or hot water) at the auxiliary boiler efficiency

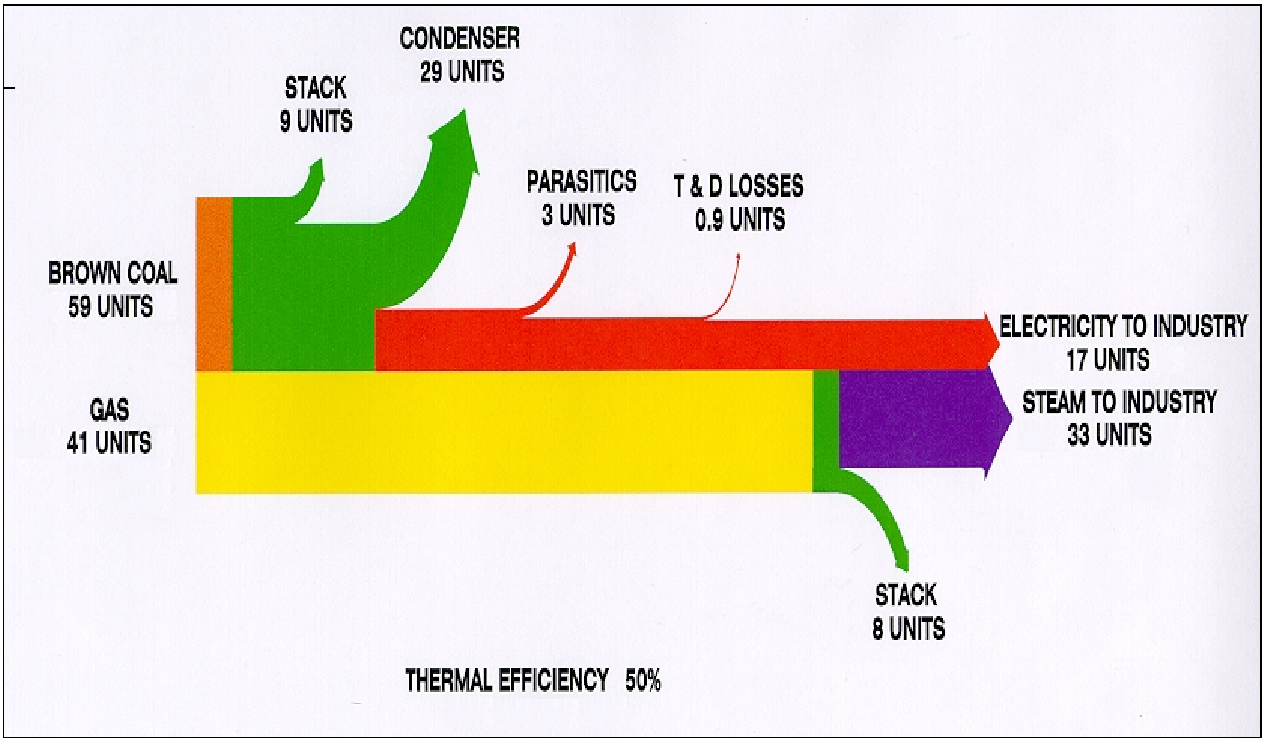
Overall thermal efficiency

[Cogen gross elec output] + [imported elec] - [parasitic electricity] + [Site steam]
[Fuel to cogen unit] + [fuel used for imported electricity]

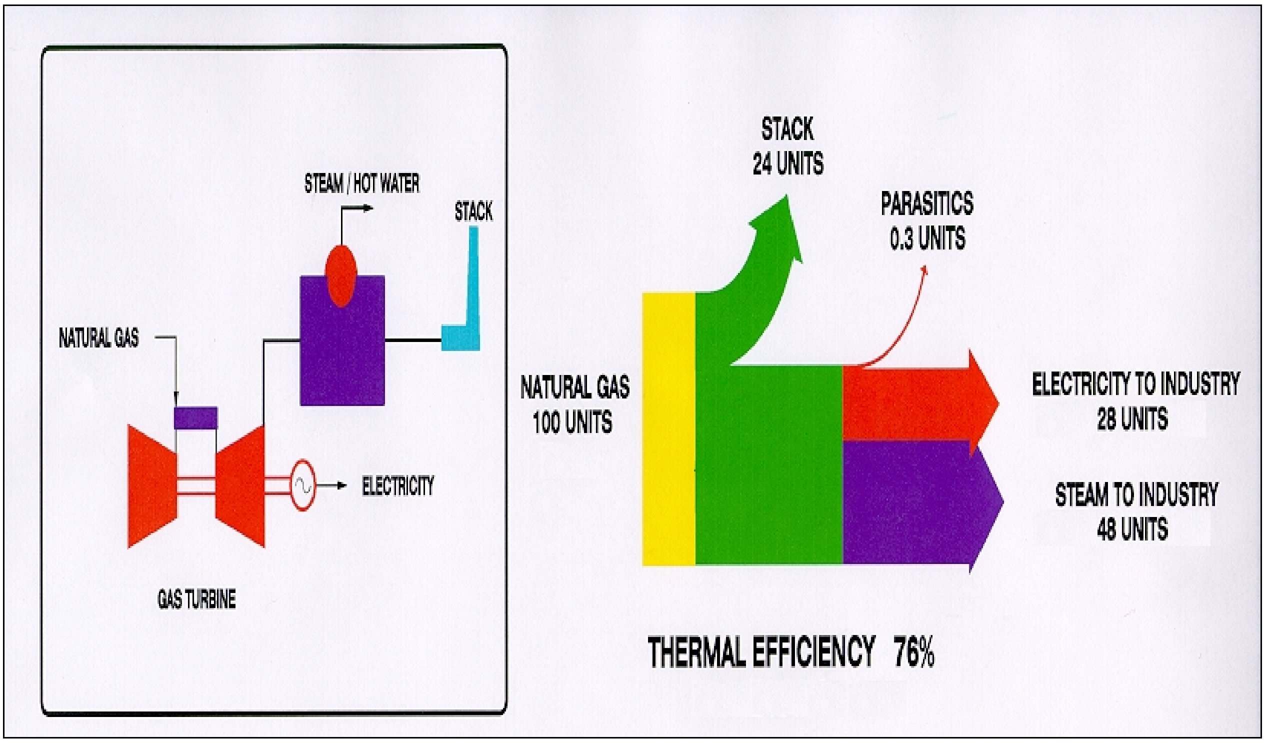
where [site steam] includes hot water as applicable

Typical Sankey diagrams with representative values for energy flows are provided as shown in Figure 2 to Figure 6:

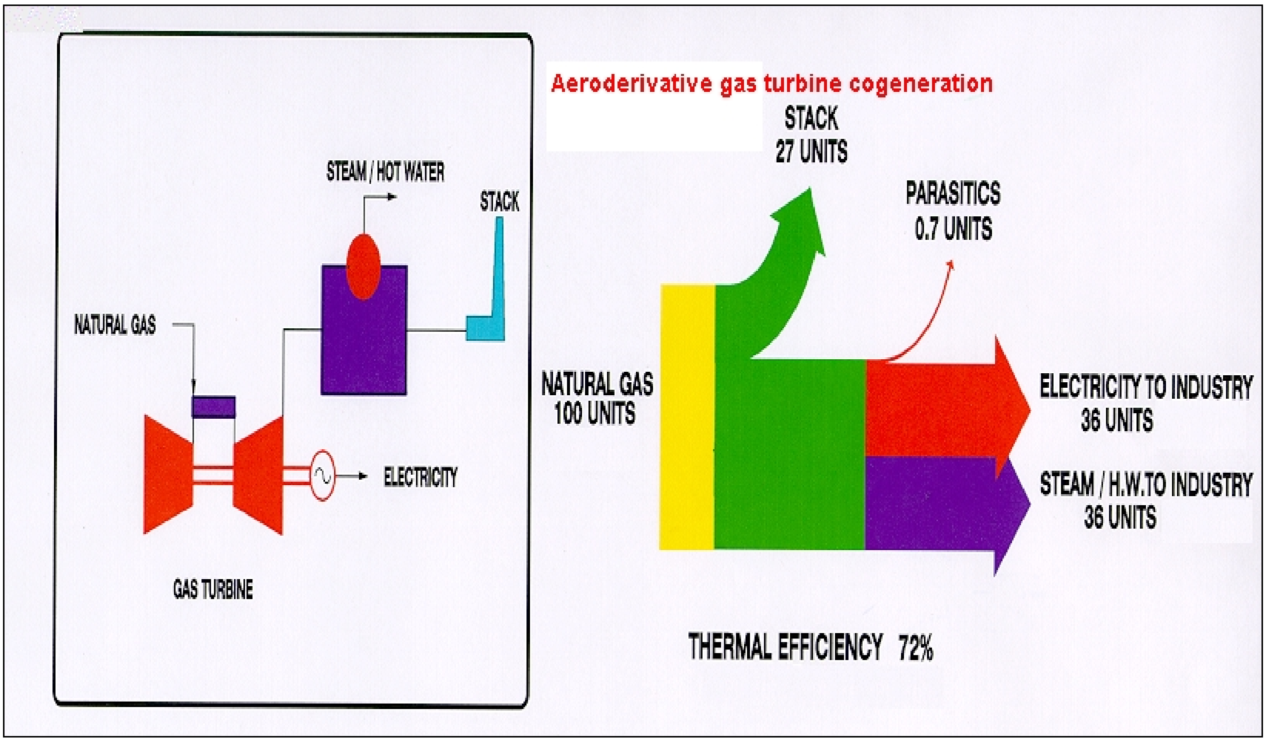
- **Figure 2 Sankey diagram: Benchmark electricity and steam provision**



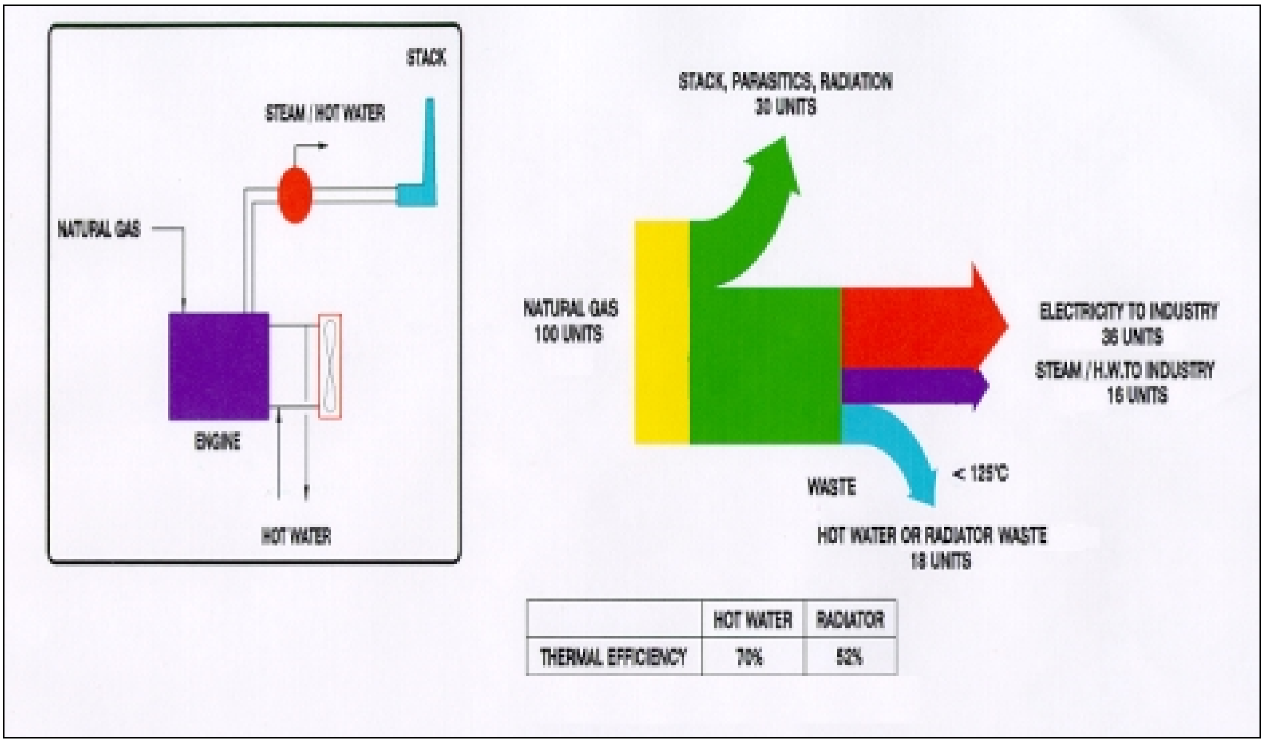
- **Figure 3 Sankey diagram: Industrial gas turbine cogeneration**



- **Figure 4 Sankey diagram: Aeroderivative gas turbine cogeneration**

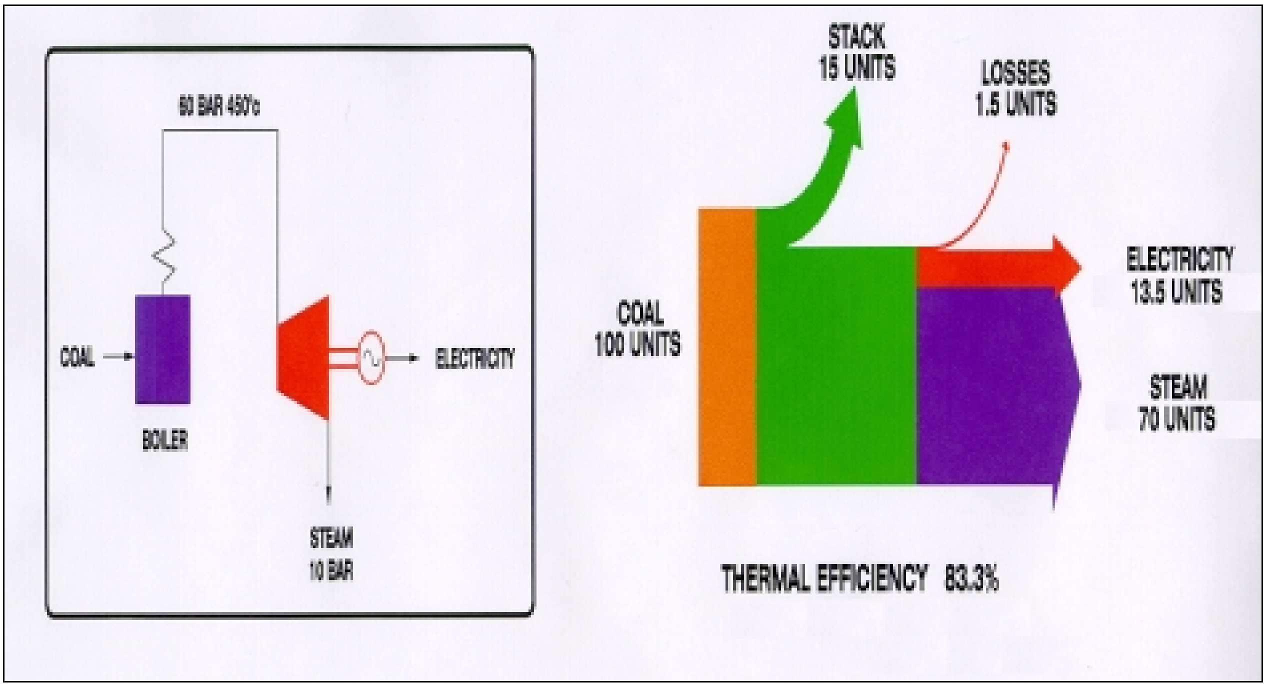


■ **Figure 5 Sankey diagram: reciprocating engine cogeneration**



	HOT WATER	RADIATOR
THERMAL EFFICIENCY	70%	52%

■ **Figure 6 Sankey diagram: Topping cycle cogeneration**



These diagrams indicate that different types of configurations inherently have different natural quantities of steam and electricity provided. Depending on the site steam and electricity loads, and upon the relative values of fuel, electricity and capital, these may indicate the natural configuration for first review.

Heating values, and net vs gross power

It is customary in Australia and the USA to quote efficiencies for power plants on a Higher Heating Basis (HHV) as opposed to a Lower Heating Value basis. Boiler efficiencies are also normally quoted on an HHV basis. Heating values at constant pressure or constant volume are also slightly different. Constant pressure heating values are assumed in the program

Fuel is normally sold on a HHV basis.

Gas turbines in particular, and usually reciprocating engines, are usually quoted on a Lower Heating Value basis, or LHV.

The difference between the two bases is significant. For reference the HHV (also known as Higher Calorific Value (HCV), Gross Calorific Value (GCV) etc) of a fuel is the amount of heat released if a fuel is combusted at nominally standard atmospheric conditions and the products of combustion are returned to this pressure and temperature assuming the water content of the exhaust constituents is in liquid form.

The LHV calculates the heat release assuming the exhaust water content is in vapour form.

For natural gas the difference between the two is that HHV ≈ LHV + 11%. This difference flows through to efficiency calculations and the calculations of fuel costs. For coal, oil etc the difference is less but still significant.

The program attempts to be specific about which value is required or displayed, but for reference:

- Heat rates of gas turbines and recip engines LHV
- Boiler efficiencies HHV
- Overall efficiencies HHV
- Fuel tariffs HHV

The user should also be aware whether the performances considered are on a gross or net basis. The gross basis is calculated on the power output as measured at the generator terminals. The net output is calculated after deduction of the power consumed by auxiliaries and losses in transformers etc (which together are the "parasitics"). Efficiencies and emissions can also be quoted on a gross or net basis. The user should be aware of this difference.

Additionally, when performances are provided informally by a manufacturer or in the literature, the quoted performances are generally the "expected" performances and would not be guaranteed by the supplier at this level. Normally the manufacturer applies a margin (e.g. 3%) to the expected performance parameters to come to the guaranteed parameters. Use of "guaranteed" performances in an analysis would create a more conservative assessment. No special allowances are made by the program and hence the outputs would normally represent the "expected" case.

Nomenclature (refer also to the Glossary section):

- Data input and output are in S.I. units (DegC, kPag) for Australia and in imperial units (DegF, psia) for the USA
- GT - gas turbine
- ST - steam turbine
- Recip - reciprocating engine
- D/A - deaerator
- WHB - waste heat boiler
- Cogen - cogeneration
- HHV - higher heating value
- LHV - lower heating value
- T&D - transmission & distribution
- O&M - operation & maintenance
- AUD - Australian dollars, USD are used for USA
- ASL - above sea level - refers to site elevation in metres (feet)
- IDC - interest during construction
- FOB - free on board, i.e. normally quoted ex the factory excluding shipping and installation.

4. Using the Cogeneration 'Ready Reckoner'

4.1 Basics

This section provides recommendations as to the general sequence of events normally constituting a run through the program. The program methodology follows the logic shown in Figure 1.

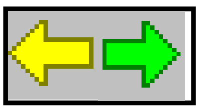
The user needs to enter a range of data into the program to describe:
- The site and site parameters, the type of cogen configuration
- The Benchmark Case hourly thermal (steam or hot water) and electricity flows and load growth for each Period (Peak, offpeak etc)
- Chilled water flows if applicable
- The Benchmark Case fuel and the assumed nature of the imported electricity (for efficiency and CO_2 calculations)
- Whether in the Benchmark Case there are any capital costs that might be offset by the provision of a cogen plant (e.g. if a new boiler is required that might not be necessary if a cogen plant was built)
- The cogen unit selected
- The Cogen Case unit fuel parameters
- The Cogen Case capital cost assumptions
- Financial parameters including tariffs (for each Period: Peak, Offpeak etc), escalators (to convert tariffs to future values or to account for relative changes in costs over time and the financial assumptions for the analysis (discount rate, debt and tax assumptions etc).

The program may then calculate:
- Hourly and annual flows in each case
- Annual cash flows in each case
- Annual cash flow for the differential case (Cogen cash flows - benchmark cash flows)
- Financial summary parameters such as NPV, IRR etc
- Sensitivity graphs for the variation in import electricity cost, export electricity value, cogen case fuel cost, capital cost and discount rate.

The program contains a Tools section (see Section 10) for adjustment by the user of default values and for maintaining the gas turbine and recip engines database.

Recommended order of calculation

The recommended manner of calculation is easily followed by using the "Next" and "Previous" buttons on the toolbar:



By following the Clicking the Next arrow, completing the requested data, and clicking the Next arrow again etc, the program will step through the data in the recommended order and finally display the differential case cashflows.

4.2 Menu commands

The user may alternatively select any step from the menu at the top of the screen. Note that selection of a non-zero site thermal load is critical to the calculation process (unless a combined cycle plant is being considered) and many steps and menu selections are disabled until a satisfactory thermal load is entered by the user. The available selections are as follows:

Menu	Menu item		Sub-menu item	Description
File	New			Creates a new analysis
	Open			Opens an existing analysis file
	Close			Close this document
	Save			Saves this analysis
	Save As			Saves this analysis with a new name
	Print			Print this analysis
	Printer setup			Setup this analysis print characteristics
	Print preview			Display image of print output
				A recent file list of the last 4 files opened
	Exit			Quits Ready Reckoner and prompts to save the analysis data
General	Admin/configuration			Select run title, analysis years & cogen config type
	Operating hours			Edit operating hours parameters for process & cogen
	Technical parameters			Edit steam conds, site conditions, water parameters and number of cogen units
	Chilled water			Parameters relevant if chilled water is selected as one of the potential thermal outputs in the Admin/configuration dialog box
	Previous			Go to previous step in analysis
	Next			Go to next step in analysis
Benchmark	Flows and load growth			Edit benchmark first year flows and load growth
	Imported electricity			Edit imported electricity assumptions
	Select fuel			Select benchmark fuel from standard list
	Adjust fuel			Change fuel properties
	Deaerator data			Edit deaerator conditions
	Boiler			Edit fired boiler parameters
	Capital cost			Edit capital cost for benchmark case
Cogen	Select unit			Select cogen unit from list in file
	Unit parameters			Edit parameters for cogen unit
	Select fuel			Select cogen fuel from standard list
	Adjust fuel			Adjust fuel properties for cogen case
	Capital cost			Edit capital cost parameters for cogen case

Menu	Menu item		Sub-menu item	Description
Financial	Parameters			Edit financial parameters for analysis
	Tariffs			Edit tariffs for financial analysis
	Escalators			Edit escalators for tariffs
Calculate	Benchmark		Hourly flows	Show the benchmark case hourly flows
			Annual flows	Show the benchmark case annual flows
			Cashflow	Show the benchmark case annual cashflows
	Cogen		N case hourly flows	Show cogen case hourly flows for time when all units up
			N-1 case hourly flow	Show cogen hourly flows for hours when one cogen unit down
			Annual flows	Show cogen case annual flows
			Cashflow	Show cogen case cashflows
	Differential cashflow			Show the cashflow difference (cogen - benchmark)
	NPV, IRR			Show the NPV and IRR of the differential cashflows
	Incremental operation			Gives short run incremental cost of operation vs not operating cogen
Sensitivity	Electricity import			Show sensitivity to changes in cost of electricity import
	Electricity export			Show sensitivity to electricity export value
	Fuel			Show sensitivity to cogen case fuel price
	Capital cost			Show sensitivity to cogen case capital cost
	Discount			Show sensitivity to discount rate
Tools	Change to Australia			Change default values and units to those appropriate for Australia. The US flag is shown to indicate the current country.
	Change to U.S.A.			Change default values and units to those appropriate for U.S.A. The Australian flag is shown to indicate the current country.
	Defaults			Edit defaults used in program
	Gas turbines			Edit file of gas turbine parameters
	Recips			Edit file of recip engine parameters
	Output results to CSV file			Creates a comma separated ASCII text file, with the outputs of the program. This may be read into a spreadsheet program for further analysis
Help	Contents			Access online help
	Using help			Help on using online Help
	About…			About the cogen_rr application

4.3 Toolbar commands

Tool bar support is provided for:

Create a new file
Open an existing file
Save a data file
Stop the analysis and exit the program
Print
Print preview
Go back to the previous command
Go forward to the next command
Location currently USA. Change to Australia
Location currently Australia. Change to USA
Go to the Help system

4.4 Configurations

The program can analyse the following configurations:

Cogen configuration	Site thermal load is steam	Site thermal load is Hot Water
Gas turbine with single pressure waste heat boiler	Yes	Yes
Gas turbine + steam turbine. Steam turbine can be back pressure or condensing type	Yes	No
Recip engine with single pressure waste heat boiler	Yes	Yes
Recip engine with single pressure waste heat boiler, and jacket water heat recovery	Yes but jacket water heat is not used	Yes
Topping cycle with back-pressure steam turbine	Yes	No

Some of the thermal or electrical load in the benchmark case might be to generate chilled water. If it is desired to review the potential to switch chilled water load from electric chillers to absorption chillers, then this facility is provided by the program. ‘Check’ the ‘Include chilled water?’ box in the Administration and configuration dialog box and this will enable the chilled water parameters menu item within the General menu.

Gas turbine / recip engine cogeneration configurations use gas turbines / reciprocating engines to generate electricity, and utilize the exhaust gas to generate steam in a waste heat boiler.

Topping cycle cogeneration configurations use high pressure steam generated in a fired boiler to generate electricity in a back pressure steam turbine. Steam is discharged from the steam turbine at a low pressure compatible with site process requirements.

Reciprocating engines perform better in cogeneration when a lower grade of heat is required (i.e.. hot water) than similarly sized gas turbine plant. Refer to the Sankey diagrams in the Basics section of the users’ manual.

Generally, reciprocating engines perform better (economically) generating low-grade (low pressure/temperature) steam than gas turbines of < $3MW_e$ unit size.

4.5 Default values and gas turbine/reciprocating engine units

The program comes with default values for various parameters.

These are typical values that might be found for a cogeneration plant in Australia or the USA.

Databases are also provided with indicative values for representative gas turbines (up to the largest available sizes) and reciprocating engines (generally less than 10MW size) that might be utilized.

The user may find that he/she may wish to change some of the default values to those applying for the particular location or type of plant under consideration so that each new run starts with the same assumptions. This can be done within the Tools menu (see Section 10).

The defaults and cogen unit databases are stored in files which are located in the same directory as the program. The program should find these automatically. If not (and the drop down list in the select unit dialog box is empty), copy the relevant files into the directory you are working in.

The files are:

- Gasturb.fil — Gas turbine parameters file
- Recip.fil — Reciprocating engines parameters file
- Defaults.dat — Default data such as tariffs etc

The user should maintain the gas turbine and recip engine files. Units can be added, deleted or edited using the Tools menu section. If these files are deleted or corrupted the user will need to re-create them using the Tools section.

Updated parameters should be available from the gas turbine and reciprocating engine vendors.

On the other hand if the Defaults.dat file is deleted or moved to the wrong location where the program cannot find it, the program will re-create this file using the values originally provided when the program was written.

Note there is no hard limit on the size of the gas turbine and recip units used. Whilst the program was written with a size range of up to 10MWe envisaged, the user can enter larger units although additional care with interpreting the outputs is advised.

5. Changing country – changed units, currency and default values

The program can display units of measure and currencies as are commonly applied in either:

- Australia, or
- U.S.A.

The country appropriate for the analysis is selected via either the buttons towards the right-hand-side of the tool-bar or using the Tools menu.

The country that has been selected is indicated by the flag on the tool-bar being displayed. To change to the alternative country simply 'click' the button that is displayed and the alternative button/flag that is 'greyed' will become displayed.

The units applied depend on the country selected, for example:

Item	Australia (Metric)	U.S.A. (Imperial)
Pressure	kPag	psia
Temperature	Degrees C	Degrees F
Length/Distance	meters	feet
Mass	kg	pounds
Steam flow	Tonnes per hour	Pounds per hour
Fuel heating values	MJ/kg	MMBTU/lb
Heat rate	kJ/kWh	BTU/kWh
Mass flow	Tonnes/hr	Pounds/hour
Fuel usage	GJ/hour	MMBTU/hour
Chilled water requirement	kWr	Tons
Monetary values	$Aus	$US

Depending on the country selected, different default values for various parameters will also apply.

6. File handling

The program uses standard Windows file handling and saving systems to allow the user to save the analysis for later re-use.

Files should preferably be saved with a ".COG" file extension for quickest identification of the relevant files by the program.

7. Printing

The program has facilities for printing, print preview and printer set-up. These follow the normal Windows™ style.

Note that the printing font is fixed at a small size font to maximize the number of columns fitted on each page.

If the number of years in the analysis is greater than approximately 15, it is recommended that the page orientation be changed to Landscape (using "Printer set-up" for example).

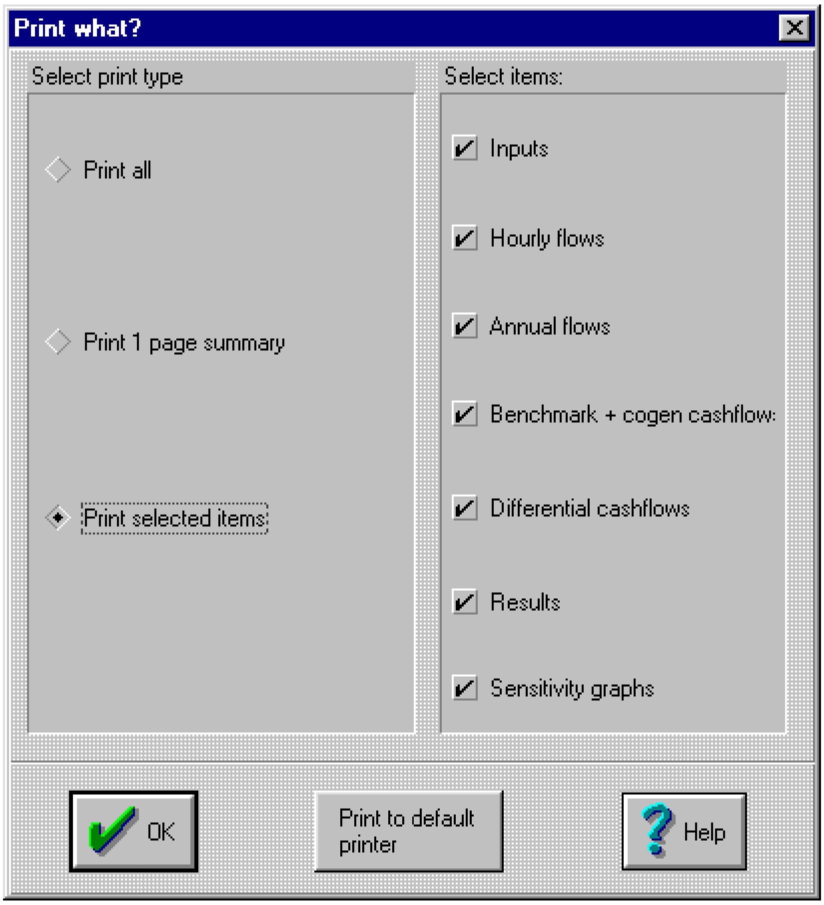
The "Print what" dialog box appears prior to printing or print-previewing of the outputs.

The "Print all" selection will print all the inputs and outputs (about 10 pages).

The "Print 1" page summary selection will print selected key inputs and outputs so as to fit onto a single page.

The "Print selected items selection" allows the user to select what is printed from the selections on the right hand side of the dialog.

The "Print to default printer" button will print without bringing the printer selection standard Windows™ dialog.



8. Dialog boxes

8.1 General

Dialog boxes are the Windows™ elements for the user to enter data into the program. Each dialog box requests the user to enter data about a particular technical or financial aspect of cogeneration analysis. The user can select the changes by clicking ‘OK’ or cancel the changes by clicking ‘Cancel’.

Each dialog box is also fitted with a ‘Help’ button. The user can click on this button and be shown a relevant page of the on-line help system for the dialog information requested.

A list of the dialog boxes is as follows, these are each described in detail below.

8.2 Administration / configuration dialog

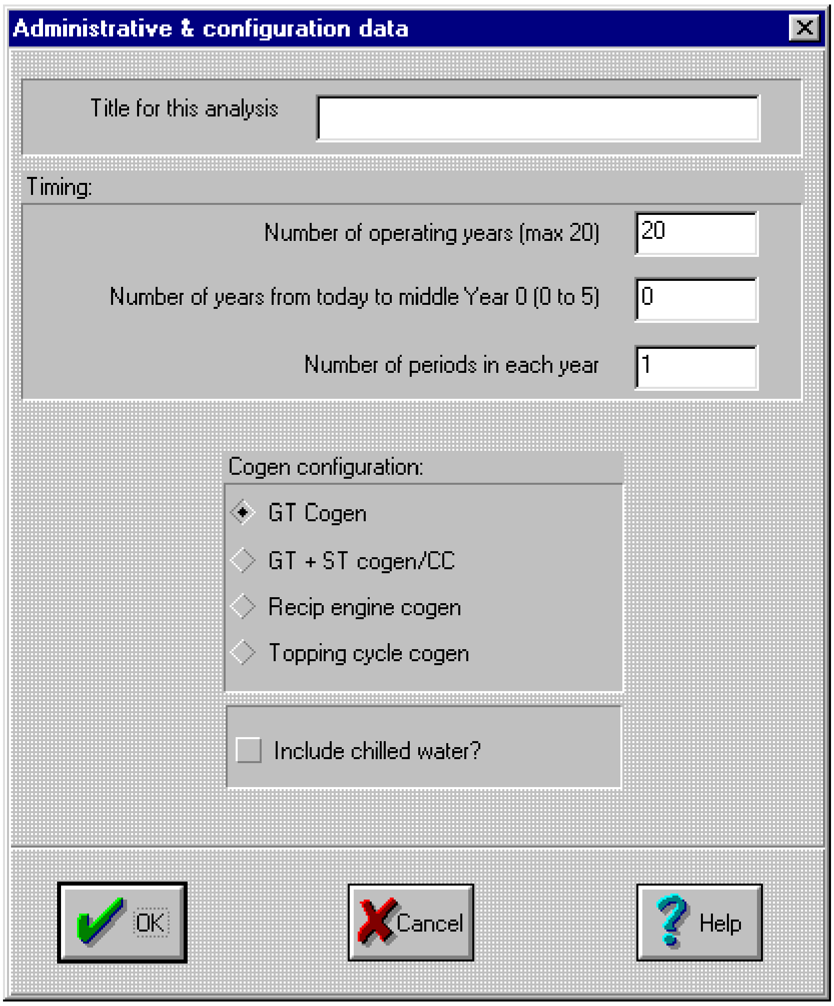
The Administration / configuration dialog box prompts the user to provide the following information:

Title for the analysis
Title which is a unique description of the analysis. Appears in the header of print-outs.

Number of operating years (max 20)
The expected operating life of the cogeneration system in years, with a maximum acceptable value of 20 years.

Number of periods in each year
Each year can be made up of several periods for which it is desired to use different flows or different tariffs. For example Peak, Offpeak, Summer etc). The program allows the year to be broken up into up to twelve periods.

Number of years from today to middle Year 0 (0 to 5).
The number of years from today to the middle of the capital investment year (Year 0), with a minimum value of 0 years and a maximum value of 5 years. Defaults to 0.



This parameter allows the user to escalate costs etc in nominal terms to the relevant dates noting that projects can take greater than one year from "today" to the date of commercial operation.

Cogen configuration

A selection must be made from gas turbine cogeneration (GT cogen), gas turbine + steam turbine cogeneration/combined cycle plant, reciprocating engine cogen (Recip engine cogen), or topping cycle cogeneration (Topping cycle cogen).

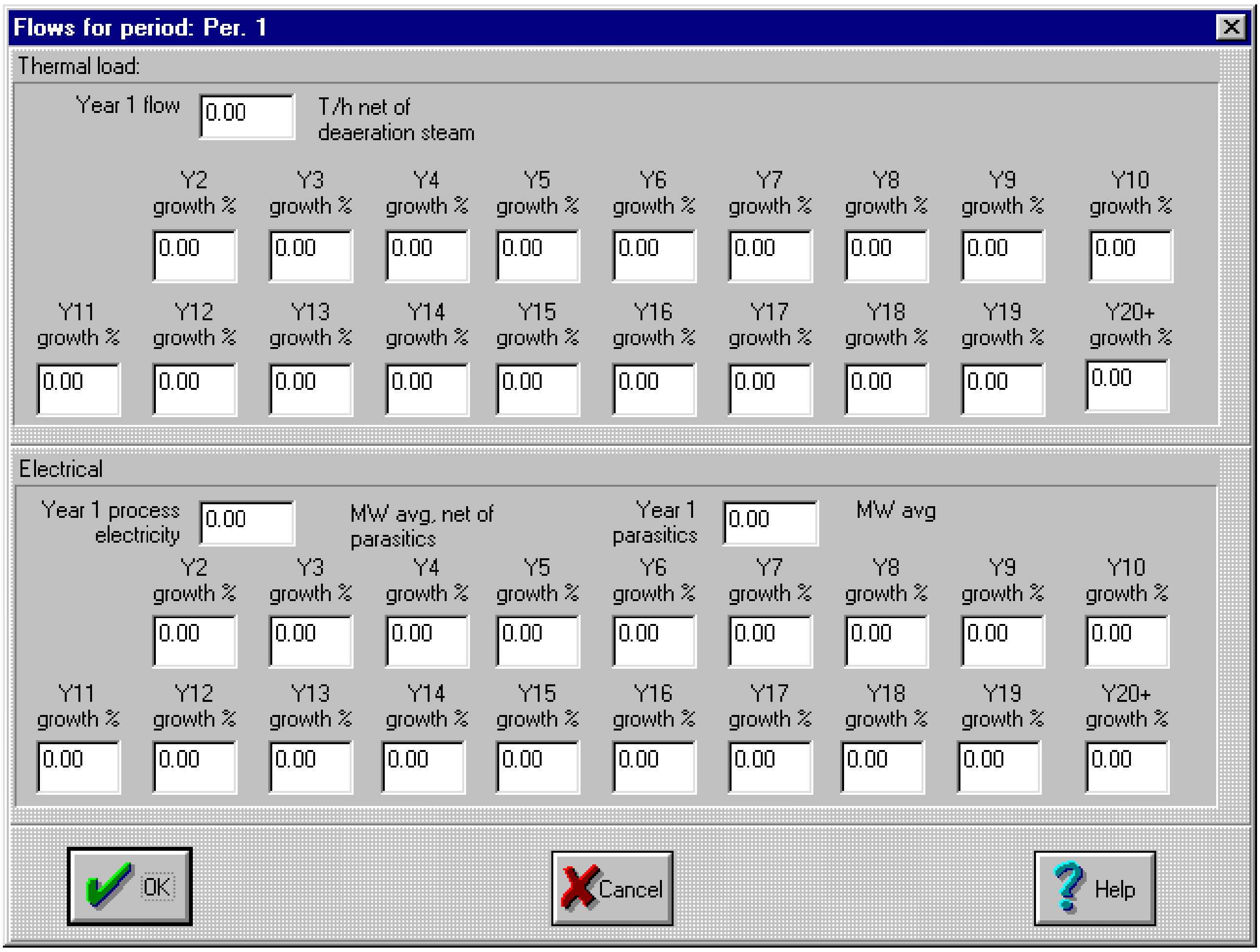
Refer to the Configurations section (Section 4.4).

Include chilled water?

Check this box if it is desired to consider the impact of moving chilled water load from electric chillers to absorption chillers and vice versa.

8.3 Benchmark flows and load growth dialog

The Benchmark flows and load growth dialog box appears up to twelve times, once for each operating period nominated.



The dialog box prompts the user to provide the following information:

Thermal load
User to provide the year 1 thermal load in tonnes per hour (pounds per hour), net of deaeration steam if this is applicable. Thermal load for consecutive years (i.e.. year 2 up to a maximum of year 20) is entered as a percentage growth on the previous years' thermal load.

This parameter is MWth in the case of hot water thermal load.

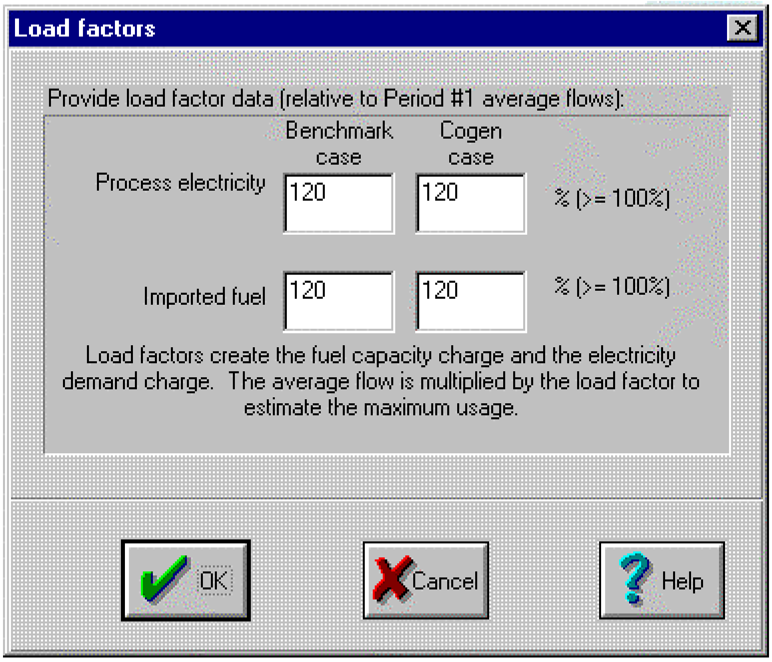
Electrical
User to provide the year 1 process electricity in MW average, net of parasitics, and year 1 parasitics in MW average. Electrical loads for consecutive years (i.e. year 2 up to a maximum of year 20) are entered as a percentage growth on the previous years' electrical loads.

Parasitics refers to the electricity consumed in the 'boiler-house' in raising the steam or hot water load (but not the chilled water load if applicable), for example in running boiler fans. These should not be included in the process loads as the cogen plant can often displace these parasitics. Normally these are negligible.

A note on chilled water
If chilled water flows are being analysed, then it is important to ensure that the steam or electricity required to operate the chillers in the benchmark case is included within the Thermal load and Electrical load entered in the Benchmark flows and load growth dialog. For example if the Chilled water period data dialog (Section 8.8) calls up 1000kWr (286T) of chilling in the Benchmark case, and that this is by electric chillers, then the Benchmark site electrical load needs to be at least 1000/3.5 = 286kW on top of the electricity used for other uses (this assumes a CoP for the electric chillers of 3.5).

In the Cogen case, if chilled water is generated differently than in the Benchmark case (eg by thermal (absorption) chillers in the Cogen case versus electric chillers in the Benchmark), then the program will adjust the site thermal and electricity requirement from those listed in the Benchmark case to suit (eg in the case noted, it will lower the electricity load and raise the thermal load in the Cogen case versus the Benchmark case).

8.4 Load factors dialog



The Load factors dialog box prompts the user to provide load factors for imported electricity and imported fuel for the benchmark and cogen cases. The load factors must be greater or equal to 100%.

These load factors are used to create the fuel capacity charge and the electricity demand charge.

Load factors are:

$$LoadFactor \equiv \frac{MaximumDemand}{AveragePeriod1\,flow}$$

Where:

MaximumDemand is the maximum usage on which demand charges are applied, and
AveragePeriod1Flow is the average flow entered by the user in the Period 1 flows (Benchmark flows and load growth dialog, Section 8.3)

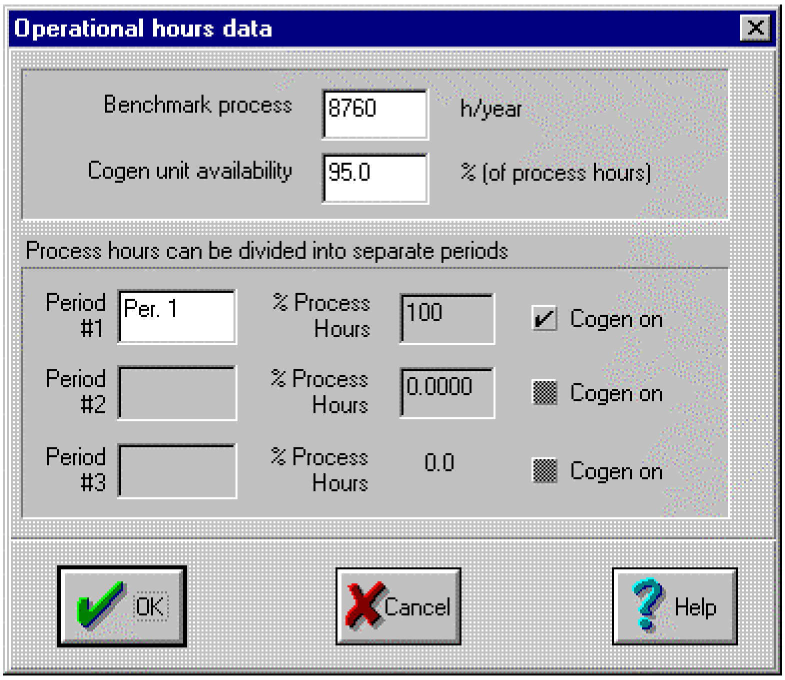
For example if a maximum demand charge is applied to electricity usage based on the highest electricity usage by the consumer in a year, and the user has entered three periods with average flows of:

Period	Name entered by user (say)	Average flow
1	Peak	5MW
2	Offpeak1	3MW
3	Weekend	0.5MW

If the maximum usage that the Consumer took was say 7MW, regardless of which period this occurred in, the user should enter a load factor of 7 / 5 = 140% in the relevant section of the Load factors dialog box.

Note that cogeneration can sometimes reduce the load factors (ie make them better) or might increase the load factors. Where the cogeneration plant is proposed to run for all periods of the year then it would be usual for an improvement in load factors to occur because of the high availability of most cogeneration plants.

8.5 Operating hours dialog



The Operational hours dialog box prompts the user to provide the following information:

Benchmark process
The benchmark (or existing case) process hours per year. Default is 8760 h/year.

Cogen unit availability
The percentage of process hours when the cogen unit is operating (i.e.. 100% - the % of time for scheduled and unscheduled maintenance). The default is 95%.

In addition, if the number of periods/year selected by the user in the Administration/configuration dialog (Section 8.2) is three or fewer, then the user is asked to define the breakdown of the process operating hours into the time periods by providing the following information:

If the number of periods per year is more than three, these boxes are greyed and a separate dialog appears to allow entry of the relevant parameters (Section 8.6).

Period #1 etc
Name given for that time period. Default is "Per. 1". If there were three periods these could be changed to peak, off-peak and shoulder for example to make the print-outs more readable.

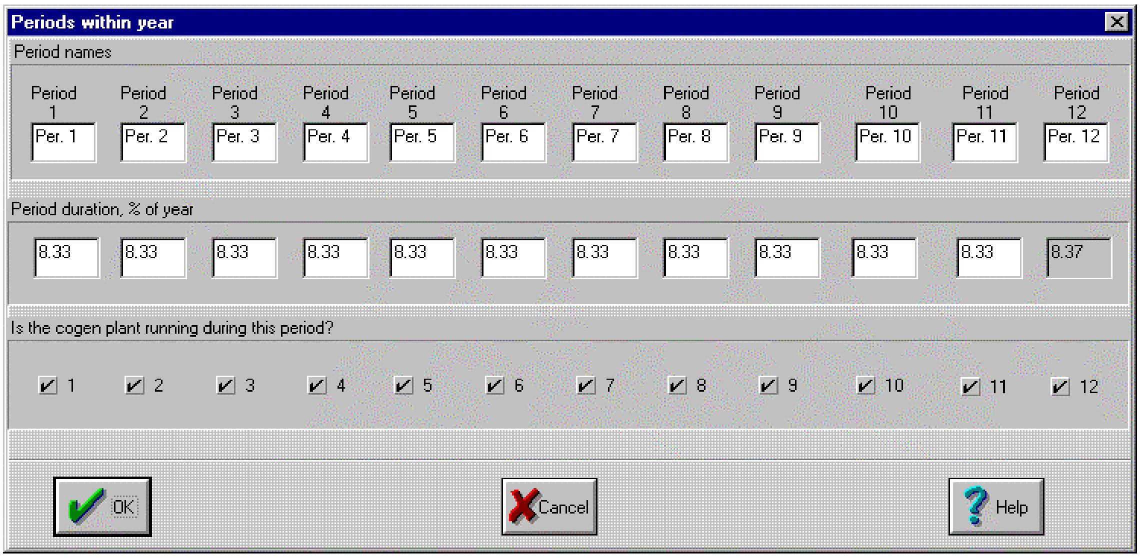
% Process Hours
The percentage of the benchmark hours taken up by that time period. Zero percent hours are allowed for up to two time periods to allow a reduced number of periods to be dealt with. The first period should not have zero hours.

Cogen on?
For some time periods, the user may elect not to run the cogeneration unit (for example if the marginal value of power for that period is less than the marginal cost of generation).

Note the cogeneration system is assumed to be off-line when the process is off-line, i.e. if the benchmark process hours are less than 8760 (24 x 365), the missing hours will be taken as being nil generation, nil steam, nil electricity (import or export), nil fuel etc etc.

If there is more than one cogeneration unit it is assumed that scheduled cogen downtime on each unit would be arranged so as to not be coincident with other units' downtime during process operating hours. Further the reliability is assumed such that the time when more than one cogen unit is down is negligible and is ignored

8.6 Period hours dialog



This dialog only applies if the number of periods in a year is more than three. If three or fewer, the parameters are included in the Operating hours dialog (Section 8.5).

Period names
Name given for that time period. Examples might be: Summer, Autumn, Winter and Spring, or into various categories of peak and offpeak hours. Selecting an appropriate name makes the print-outs more informative.

Period duration, % of year
The percentage of the benchmark hours taken up by that time period. Zero percent hours are allowed however the first period should not have zero hours.

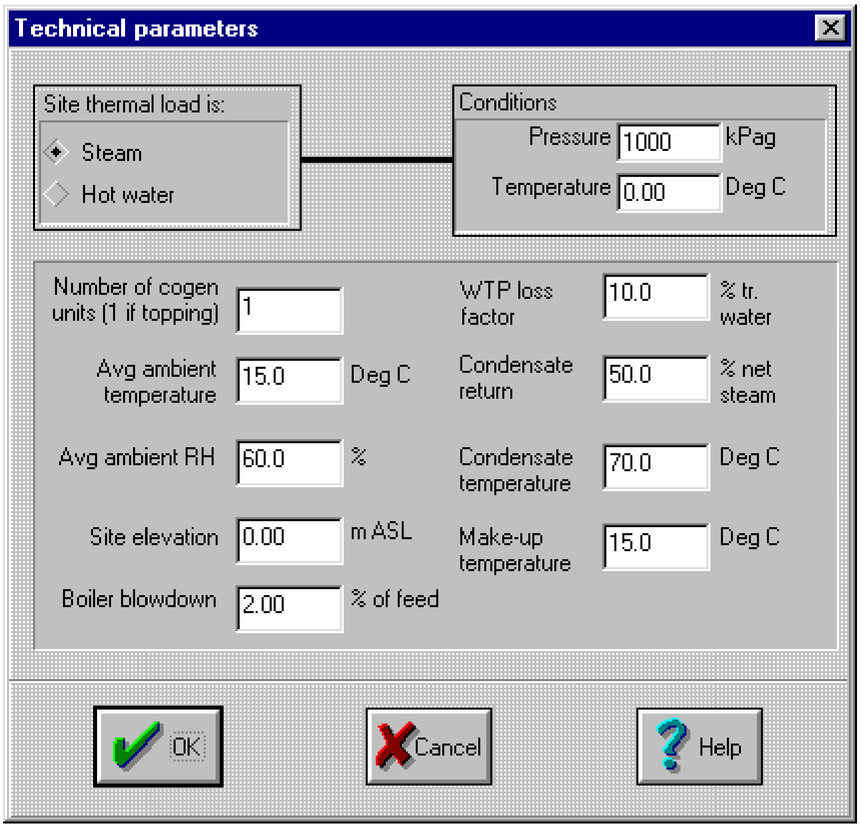
Is the cogen plant running during this period?
For each of the time periods, the user may elect not to run the cogeneration unit (for example if the marginal value of power for that period is less than the marginal cost of generation).

Note the cogeneration system is assumed to be off-line when the process is off-line, i.e. if the benchmark process hours are less than 8760 (24 x 365), the missing hours will be taken as being nil generation, nil steam, nil electricity (import or export), nil fuel etc etc.

If there is more than one cogeneration unit it is assumed that scheduled cogen downtime on each unit would be arranged so as to not be coincident during process operating hours. Further the reliability is assumed such that the time when more than one cogen unit is down is negligible and is ignored

8.7 Technical parameters dialog

The Technical parameters dialog box prompts the user to provide the following information:



Site thermal load is:
User must choose between steam and hot water.

Conditions
Site thermal load pressure in kPa gauge (psia), and temperature in degrees Celsius (Fahrenheit).

If steam is selected, selecting a steam temperature lower than the saturated steam temperature (for example zero) is acceptable and is a convenient way of entering saturated steam as the desired condition. At the time of calculation, the program will automatically adjust this temperature to saturation temperature for the selected pressure.

If hot water is the site thermal load type, the pressure entry box is hidden (not relevant). The temperature box is shown to enter the site hot water temperature (hot side). This parameter has a small impact on a waste heat boiler hot water generation capacity.

Number of cogen units
The number of cogen units modelled in the analysis. If topping cycle cogen is being modelled 1 is entered here.

Avg ambient temperature
The site all hours average (dry bulb) ambient temperature in degrees Celsius (Fahrenheit).

Avg ambient RH
The site all hours average ambient relative humidity, in %.

Site elevation
The site elevation in metres (feet) ASL.

Boiler blowdown
The percentage of the feedwater flow lost in the boiler as boiler blowdown. Sent to sewer.

WTP loss factor
The loss from the water treatment plant as a percentage of water treated.

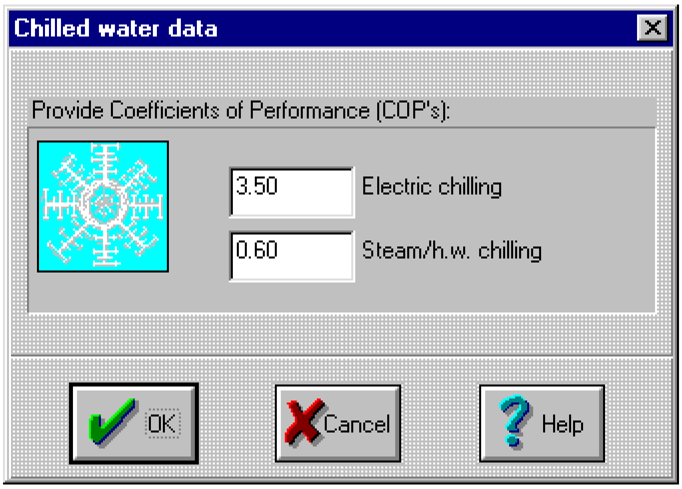
Condensate return
The percentage of the steam or hot water sent to process which is returned to the cogeneration plant as condensate.

Condensate temperature
The temperature of the condensate on its return to the cogeneration plant in degrees Celsius (Fahrenheit).

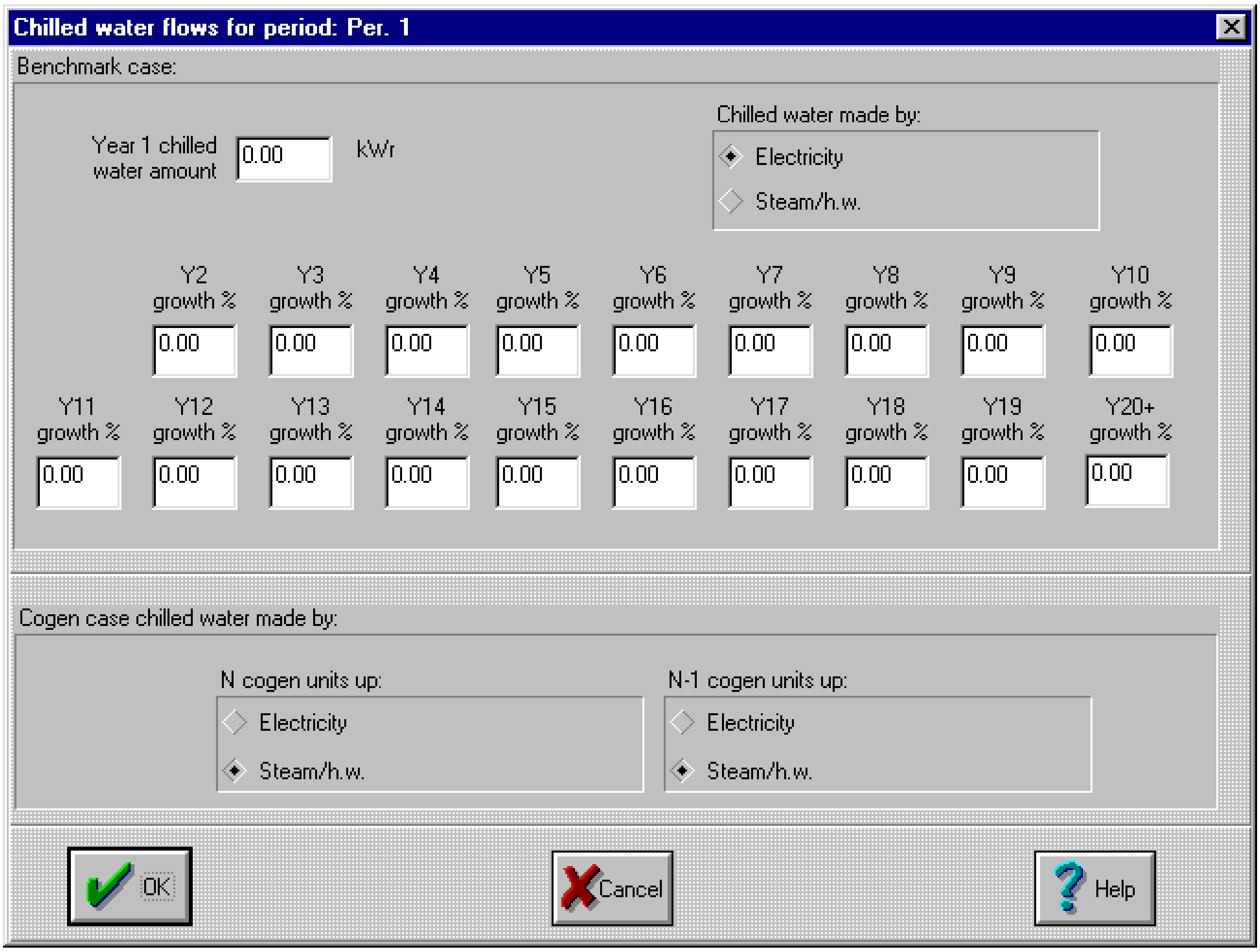
Make-up temperature
The temperature of the make-up water added to the steam or hot water cycle in degrees Celsius (Fahrenheit). The make-up water replaces that lost to boiler blowdown and the like.

8.8 Chilled water parameters dialog

The Chilled Water Parameters dialog provides the Coefficients of Performance for chillers in the electric chilled water case and in the steam/hot water (absorption) chiller case.



8.9 Chilled water flows dialog



If chilled water is selected in the administration/configuration dialog, then when the Chilled water parameters menu item is selected, the Chilled water flows dialog appears once for each operating period to allow the user to define the chilled water flows for that period.

In a cogeneration system evaluation where the site uses chilled water, switching the production of chilled water from electricity to thermal sources and vice versa can change the optimum size of the cogeneration plant to be installed.

Chilled water flows are firstly defined for Year 1 in for that period (in kWr or Tons). Should it be anticipated that chilled water flows will change through the life of the project, then growth (which might be negative) can be applied using this dialog box to approximate the change.

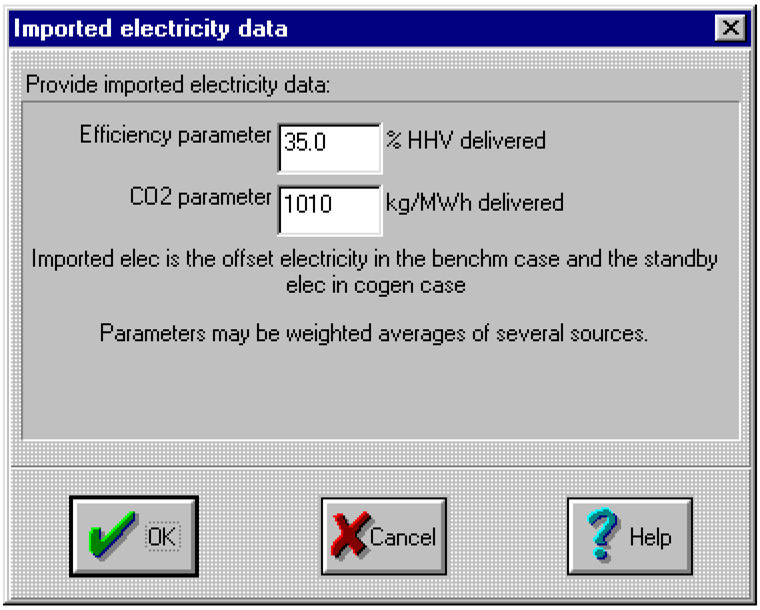
Growth is a percentage change in flow for that year relative to the previous year.

The opportunity is provided for the chilled water flow to be identified as being provided by electricity (electric chillers) or by steam/hot water (absorption) chillers.

In the cogeneration case, the chilled water production method can be different when all “N” of the cogeneration units are up and when one unit is down (“N-1”).

8.10 Import electricity dialog

Imported electricity is the offset electricity in the benchmark case, and the standby electricity in the cogeneration case. Parameters may be provided as weighted averages of several sources.



The Imported electricity dialog box prompts the user to provide the following information:

Efficiency parameter
This is the efficiency of the technology used to generate the purchased electricity with transmission and distribution (T&D) losses accounted for. For example, for brown coal thermal generation with 4% T&D losses, the efficiency parameter would be:

$$\eta = 25.6\% / 1.04$$
$$= 24.6\%$$

CO_2 parameter
The carbon dioxide produced in kg per MWh (lbs per MWh) of electricity delivered.

Remember to allow for transmission and distribution losses on the imported electricity to the comparable point in the system. For example 4% T&D losses would increase the effective CO_2 parameter by 4% from the ex-station value to the cogeneration point in the grid. This assumes that if the cogeneration plant exports electricity, that the exported electricity is still used locally to the cogeneration plant.

The efficiency and CO_2 parameter for purchased electricity (base case and standby for cogen) are calculated from the parameters entered in the user dialog box. In the case of Australia, defaults are for a benchmark of black coal as the marginal alternative generation technology (consistent with the first phase of the Australian Greenhouse Gas Abatement Program data from the AGO). The user can proportion offset generation to black coal, brown coal, gas conventional, gas combined cycle, gas simple cycle, oil conventional and hydro. Addition is made for offset transmission & distribution (T&D) losses (default 6%). The following table (which excludes T&D adjustment) might provide guidance:

Technology	Fuel	Fuel carbon % (ultimate, as fired, by mass)	Fuel heating value GJ/T HHV as fired	Station efficiency % avg net HHV	CO_2 kg/MWh avg net ex-station
Black coal thermal	Black coal	63.0%	23.98	35.9%	930
Brown coal thermal	Brown coal	25.6%	9.95	27.7%	1,230
Gas thermal	Natural gas	70.6%	51.20	38.0%	479
Oil thermal	Fuel oil	89.0%	44.10	38.0%	694
Gas turbine simple cycle	Natural gas	70.6%	51.20	30.0%	606
Gas turbine combined cycle	Natural gas	70.6%	51.20	48.0%	379
Hydro	"Water"	0.0%	N/A	N/A	0

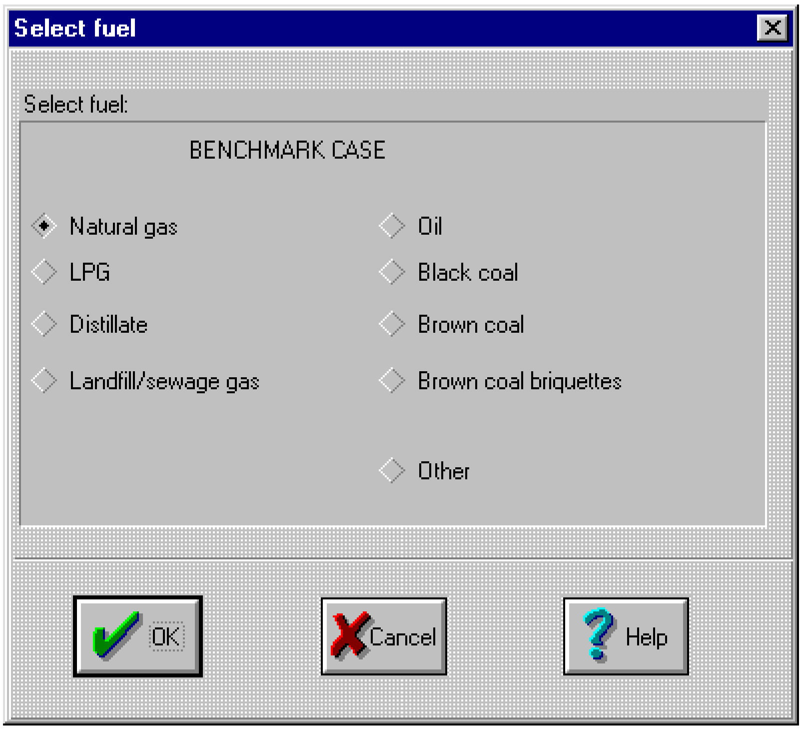
The program assumes 100% carbon conversion to CO_2 in each case (i.e.. nil CO, nil carbon-in-ash). Methane loss from gas reticulation system, gas gathering and coal mining is ignored.

8.11 Fuel selection dialog

The Fuel selection dialog box appears is shown for the benchmark case and for the cogen case. Different fuels may be used for each case.

The user is prompted to select a fuel from the following list:

- natural gas
- LPG
- distillate
- landfill / sewage gas
- oil
- black coal
- brown coal
- brown coal briquette
- other



If "other" is selected as a fuel, the Fuel properties dialog box dialog box appears for the user to enter the appropriate parameters. Note that oil and the solid fuel selections are not available for the gas turbine or reciprocating engine option in the cogen case.

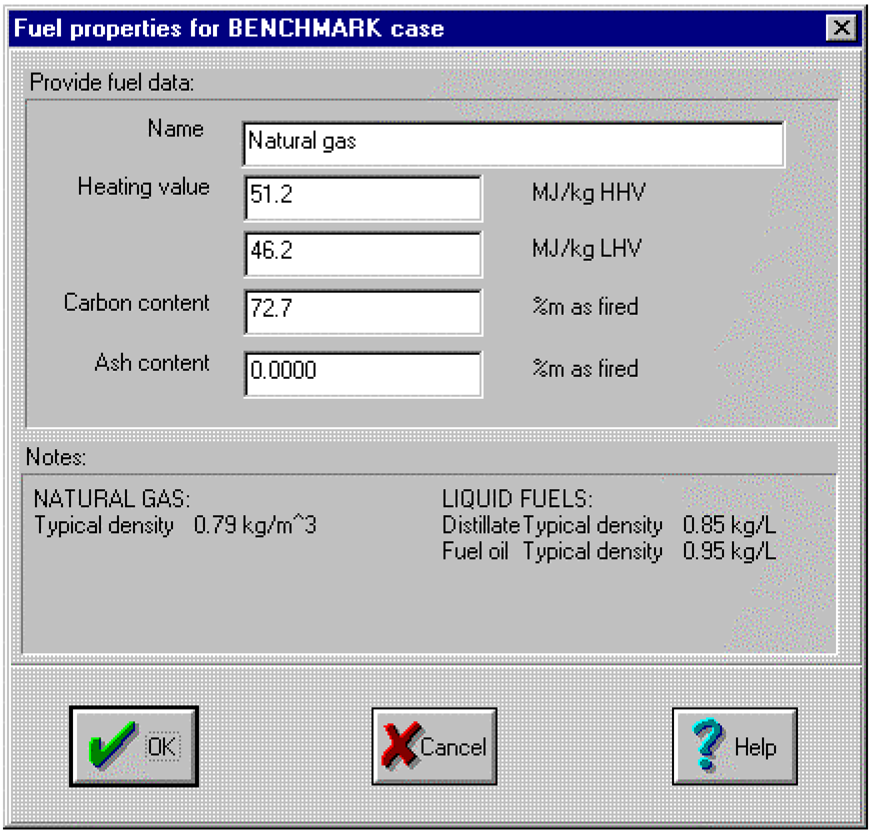
Separate fuels may be used in the Benchmark and Cogen cases, although multiple fuels are not provided for (e.g.. a cogen case burning natural gas in the gas turbine and oil in the auxiliary boiler is not allowed, however oil can be burned in the boiler in the Benchmark and natural gas in the gas turbine and auxiliary boiler in the Cogen case).

The user is responsible of course for ensuring that fuels and their safety and handling systems are appropriate for the installation envisaged.

Fuel costs are entered in the tariffs section (Section 8.29).

8.12 Fuel properties dialog

The Fuel properties dialog box appears if the user selects “other” from the Fuel selection dialog box or if the user wishes to slightly modify the default parameters.



The dialog box prompts the user to provide the following information:

Name
The name of the user defined fuel.

Heating Value
The heating value of the user defined fuel in MJ/kg HHV and MJ/kg LHV (or btu/lb).

Carbon content
The carbon content of the fuel, as a percentage of the fuel mass as fired.

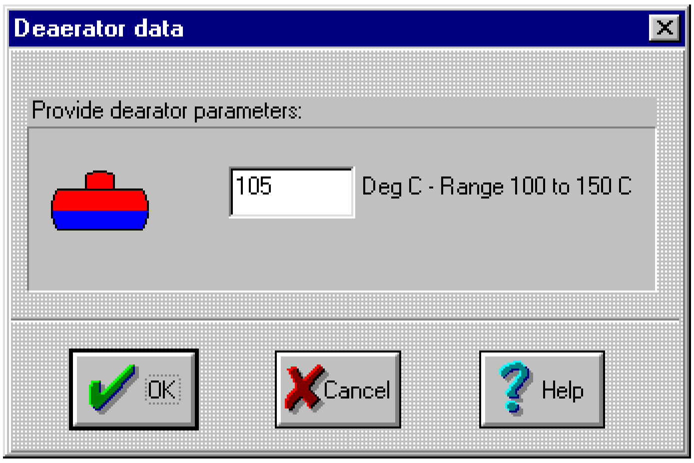
Ash content
The ash content of the fuel, as a percentage of the fuel mass as fired.

Typical fuel properties are as follows:

Fuel	HHV (MJ/kg)	LHV (MJ/kg)	Carbon Content (%m as fired)	Ash Content (%m as fired)
Natural Gas	51.200	47.100	70.6%	0.0%
LPG	50.020	46.090	82.1%	0.0%
Distillate	45.342	44.969	87.2%	0.0%
Landfill / Sewage Gas	25.520	22.980	49.2%	0.0%
Oil	43.245	40.840	87.9%	0.1%
Black Coal	23.975	22.811	63.4%	21.4%
Brown Coal	9.950	8.030	25.6%	0.6%
Brown Coal Briquette	22.400	21.300	41.4%	2.1%

8.13 Deaerator parameters dialog

The Deaerator parameters dialog box prompts the user to provide the deaerator temperature in degrees Celsius (Fahrenheit). The temperature must be in the range of 100°C to 150°C (212°F to 302°F).

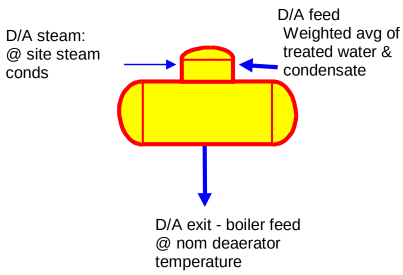


The deaerator dialog box is used for both the Benchmark and the Cogen cases when the site thermal usage is steam (not used for hot water).

The deaerator object impacts on:

- Gross steam (= net site steam + deaerator steam).
- Boiler feed conditions.

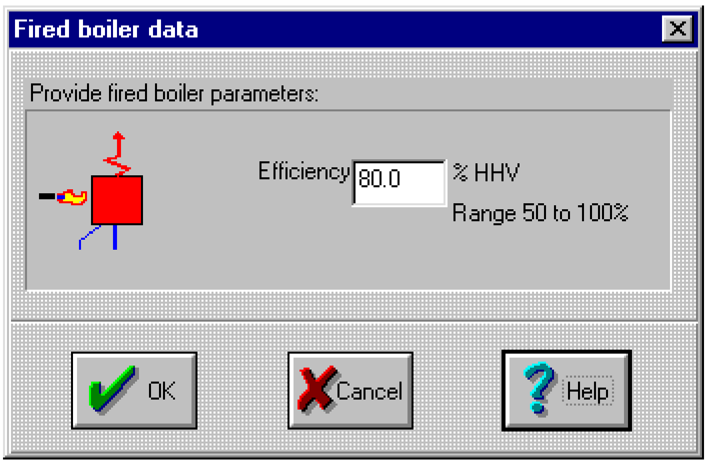
For the cogen cases selected, assuming constant blowdown, no condensing steam turbine, and no steam injection, the deaerator heat balance is the same between the cogen and benchmark cases. Only one instance is required. This ignores the impact of desuperheater spray flow reducing boiler blowdown (second order effect), which only applies for the topping cycle case. Where a condensing steam turbine is applied (which can only be within the Gas Turbine + ST configuration), the dearator flow can vary between the Benchmark case and the Cogeneration case.



8.14 Auxiliary boiler parameters dialog

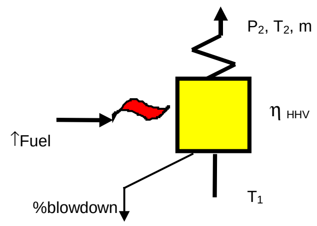
The Auxiliary boiler parameters dialog box prompts the user to provide the boiler efficiency in % HHV. This efficiency must be in the range of 50% to 100% HHV.

This dialog box data applies for the benchmark boiler and for the cogeneration case auxiliary boiler (if any).



The entered input parameters are:

Parameter	Units	Default	Notes
Steam pressure	kPag (psia)	N/A	Set from site conditions
Steam temperature	°C (°F)	N/A	If $T<T_{sat}$, T_{sat} used Set from site conditions
Steam flow required	T/h (lbs/h)	N/A	Set from site conditions
Feed temperature	°C (°F)	N/A	Set from site conditions
Boiler efficiency	% HHV	80%	User entered, 50-100%
Boiler blowdown	% feed	N/A	From Parameters



Only the efficiency needs to be entered in this dialog box, the remaining parameters are taken from the relevant entries in other dialog boxes.

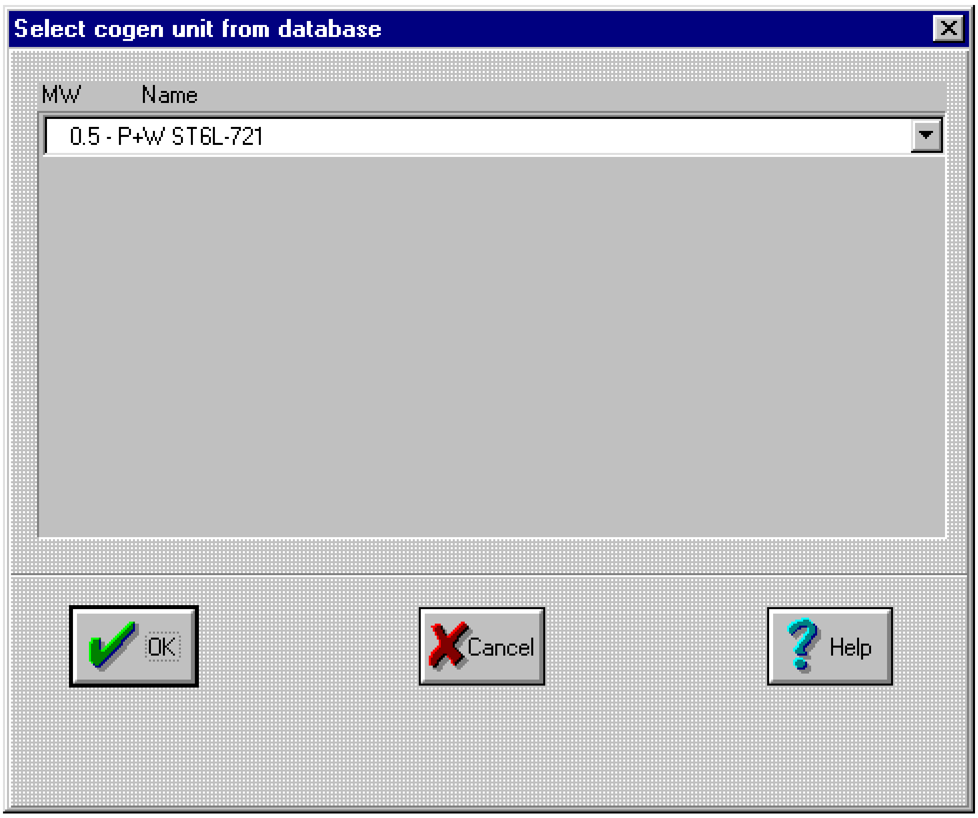
For topping cycle configurations, boiler steam conditions are taken from the Topping cycle HP steam conditions dialog. For other configurations, the steam conditions are from the site steam conditions dialog box.

The output parameters provided to the hourly flows section of the analysis outputs are:

Parameter	Units	Notes
Feed mass flow	T/h (lbs/h)	
Blowdown mass flow	T/h (lbs/h)	
Fuel flow	GJ/h HHV	
Ash flow	T/h db (lbs/h)	db stands for dry-basis
CO_2 emissions	T/h (lbs/h)	

8.15 Cogen unit selection dialog

The Cogen unit selection dialog box applies to gas turbine and reciprocating engine cogeneration cases only (i.e.. not applicable to topping cycle steam turbine cogeneration).



A drop down list displays a selection of gas turbines or reciprocating engines for the user to select from. Selection of non-listed units can be made using the Cogen unit parameters dialog box. Refer to the Gas turbine parameters dialog or the Reciprocating engine parameters dialog as applicable.

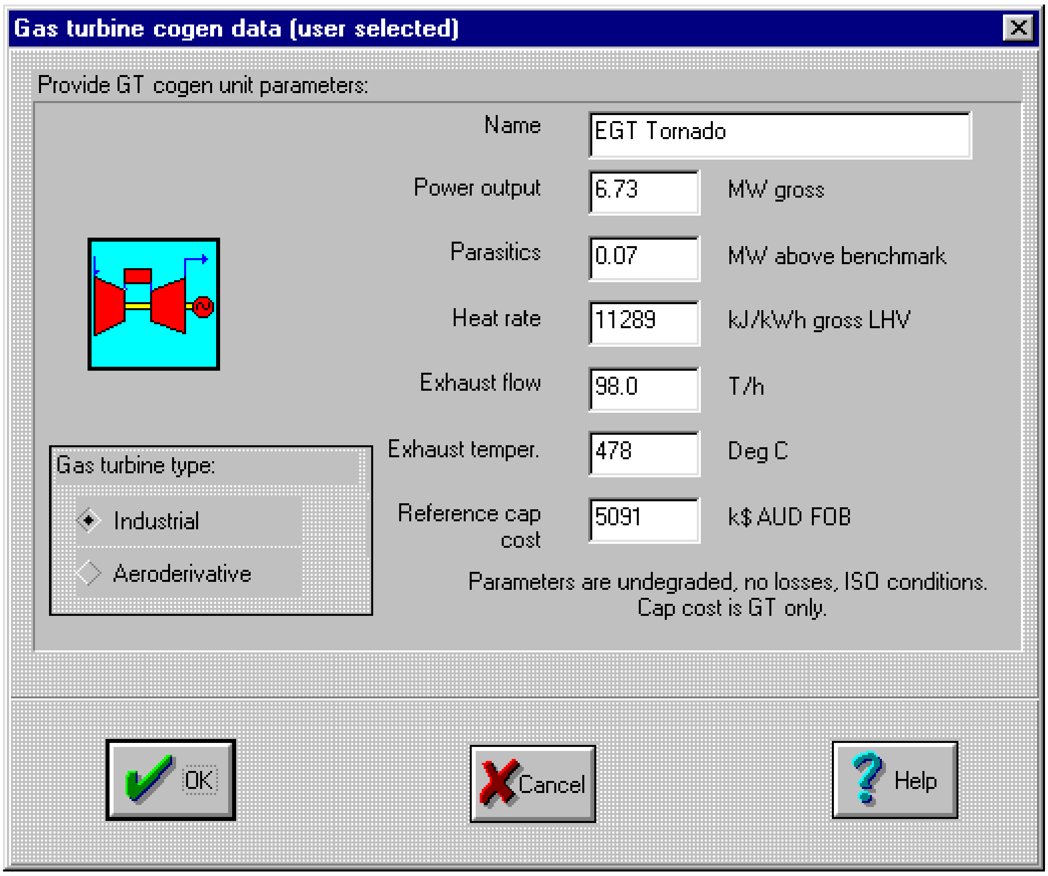
Notes regarding gas turbine cogen:

1) Gas turbines are not steam injected.
2) Waste heat boilers (WHB's) are single pressure (unless the gas turbine + steam turbine configuration option is selected).
3) Gas turbine parameters above are at ISO conditions, no losses (4"/4"), clean-as-new.
4) Parameters are corrected for degradation etc by the program.
5) Gas turbine parameters for a range of units are stored in a file, user selects a unit base on gas turbine name and output, user can modify file for future use. User can modify standard parameters via the dialog box.

Notes regarding Recip cogen:

1) Recips are spark ignited single fuel.
2) Waste heat boilers are single pressure. If the site is a hot water site, allow heat capture from jacket water and lube oil recovery in addition to the amount that can be raised by exhaust gas.
3) No specific degradation allowance is added.

8.16 Gas turbine parameters dialog



The Gas turbine parameters dialog box appears when the user is running a gas turbine cogen or a gas turbine + steam turbine cogeneration / combined cycle analysis and provides the opportunity for the user to adjust the default values for a particular unit, or even to enter data for a different unit not in the database.

The dialog box prompts the user to provide the following information, note that all parameters are to be undegraded, no losses and at ISO conditions:

Name
The name of the user selected gas turbine cogeneration unit.

Power output
The gross power output of the unit in MWe.

Parasitics
The internal power consumption of the unit, in MW above the benchmark. This is added to the benchmark parasitics. Allow for gas compressor power requirements if applicable. Typical industrial gas turbines in the <10MW range require approximately 2000-2500 kPag (300 to 375psi) supply gas pressure. Many aeroderivatives and advanced gas turbines require higher gas pressures.

Heat rate
The gross heat rate of the unit, in kJ/kWh (btu/kWh) LHV.

Exhaust flow
The exhaust gas massflow of the unit in tonnes per hour (lbs per hour).

Exhaust temperature
The exhaust gas temperature in degrees Celsius (Fahrenheit).

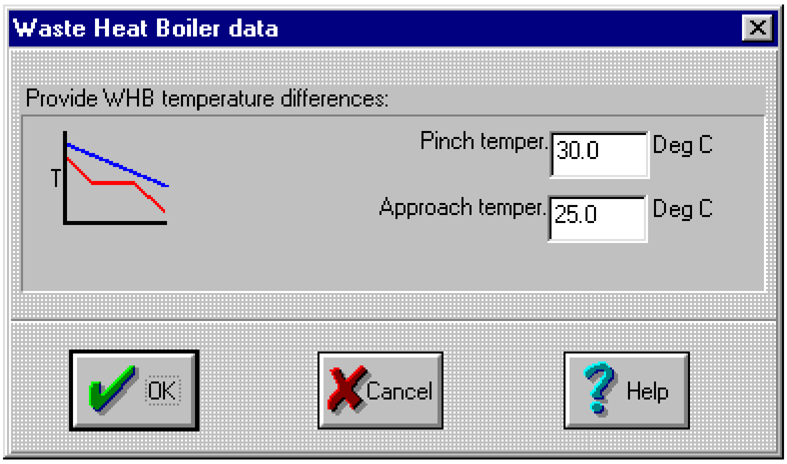
Reference capital cost
The capital cost of the gas turbine unit only in k$ AUD (USD) FOB. This is the ex-works cost (in Australian dollars) excluding shipping, installation etc. Costs should be in present day terms.

The reference capital cost in the database is indicative only. The user should consult with the manufacturer for up to date parameters at an appropriate time in the analysis.

Industrial/aeroderivative selection
The selection of a gas turbine as an industrial or aeroderivative type primarily affects the default maintenance cost assumptions that the program makes in the tariffs dialog.

8.17 Waste Heat Boiler parameters dialog

The Waste Heat Boiler parameters dialog box prompts the user to provide the following information:



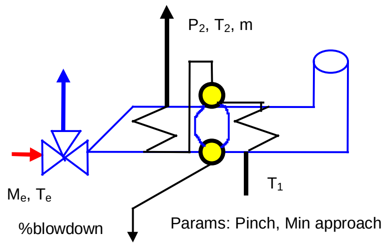
Pinch temperature
The pinch temperature is the difference between the exhaust gas temperature and the water temperature at the entrance of the boiler drum. The pinch point is inversely proportional to boiler surface area, and hence boiler cost. Practical values of pinch points for waste heat boilers range between 8°C and 30°C (15°F to 30°F).

Approach temperature
The approach temperature is the temperature difference between the exhaust gas and the steam at the superheater exit. The default value is 25°C (45°F).

For gas turbine cogeneration and reciprocating engine cogeneration, the Waste Heat Boiler (WHB) is a single pressure boiler with economizer. The WHB is not supplementary fired although this effect is approximated by the auxiliary boiler firing if the WHB capacity is insufficient for the desired site load.

For gas turbine + steam turbine cogeneration/combined cycle arrangements, the option exists for selection of two pressure waste heat boilers.

The WHB is assumed to be fitted with a dump stack and damper. This could also be done with a dump condenser. Other than that cooling tower make-up and blowdown would increase with this alternative, primary cost and revenue variables would be unchanged.



The parameters are:

Parameter	Units	Default	Notes
Steam pressure	kPag (psia)	N/A	Set from site conditions
Steam temperature	°C (°F)	N/A	If $T<T_{sat}$, T_{sat} used Set from site conditions
Desired steam flow	T/h (lbs/h)	N/A	Set from site conditions
Feed temperature	°C (°F)	N/A	Set from site conditions
Pinch point	°C (°F)	12°C (22°F)	User entered
Minimum approach	°C (°F)	25°C (45°F)	User entered
Boiler blowdown	% feed	N/A	From Parameters

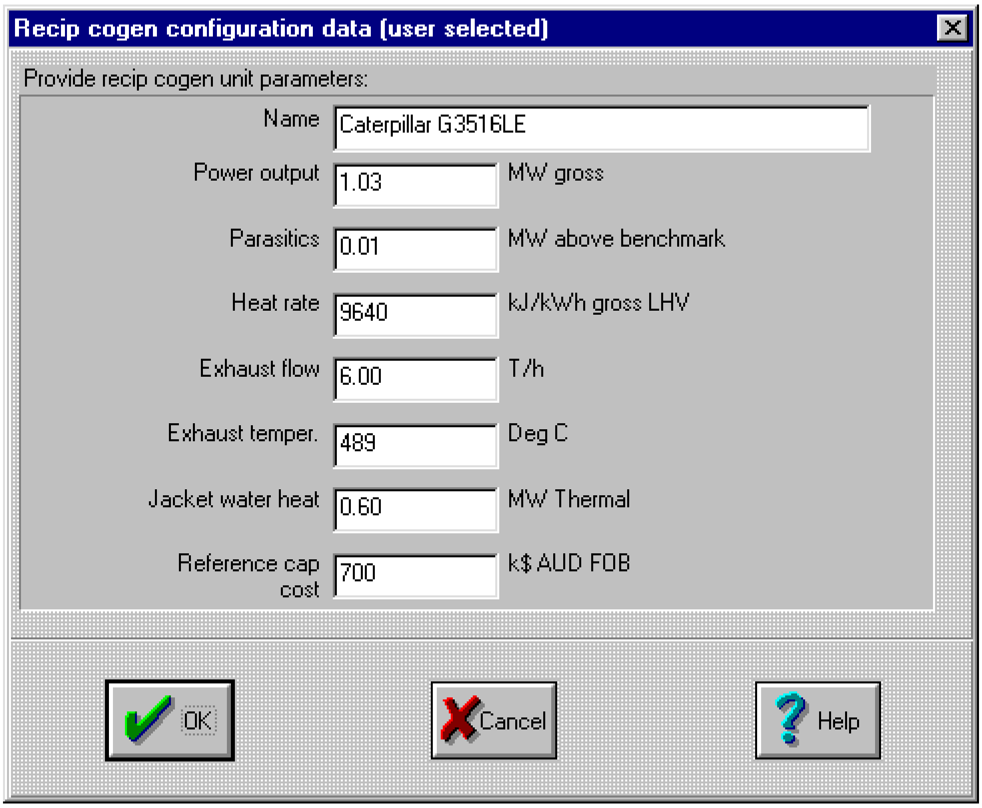
Note that Pinch point is used to size the evaporator surface area. It is assumed that a boiler would be procured to handle a peak steam requirement and hence surface area would be calculated as the maximum that the engine could support at the entered steam conditions. Typically, it is assumed that load matching provision is provided by a dump stack or dump condenser.

Minimum approach is a flag that only results in a warning message unless the selected steam conditions are higher than the exhaust temperature (in which case a warning is generated and the amount of steam raising is set to nil).

The output parameters displayed in the hourly flows calculation outputs are:

Parameter	Units	Notes
Maximum steam raised	T/h (lbs/h)	Refer to note above
Actual steam raised	T/h (lbs/h)	Minimum of desired & maximum steam flows
Feed mass flow	T/h (lbs/h)	Based on Actual steam raised
Blowdown mass flow	T/h (lbs/h)	Based on Actual steam raised

8.18 Reciprocating engine parameters dialog



The Reciprocating engine parameters dialog box prompts the user to provide the following information, note that all parameters are to be undegraded, no losses and at nominal 15°C (59°F), sea level elevation conditions:

Name
The name of the user selected recip cogeneration unit.

Power output
The gross power output of the unit in MWe.

Parasitics
The internal power consumption of the unit, in MW above the benchmark.

Heat rate
The gross heat rate of the unit, in kJ/kWh (btu/kWh) LHV.

Exhaust flow
The exhaust gas massflow of the unit in tonnes per hour (pounds per hour).

Exhaust temperature
The exhaust gas temperature in degrees Celsius (Fahrenheit).

Jacket water heat
The jacket water heat utilized for hot water generation in MWthermal. This parameter is not used if the site thermal load is steam.

Reference capital cost
The capital cost of the reciprocating engine unit only in k$ AUD (USD) FOB.

The reference capital cost in the database is indicative only. The user should consult with the manufacturer for up to date parameters at an appropriate time in the analysis.

Note that the algorithms used for Reciprocating engine performance does not adjust for degradation or ambient temperature. The effects can vary depending on whether water cooled turbocharger aftercoolers etc are used and the derivation of the cooling water for the system (closed cycle, evaporative or air cooled etc). Consult the manufacturers at a suitable stage in the analysis for actual site ratings.

8.19 Topping cycle HP steam conditions selection dialog

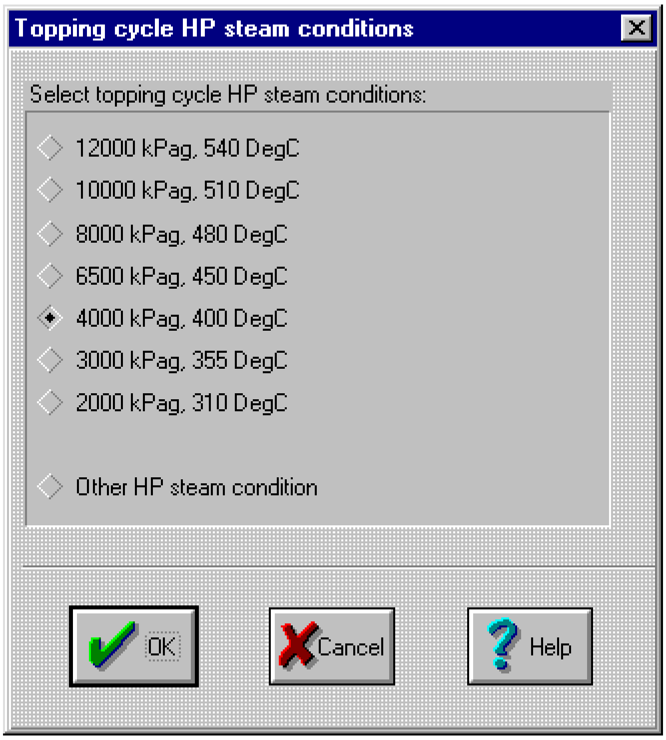
The Topping cycle HP steam conditions selection dialog box appears only when topping cycle cogen has been selected as the cogen configuration.

The steam conditions listed are points on the expansion line of a typical non-reheat steam turbine

The user must select from the listed HP steam conditions, or select "Other HP steam condition". When "Other HP steam condition" is selected, the "User defined topping cycle steam conditions" dialog box appears (Section 8.20).

Parameters for topping cycle cogen (excluding inherited parameters) are:

Parameter	Units	Notes
HP steam pressure	kPag (psia)	Default 4,000 kPag (600psia)
HP steam temperature	°C (°F)	Default 400°C (750°C)



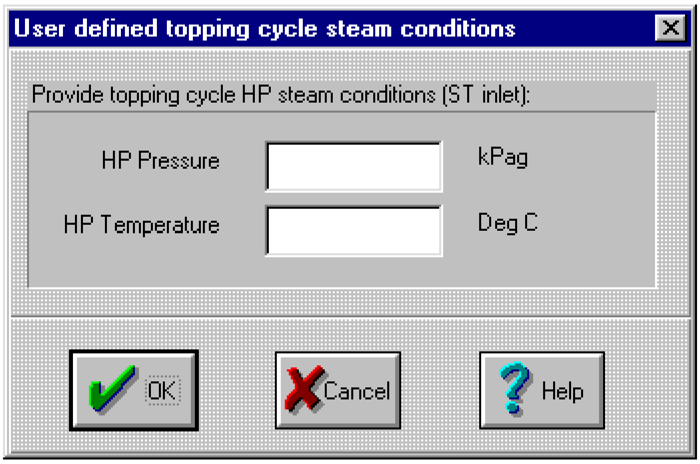
Topping cycles are typically based on certain standard steam conditions (which coincides with the expansion line of a non-reheat condensing steam turbine through to typical exhaust conditions). These are provided in a selection box, the user only needs to enter actual conditions if the "Other HP steam condition" option is selected. Note that steam conditions are nominal ignoring piping losses etc.

The standard steam conditions offered are as shown.

Ensure that the selected steam conditions are higher than the site steam conditions (in both temperature and pressure).

Note that higher steam conditions leads to higher steam turbine outputs, but also to higher capital cost, higher feed water quality requirements and often to increased complexity in support systems.

8.20 User defined topping cycle steam conditions dialog



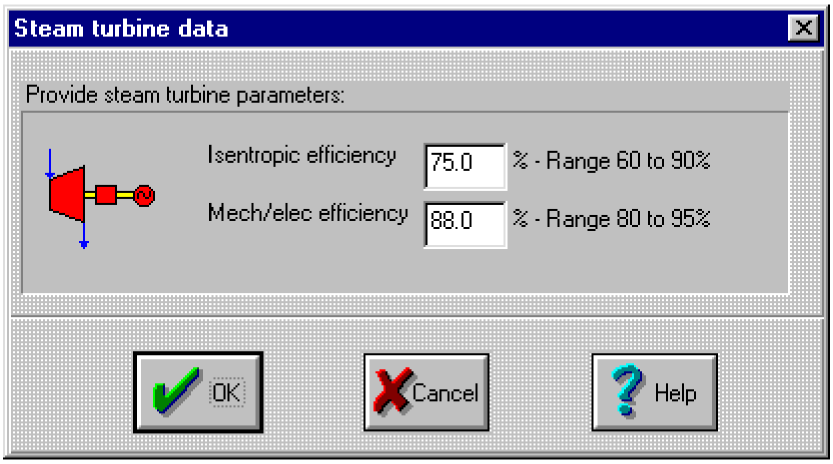
The "User defined topping cycle steam conditions" dialog box appears when "Other HP steam condition" is selected from the Topping cycle HP steam conditions selection dialog box.

The dialog box prompts the user to provide the following information:

HP Pressure
The pressure of the high pressure steam at the steam turbine inlet in kPa gauge (psia).

HP Temperature
The temperature of the high pressure steam at the steam turbine inlet in degrees Celsius (Fahrenheit).

8.21 Steam turbine parameters dialog



The Steam Turbine parameters dialog box appears when "topping cycle cogen" or "gas turbine + ST/CC" has been selected as the cogen configuration.

The dialog box prompts the user to provide the following information:

Isentropic efficiency
The isentropic efficiency of the back pressure steam turbine as a percentage. Acceptable values are between 60% and 90%. Isentropic efficiency represents the steam turbine expansion curve's deviation from an expansion curve of constant entropy (i.e. from an ideal no loss turbine).

Steam turbine isentropic efficiency = (h1 - h2) / (h1 - h2*)
where: h1 = enthalpy of steam at steam turbine inlet
h2 = enthalpy of steam at steam turbine outlet
h2* = enthalpy of steam at steam turbine outlet for isentropic expansion

Mech/elec efficiency
The mechanical / electrical efficiency of the steam turbine as a percentage. Acceptable values are between 80% and 95%.

Mech/elec efficiency = 100% - % mechanical and electrical losses

The back pressure steam turbine is a simple non-extraction steam turbine. The exhaust pressure is set from the site steam pressure requirement (piping and valving losses ignored). The exhaust steam pressure is calculated from a linear (Mollier chart) expansion line through the steam turbine using the user selected isentropic efficiency.

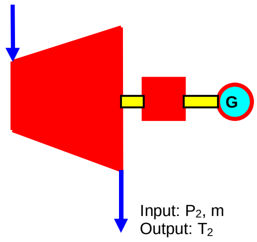
Output electricity is calculated by multiplying the enthalpy difference through the steam turbine by the mass flow and the mechanical efficiency of the steam turbine.

For a condensing steam turbine as might be selected in the "gas turbine + ST cogen/CC" arrangement (Section 8.2) the methodology is largely the same except the exhaust conditions for the steam turbine are derived from the condenser pressure appropriate for the site cooling arrangements.

For small steam turbines as are envisaged, the mechanical efficiency includes allowances for:

- Mechanical efficiency of steam turbine itself (glands, bearings etc).
- Mechanical efficiency of gearbox (small turbines usually operate at greater than 2 pole synchronous speed).
- Electrical efficiency of generator to convert shaft power to generator terminals electrical output.

Steam leakage is ignored. The steam turbine is assumed infinitely capable (i.e. is sized to pass the steam required) and is constant efficiency.



If the site steam conditions cannot be generated with the selected inlet conditions, then an error is flagged and output power is set to nil.

The entered input parameters are:

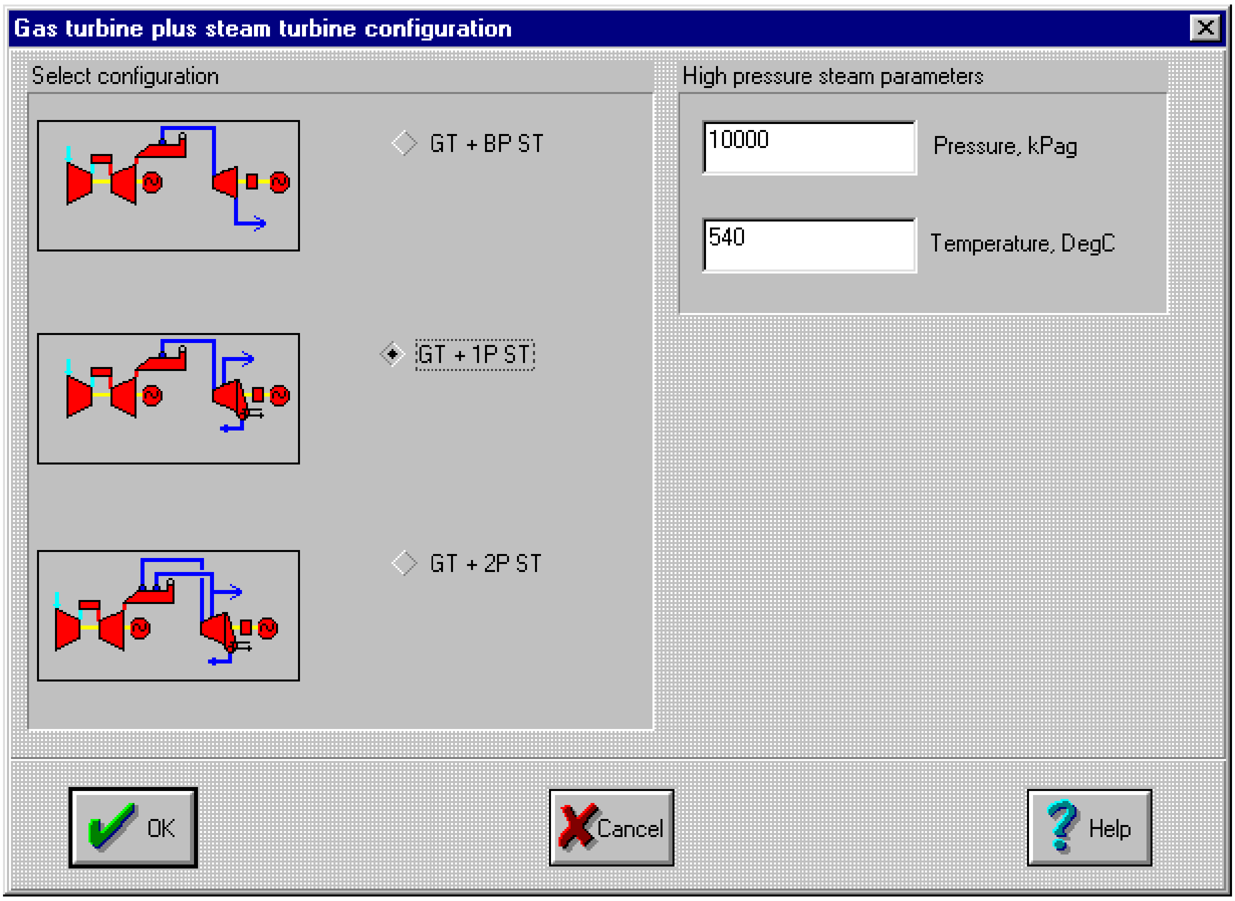
Parameter	Units	Default	Notes
Steam Outlet Pressure	kPag (psia)	N/A	Set from site conditions
Steam Inlet Pressure	kPag (psia)	N/A	From Topping Cycle conditions
Steam Inlet Temperature	°C (°F)	N/A	From Topping Cycle conditions
Steam flow	T/h (lbs/h)	N/A	Set from site conditions + deaerator conditions
η_s	%	80%	User entered, range 60-90%
η_m	%	91%	User entered, range 60-95%

Errors are flagged if:

- Outlet steam conditions not possible for given inlet conditions, Power = nil.

No degradation is applied to the steam turbine. No inlet valve losses are applied. Assume both these parameters in isentropic efficiency if the user deems important.

8.22 Gas turbine + steam turbine configuration dialog



The Gas turbine + steam turbine configuration dialog is displayed when "GT + ST cogen/CC" is selected as the configuration in the Admin/configuration dialog. The dialog is displayed under the Cogen | Unit parameters menu selection.

Three types of configurations are provided for as shown:

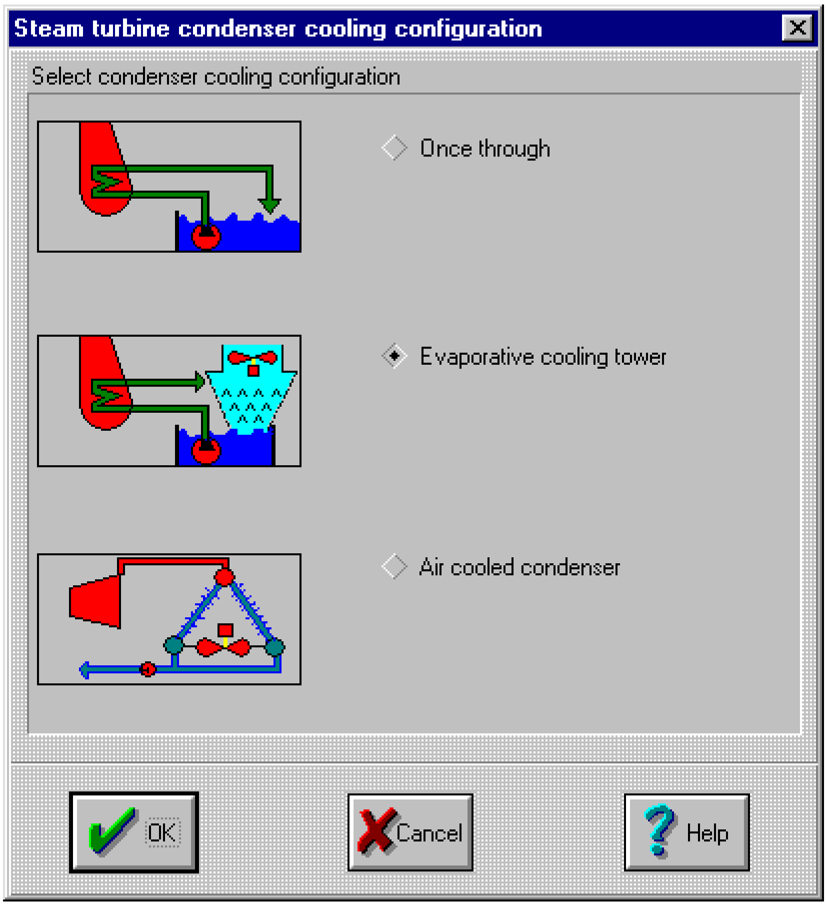
- GT + BP ST – topping cycle cogen using a back pressure steam turbine exhausting at the site steam conditions
- GT + 1P ST – a cogen/combined cycle arrangement with a single pressure HRSG where steam from a single pressure HRSG flows at high pressure into a steam turbine, some steam is extracted from the steam turbine for use in the site process (cogen) and the remainder of the steam continues to expand through the steam turbine to the condenser conditions (combined cycle)
- GT + 2P ST – similar to the above single pressure case except that the HRSG is a two pressure unit with the intermediate level steam conditions (IP) set at the site steam conditions. Steam flows to the site at the intermediate steam conditions and steam is either added to the steam turbine at the IP level if the site steam requirement is low or extracted from the steam turbine at the IP level if site steam requirements exceed the HRSG IP steam generation capability.

High pressure steam parameters

In each case the user must identify the high pressure steam conditions at the entrance to the steam turbine. These steam conditions need to be higher than the site steam conditions.

8.23 Steam turbine condenser cooling configuration

This dialog box applies if a steam turbine arrangement with a condenser is selected. This arrangement hence only applies if the "GT + ST cogen/CC" configuration is selected in the Admin/configuration dialog and also either a "GT + 1P ST" or "GT+2P ST" arrangement is selected in the Gas Turbine plus steam turbine configuration dialog (Section 8.2).



Three selections are provided for the condenser cooling configuration, which impacts upon the condenser pressure for the steam turbine and hence its output.

- Once through cooling
- Evaporative cooling tower
- Air cooled condenser

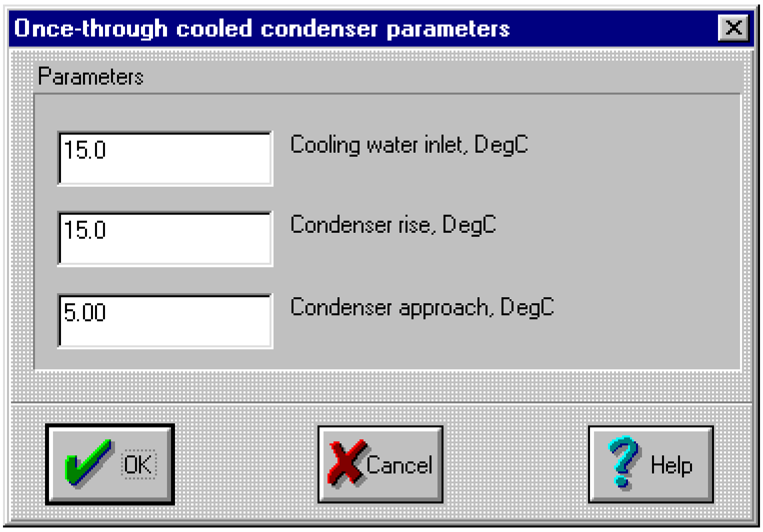
Whilst the cheapest option, and usually providing the maximum steam turbine output, Once through cooling is becoming increasingly difficult to implement because of thermal pollution of the receiving waters for the heated cooling water.

Evaporative cooling towers consume water, which should be considered, but are the most common modern arrangement for cooling a steam turbine condenser.

Air cooled condensers are selected when insufficient water is available for an evaporative cooling tower. The economic selection of the air cooled condenser usually results in a higher back pressure on the steam turbine and hence reduced output. Cost of the air cooled condenser itself can also be higher than an evaporative cooling tower option.

8.24 Once through cooled condenser parameters

These parameters apply when once through cooling is selected as the steam turbine condenser cooling configuration under Section 8.23.



Cooling water inlet
Temperature of the cooling water prior to entry into the cooling system.

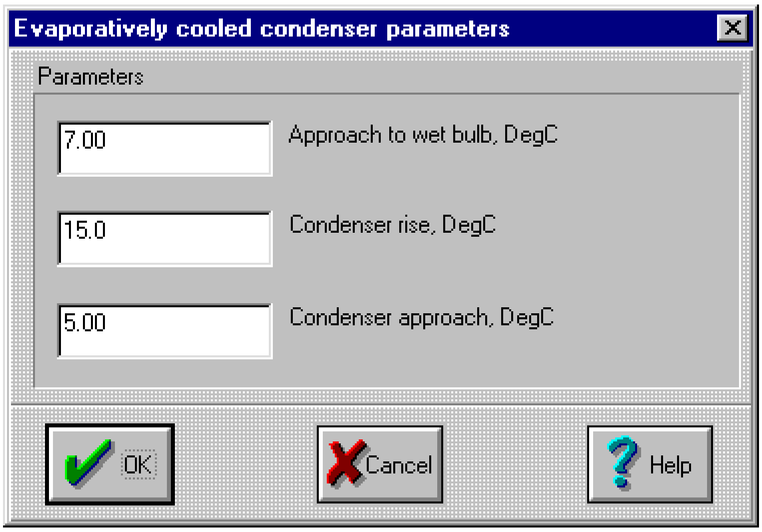
Condenser rise
The temperature increase of the cooling water across the condenser. A smaller value reduces the thermal pollution of the environment and increases the performance of the steam turbine but adds significantly to the cost and size of the condenser.

Many units have been historically constructed with cooling water rise in the 7 to 10°C range (15 to 20°F).

Condenser approach
The condenser approach is the temperature difference between the cooling water temperature leaving the condenser (ie the Cooling water inlet temperature + the condenser rise), and the saturation temperature on the steam-side of the condenser. 5°C (9°F) is a typical value.

8.25 Evaporatively cooled condenser parameters

These parameters apply when evaporative cooling is selected as the steam turbine condenser cooling configuration under Section 8.23.



Approach to wet bulb
This is a measure of the effectiveness of the cooling tower in bringing the temperature of the cooling water down to the ambient wet bulb temperature, which is the theoretical limit.

Condenser rise
The temperature increase of the cooling water across the condenser. A smaller value increases the performance of the steam turbine but adds significantly to the cost and size of the condenser and also of the cooling tower as more water needs to be handled.

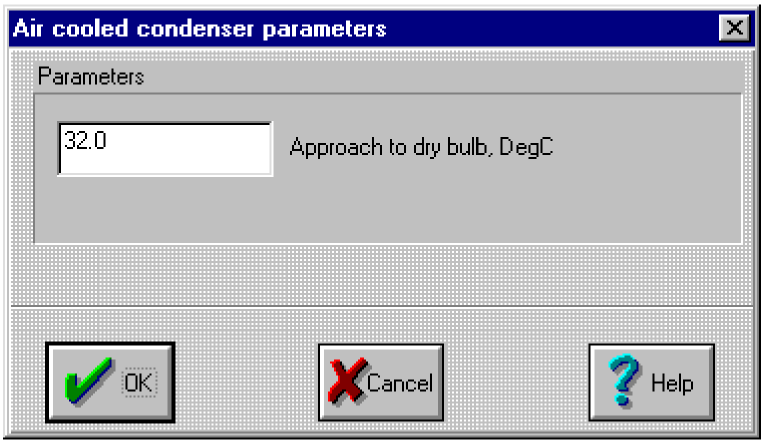
Many units have been historically constructed with cooling towers with cooling water rise in the 10 to 15°C (20 to 30°F) range.

Condenser approach

The condenser approach is the temperature difference between the cooling water temperature leaving the condenser (ie the Ambient wet bulb temperature + the approach to wet bulb + the condenser rise), and the saturation temperature on the steam-side of the condenser. 5°C (9°F) is a typical value.

8.26 Air cooled condenser parameters

These parameters apply when air cooled condenser cooling is selected as the steam turbine condenser cooling configuration under Section 8.23.

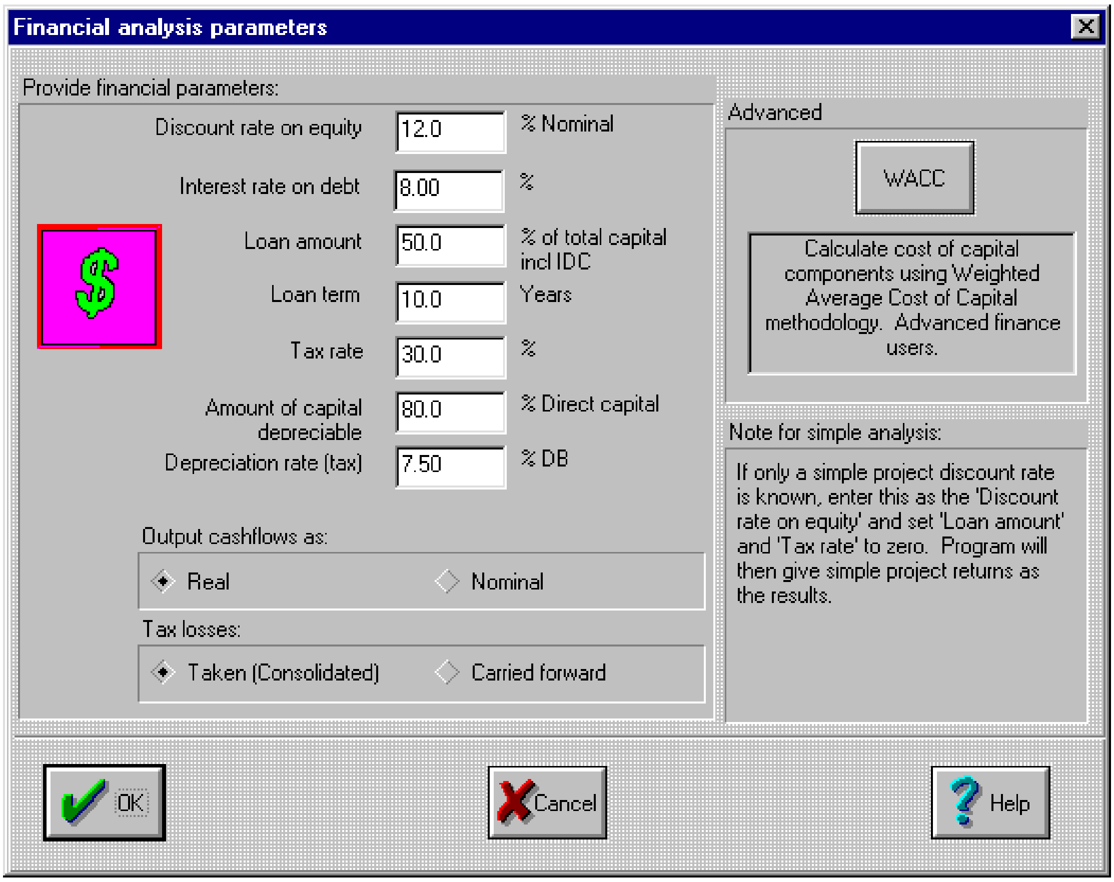


Approach to dry bulb

This is a measure of the effectiveness of the air cooled condenser in bringing the saturation temperature of the steam turbine exhaust down to the ambient dry bulb temperature, which is the theoretical limit.

The default value of 32°C (≅ 60°F) is not uncommon.

8.27 Financial parameters dialog



The Financial parameters dialog box is provided under the Financial | Parameters menu selection and prompts the user to provide the following information:

Discount rate on equity
The discount rate on equity as a <u>nominal</u> percentage. This is the user's internal rate of return including an inflation component.

Interest rate on debt
The interest rate charged on borrowed funds as a nominal percentage.

Loan amount
The loan amount as a percentage of total capital including interest during construction (IDC).

Loan term
The term of the loan in years. The default is the lesser value of the project life or 10 years.

Tax rate
The tax rate paid as a percentage. The default value is 30% (34% in USA).

Amount of capital depreciable
The amount of capital depreciable for tax purposes as a percentage of direct capital excluding IDC. The default value is 100%. Land value is not depreciable for tax purposes. Some improvements such as buildings may be depreciable but over a longer period than the plant itself.

Depreciation rate (tax)
The tax depreciation rate as a percentage of the declining balance (DB). This value is applied over all depreciable capital cost components except interest during construction (IDC). All components are taken to depreciate at the same rate. This is an approximation, as generally different elements have different depreciation rates and lives.

Note that with the removal of the previous accelerated depreciation regimes in Australia, unless the Australian Tax Office allows a scheduled rate for the plant involved, the declining balance rate might be 1.5 x 1/(effective life of the plant) as a percentage.

A separate depreciation profile applies in the USA. The profile adopted in the USA is:

Year	Percent of year 0 depreciable capital
1	5.0
2	9.5
3	8.55
4	7.7
5	6.93
6	6.23
7	5.9
8	5.9
9	5.91
10	5.9
11	5.91
12	5.9
13	5.91
14	5.9
15	5.91
16	2.95

Real or nominal selection
Displays cashflows in today's dollars or dollars of the day (escalated at the rates given in the Escalators section)

Tax losses selection
Tax losses are not uncommon in the early years of a capital intensive project. The program provides the following alternatives to assume that tax losses can be either

- "taken" (ie result in a negative tax cashflow in the project analysis in that year). This might be the appropriate alternative when the project is on-balance sheet and part of a larger, tax paying, business, or alternatively if off-balance sheet is wholly owned by a larger, tax paying, business and hence can be consolidated.

- "carried forward". If tax losses can not be taken in the year incurred then they might be carried forward until they can be offset against what would be otherwise taxable income.

Approximate handling of tax
The following assumptions are applied:

- Tax losses are credited in the Year applicable, or carried forward.
- Single tax rate, no investment allowances.
- Depreciation is calculated using the declining balance method for Australia, and according to the schedule for USA.
- Tax is paid one year in arrears (i.e.. provisional tax is ignored).
- Depreciation is first applied in Year 1. Year 1 tax for Year 0 flows is taken as IDC only. Operating cashflows for tax applied in Year 2 for Year 1 income/expenses etc.
- Start-up costs etc are not separated from capital costs.
- Spares costs are not separated from capital costs.
- Interconnection costs are separated from capital costs and amortised over 10 years.
- Simplified handling of capital gains or losses on the residual value are applied. Capital gains are not indexed (reduced) by CPI comparing the residual value with the indexed original cost less depreciation. Capital losses are also not indexed.
- Interest During Construction is capitalised, notwithstanding that this may not now be necessary.

Approximate handling of debt
The following assumptions are applied:

- On balance sheet. Working capital and debt service reserves are ignored.
- Single interest rate, no refinancing, no infrastructure bonds, swaps etc.
- Loan drawn down on the "capital cost day" (middle of Year 0).
- Loan repayments commence mid Year 1.
- Loan repayments, principal and interest in equal annual amounts (credit foncier type).

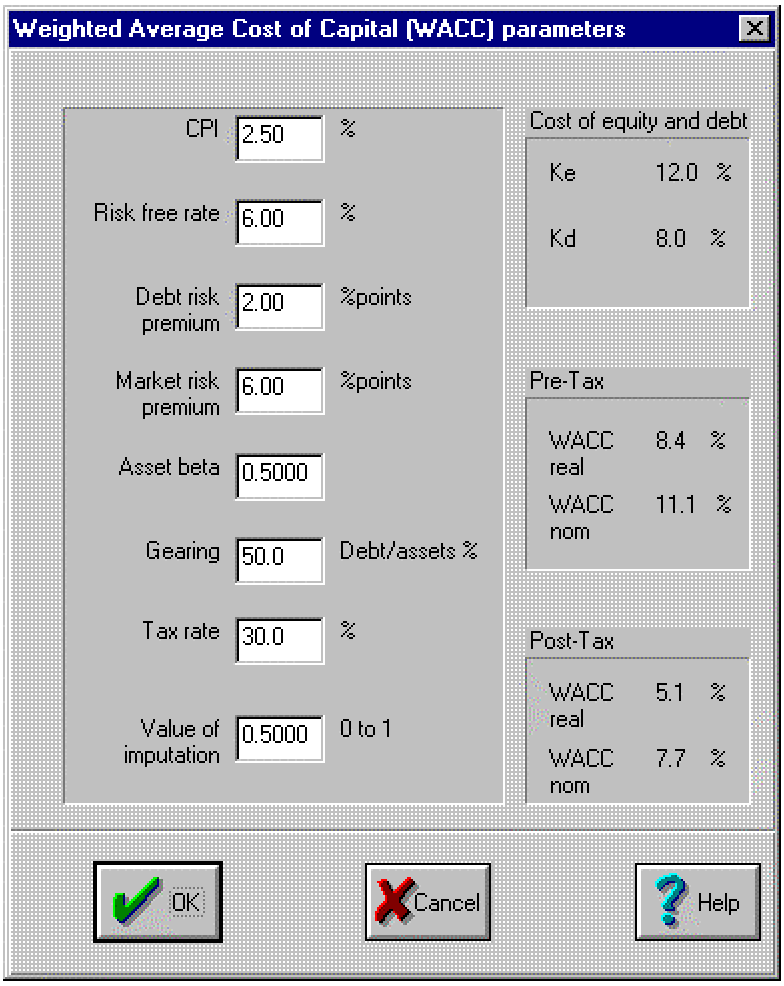
Advanced option – WACC button
The program has facility to calculate a weighted average cost of capital (WACC) and to apply the parameters from the WACC to the relevant parameters from this dialog box by pressing this button. This selection requires advanced financial interpretation.

Simplified analysis
In some circumstances the details of the financial structure appropriate for the project are not available to the user and only a 'Required discount rate on all projects' is provided by management. If this is the case then a simplified analysis consistent with such a simple discount rate can be generated by setting the 'Discount rate on equity' to management's discount rate and setting the 'Loan amount' and the 'Tax rate' both to zero.

This will also produce simple payback values in the program results that are based on the overall project costs rather than being based on equity only.

The user should ensure that the discount rate provided by management in these circumstances is in fact a nominal discount rate however, not a real discount rate.

8.28 Weighted average cost of capital (WACC) parameters dialog



The WACC parameters dialog is brought up from the financial parameters dialog (Section 8.27).

This dialog requires advanced financial interpretation. It is beyond the scope of the Ready Reckoner to discuss the advanced financial concepts applied.

The WACC is a common financial parameter that is sometimes used in the setting of a discount rate for a corporation.

The WACC is a weighted average cost of equity and debt funds (weighted according to their proportions in the balance sheet of the corporation).

In the context of the Cogeneration 'Ready Reckoner' analysis, particular note should be made that the WACC assumes a constant structure for the entity (tax, debt, equity etc) through its life whereas the Ready Reckoner analyses cash flows on a cash flow to equity basis after tax and after principal and interest payments on debt, none of which are taken to remain constant through the project's life.

The Ready Reckoner cashflow analysis picks up the changing depreciation tax shield, changing debt to equity ratio and that the debt term is usually less than the project life, whereas the WACC itself does not.

Nevertheless the WACC parameter might be of interest to some users. Further, the key parameters derived from this dialog box that are passed back to the financial parameters dialog - the cost of equity and debt (ke and kd) - are not subject to these limitations and the user may use this dialog as a convenient and somewhat rigorous means of setting these parameters.

The parameters requested are:
CPI
Projected inflation rate over the life of the project.

Risk free rate
The nominal implied yield on 10-year Government bonds is often applied for this parameter. This value is published daily in major newspapers.

Debt risk premium
Commercial borrowers have to pay a higher interest rate than the risk-free rate and the margin above the risk-free rate is largely set by the credit worthiness of the borrower.

Market risk premium
A parameter used in the Capital Asset Pricing Model (CAPM), a model for calculating the required rate of return on any risky investment, that is the weighted average return demanded by the market for all risky investments. The weighted return on listed securities is often used as a convenient proxy. 6% is a value that is commonly applied although there are grounds for believing that the actual premium now demanded is somewhat less.

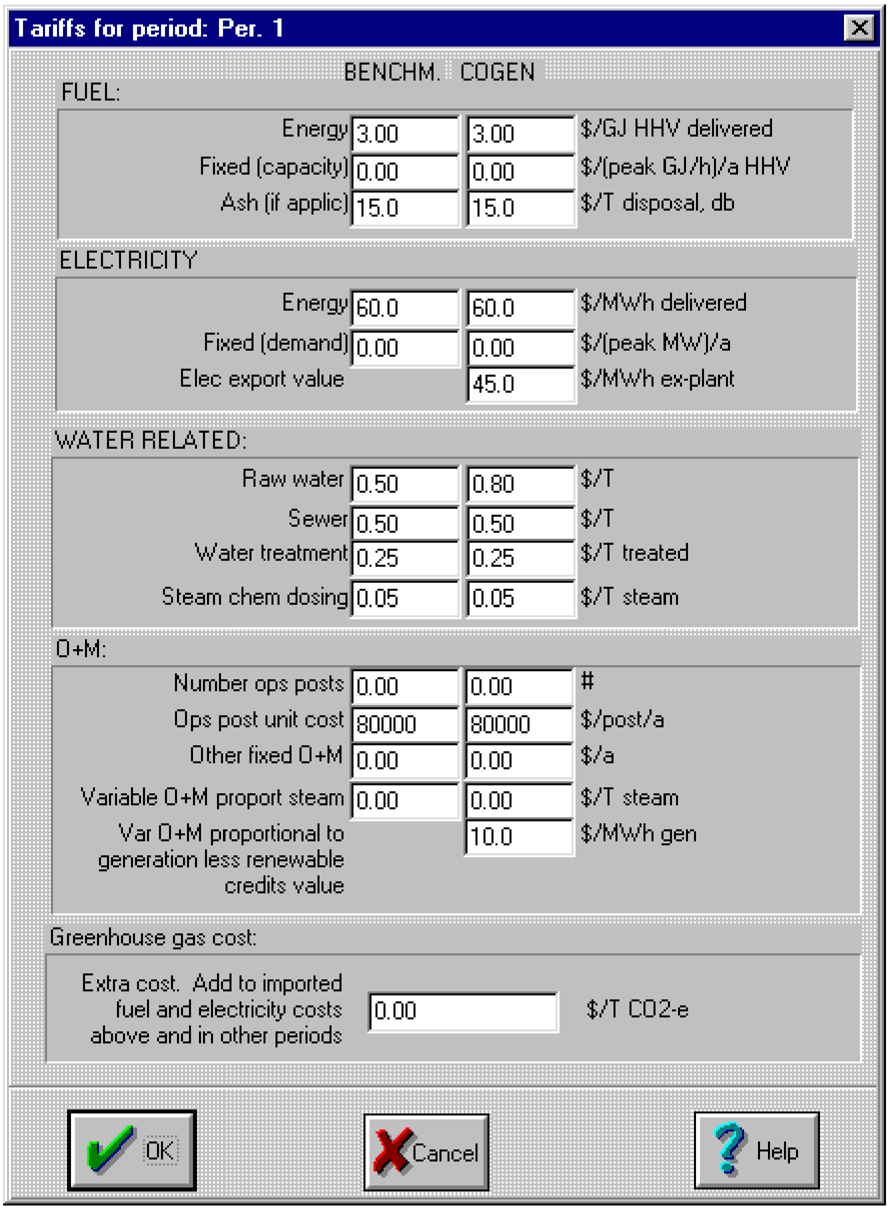
Asset beta
A measure of the variability of the return on the total investment of the proposed asset (the cogeneration plant investment) to the extent that this variability is correlated with variability of the returns on all other risky investment. This parameter is also from the CAPM.

Gearing
Same as the 'Loan amount' in Section 8.27. In theory the gearing level should be some adjusted level reflective of the average gearing level through the project's life (weighted by the discount rate in each year), but this is a time consuming, iterative procedure.

Tax rate
Same as the 'Tax rate' in Section 8.27. In theory this should be adjusted by the 'tax wedge', which is the (usually reduced) tax rate payable by reason of such things as depreciation allowances.

Value of imputation
The value of imputation is a measure of the extent to which franking credits provided by tax paying corporations to shareholders along with dividends are of value to shareholders. The value should be between 0 (no value, or a classical tax regime that does not include dividend imputation (eg the USA)) and 1 (shareholders get full value for all franking credits distributed. This is a somewhat controversial area. The Victorian Office of the Regulator General selected a value of 0.5 in its review of the Victorian electricity distribution network's regulated returns.

8.29 Tariff dialog



A tariff is the conversion parameter to convert an engineering flow, for example GJ/year (mmbtu/year) for natural gas, to a cashflow element (k$/year).

Tariffs can be Real or Nominal, to produce Real or Nominal cashflow elements and hence should be entered in current dollar terms (the program will adjust future tariffs to suit, starting from these current tariffs).

The Tariff dialog box appears up to twelve times (once for each time period nominated, although the fixed cost elements only appear for the first) and prompts the user to provide the following information for both benchmark and cogen cases:

<u>**FUEL**</u>

Energy

The fuel energy tariff in $/GJ HHV delivered ($/mmbtu).

Fixed (capacity)

The fuel fixed capacity charge in $/(peak GJ/h) HHV ($/peak mmbtu/h). This parameter is often based on the fuel transportation charges (eg transmission and distribution charges in the case of natural gas).

For example if gas delivery charges were $0.30/GJ on the maximum hourly quantity of gas, then a value of $0.30 x 8760 = $2628/year might be appropriate.

Ash (if applic)

The fuel ash disposal charge in $/T disposal, dry basis (db).

<u>**ELECTRICITY**</u>

Energy

The electricity energy charge in $/MWh delivered.

Fixed (demand)
The electricity demand charge in \$/(peak MW). The default is \$0/(peak MW)/a. Note that this is an annual charge (\$/year) and not a unit charge (\$/MWh).

Electricity export value
The electricity export value in \$/MWh ex-plant. This parameter needs to be provided for the cogen case only.

<u>WATER RELATED</u>
Raw water
The raw water cost in \$/T of raw water.

Sewer
The sewer cost in \$/T of sewer waste.

Water treatment
The water treatment cost in \$/T of treated water.

Steam chem dosing
The steam chemical dosing cost in \$/T of steam.

<u>O + M</u>
Number ops posts
The number of operation posts, i.e. the personnel requirement. The default is 0.

Ops post unit cost
The operation post annual cost in \$/post/year.

This should include both direct and indirect costs and might, for example be approximately 1.4 to 1.6 times direct salary. Direct salary should include any penalty rates such as shift allowances. Average costs should consider all staff including management.

Other fixed O + M
Other fixed operation and maintenance costs in \$/year. The default is 0.

Variable O + M proport steam
The variable operation and maintenance cost proportional to steam usage in \$/T of steam. The default is 0.

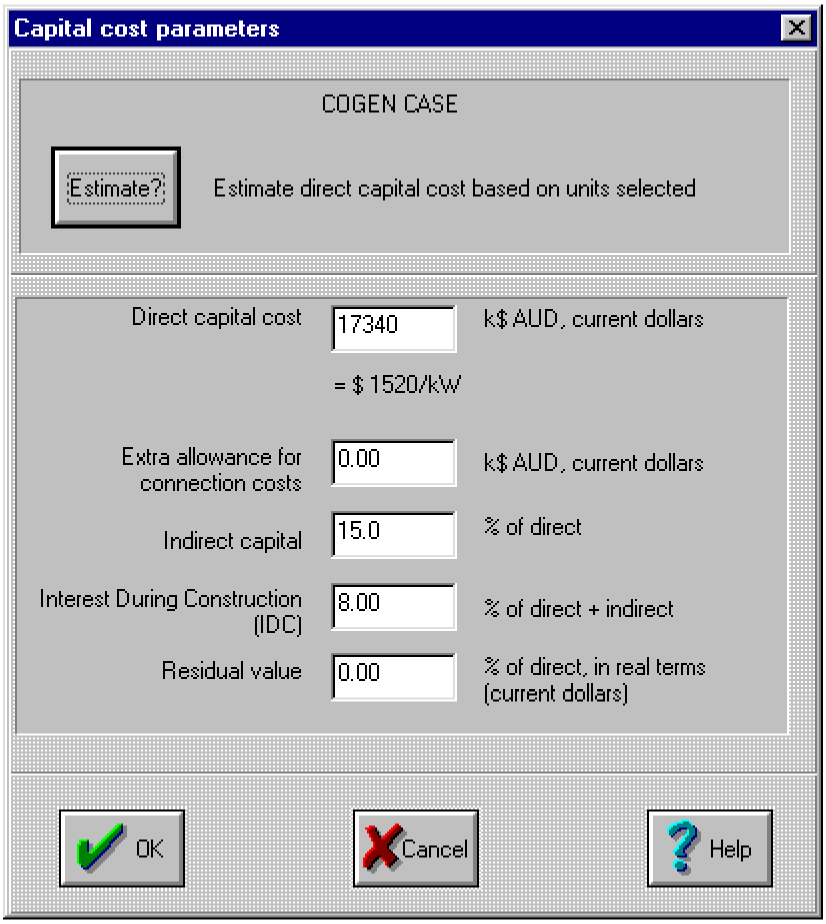
Variable O + M proportional to generation
The variable operation and maintenance cost proportional to electricity generation in \$/MWh generated. The default is \$10/MWh. This parameter to be provided for the cogen case only. A larger industrial gas turbine plant might have a cost of the order of \$2.50/MWh and a large aeroderivative gas turbine plant of the order of \$3.50/MWh. Suggest use of the order of \$1/MWh for the topping cycle cases.

If an additional value that is based on a '\$ per MWh' basis can be ascribed to the generated output, such as the value of Australian Renewable Energy Certificates (REC's), this can be deducted from the variable O&M.

Greenhouse gas cost
This allows the user to internalise the cost of emitting greenhouse gas, by entering a \$/T CO_2 emitted. Note that since the CO_2 emission rate used by the program includes an allowance for offset CO_2 attributable to the exported electricity and the reduction in imported electricity, care should be taken to ensure that the CO_2 cost included is not already built into the fuel and electricity cost parameters.

8.30 Capital cost data dialog

The Capital cost data dialog box appears once for the benchmark and once for the cogen case, and prompts the user to provide the following information:



Direct capital cost
The direct capital cost of the plant in k\$ AUD (USD), current dollars. Direct capital cost is taken to be equivalent to a turnkey price and includes:

- Plant, equipment, buildings, foundations etc.
- Contractor's engineering and project management
- Contractor's contingency and margin

For the cogen case, there is the option of the program estimating the direct capital cost based on the configuration selected via the "Estimate" button (which is not shown for the benchmark case).

For the topping cycle, no allowance is made in the in-built estimator for any new (high pressure) boilers that might be required. The costs for these can be considerable.

Extra allowance for connection costs
Allows a separate estimate for additional, project specific, infrastructure that might be required such as connection to, and reinforcement of, the electricity grid and the gas grid.

Indirect capital
Indirect capital as a percentage of the direct capital cost. Indirect capital includes:

- Owner's engineering.
- Owner's contingency.
- Spares.
- Start-up costs.

Interest during construction (IDC)

IDC as a percentage of the direct and indirect capital cost. IDC is the interest amount paid (or the cost of funds used) during the construction period for the funds deployed for progress payments. Costs are usually distributed across approximately a two year period in advance of the start of commercial operation. In the program, a method is used to place al the initial capital cost elements at a time in the middle of Year 0 (i.e.. 6 months before the first day of commercial operation). IDC is required to bring the capital cost elements together onto this date. In this program a simplified methodology is used which assumes a progress payments schedule and then discounts these payments to the value equivalent to the middle of Year 0. IDC is the excess over the simple sum of the capital cost components of this equivalent payment.

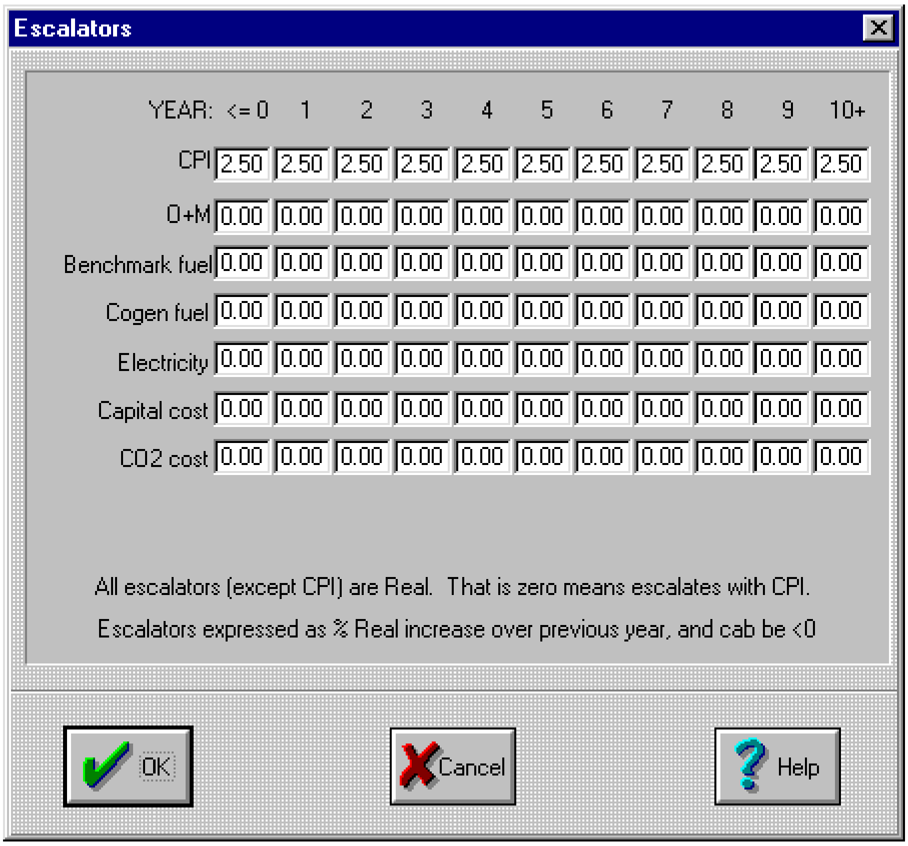
Residual value

The user can assign a residual value as a percentage in real terms of the initial direct capital cost. Residual salvage value is assumed to be received on the last day of commercial operation of the project.

The default value is 0%.

8.31 Escalators dialog

The Escalators dialog box prompts the user to provide the escalator information to allow the program to calculate a future tariff from a current tariff:



Since tariffs are entered in "today's" dollars, and the time from today to the middle of Year Zero (the date 6 months before commercial operation commences) will in general value be greater than zero years for a typical project, an allowance must be made for escalations in this period if the user desires cashflows in nominal dollars or if relative (real) tariffs between cost elements are expected to change in the intervening period.

The values entered in by the user are % changes from the previous year. For example, if "2" is entered for Year 1 then the escalator for Year 1 is to be 1.02 x the escalator for Year 0.

CPI
The consumer price index escalator for years <=0 up to years 10+.

O + M
The operation and maintenance cost escalator for years <=0 up to years 10+, expressed as a percentage real increase over the previous year. Default value is 0%.

Benchmark fuel
The benchmark fuel cost escalator for years <=0 up to years 10+, expressed as a percentage real increase over the previous year. Default value is 0%.

Cogen fuel
The cogen fuel cost escalator for years <=0 up to years 10+, expressed as a percentage real increase over the previous year. Default value is 0%. This might be different from the benchmark fuel escalator, particularly is different fuels are used.

Electricity
The electricity cost escalator for years <=0 up to years 10+, expressed as a percentage real increase over the previous year. Default value is 0%.

Capital cost
The capital cost escalator for years <=0 up to years 10+, expressed as a percentage real increase over the previous year. Default value is 0%.

CO_2 cost
Allows the cost of CO_2 emissions entered in the tariffs dialog (Section 8.29) to be varied over the project's life.

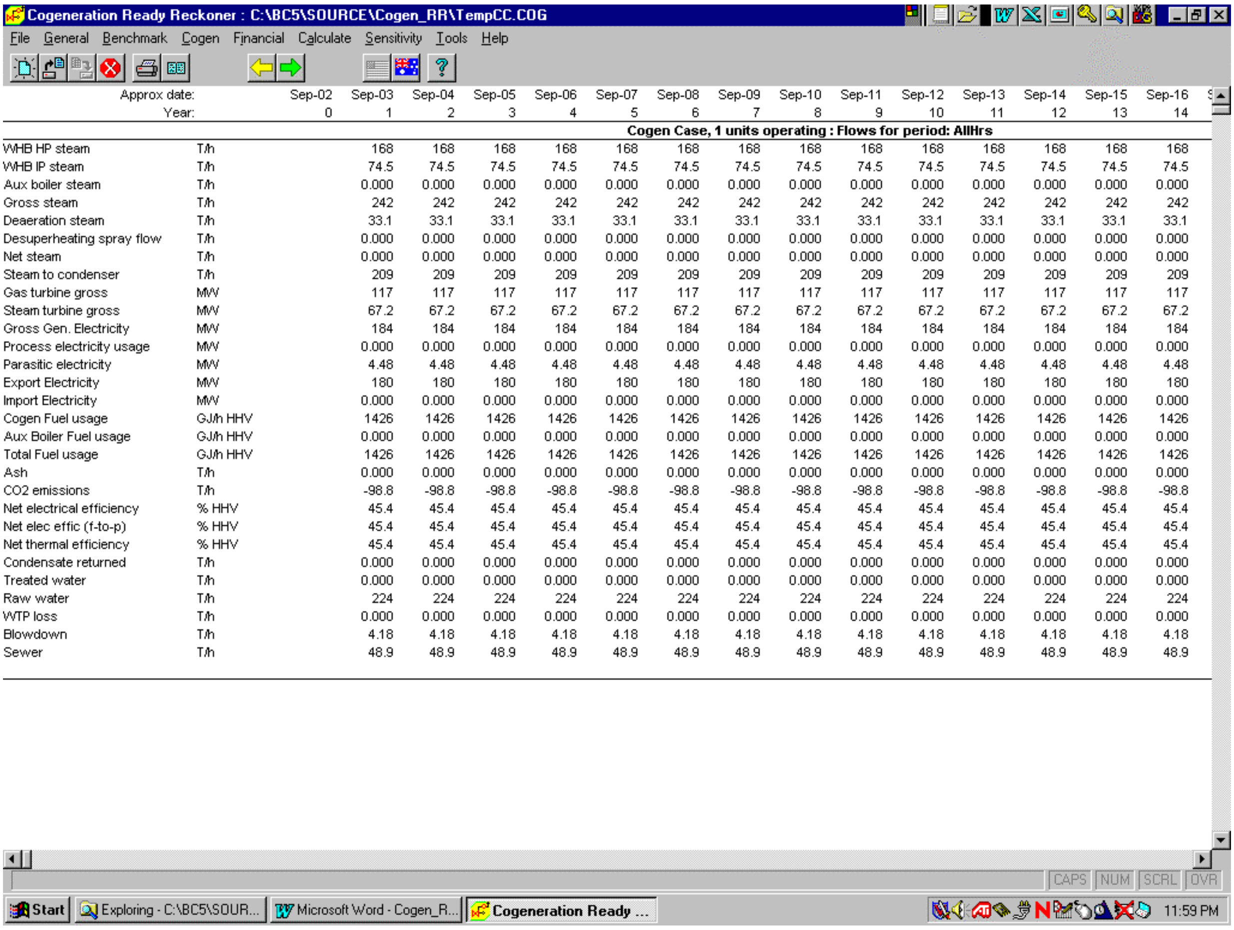
9. Outputs

9.1 General

This section provides some assistance with interpreting the outputs from the program.

After the data has been entered via the dialog boxes described in Section 8, the results of the analysis can be accessed via the Calculate menu option.

9.2 Hourly flows



	Approx date:	Sep-02	Sep-03	Sep-04	Sep-05	Sep-06	Sep-07	Sep-08	Sep-09	Sep-10	Sep-11	Sep-12	Sep-13	Sep-14	Sep-15	Sep-16
	Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Cogen Case, 1 units operating : Flows for period: AllHrs																
WHB HP steam	T/h		168	168	168	168	168	168	168	168	168	168	168	168	168	168
WHB IP steam	T/h		74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5
Aux boiler steam	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gross steam	T/h		242	242	242	242	242	242	242	242	242	242	242	242	242	242
Deaeration steam	T/h		33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1
Desuperheating spray flow	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Net steam	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Steam to condenser	T/h		209	209	209	209	209	209	209	209	209	209	209	209	209	209
Gas turbine gross	MW		117	117	117	117	117	117	117	117	117	117	117	117	117	117
Steam turbine gross	MW		67.2	67.2	67.2	67.2	67.2	67.2	67.2	67.2	67.2	67.2	67.2	67.2	67.2	67.2
Gross Gen. Electricity	MW		184	184	184	184	184	184	184	184	184	184	184	184	184	184
Process electricity usage	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Parasitic electricity	MW		4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48	4.48
Export Electricity	MW		180	180	180	180	180	180	180	180	180	180	180	180	180	180
Import Electricity	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cogen Fuel usage	GJ/h HHV		1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426
Aux Boiler Fuel usage	GJ/h HHV		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Fuel usage	GJ/h HHV		1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426	1426
Ash	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO2 emissions	T/h		-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8	-98.8
Net electrical efficiency	% HHV		45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4
Net elec effic (f-to-p)	% HHV		45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4
Net thermal efficiency	% HHV		45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4
Condensate returned	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Treated water	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Raw water	T/h		224	224	224	224	224	224	224	224	224	224	224	224	224	224
WTP loss	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Blowdown	T/h		4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18
Sewer	T/h		48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9	48.9

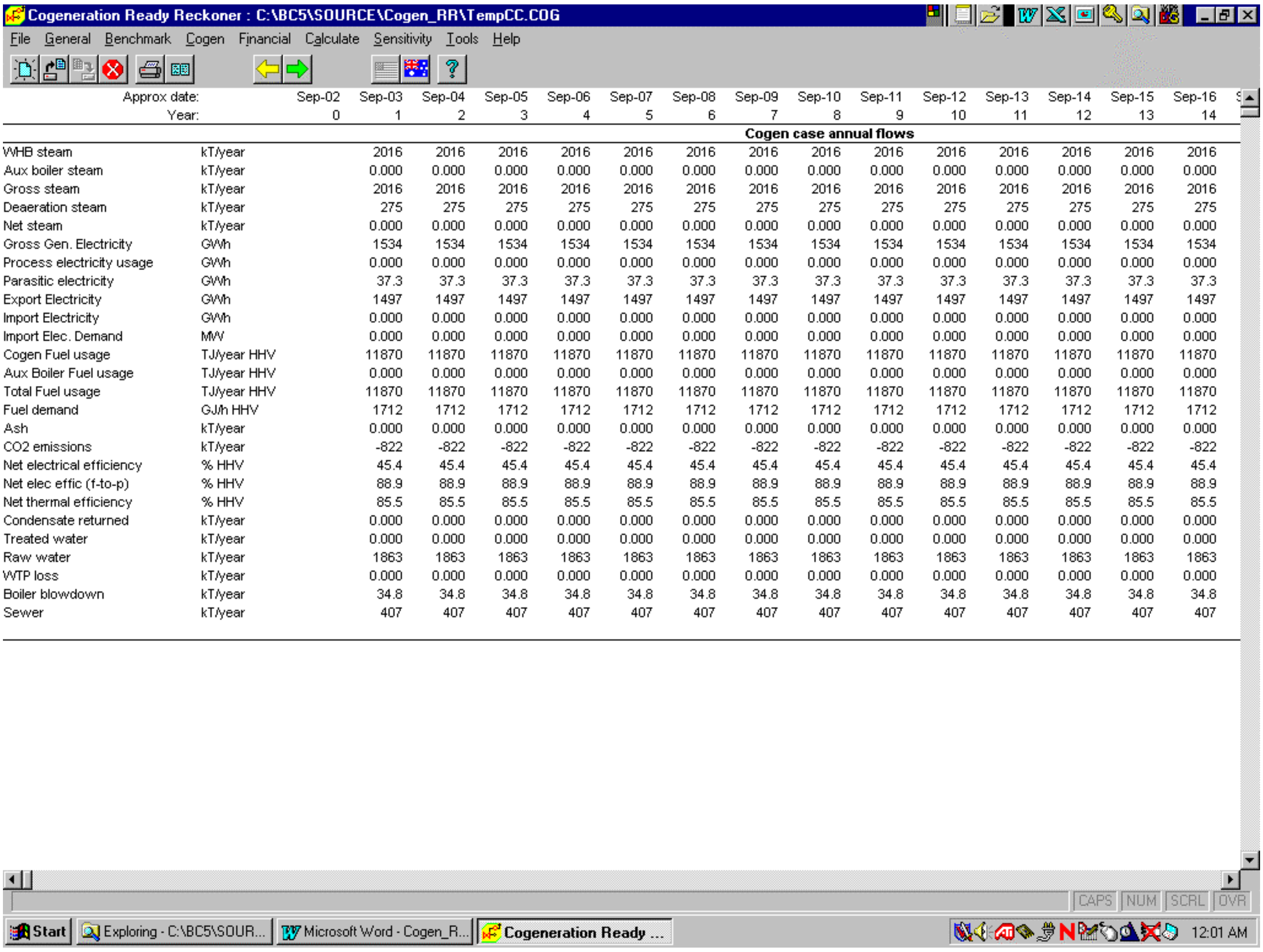
Hourly flows can be viewed for the Benchmark case, Cogeneration case with N (ie all) units operating and the cogeneration case with N-1 cogen units operating. The parameters that are shown vary slightly depending upon whether the Benchmark or Cogeneration case is being displayed and depending on what configuration is selected.

A table is provided for each of the operating periods selected. A description of the relevant case displayed is provided in the header line of the table.

The approximate date displayed in each column is based on the computer's system clock that the program is operating on, plus the number of years from today to the middle of year 0 entered in the Administration/configuration dialog (Section 8.2).

Note that the CO_2 emissions are those for the plant itself plus emissions attributable to imported electricity and also a deduction for emissions offsets attributable to exported electricity.

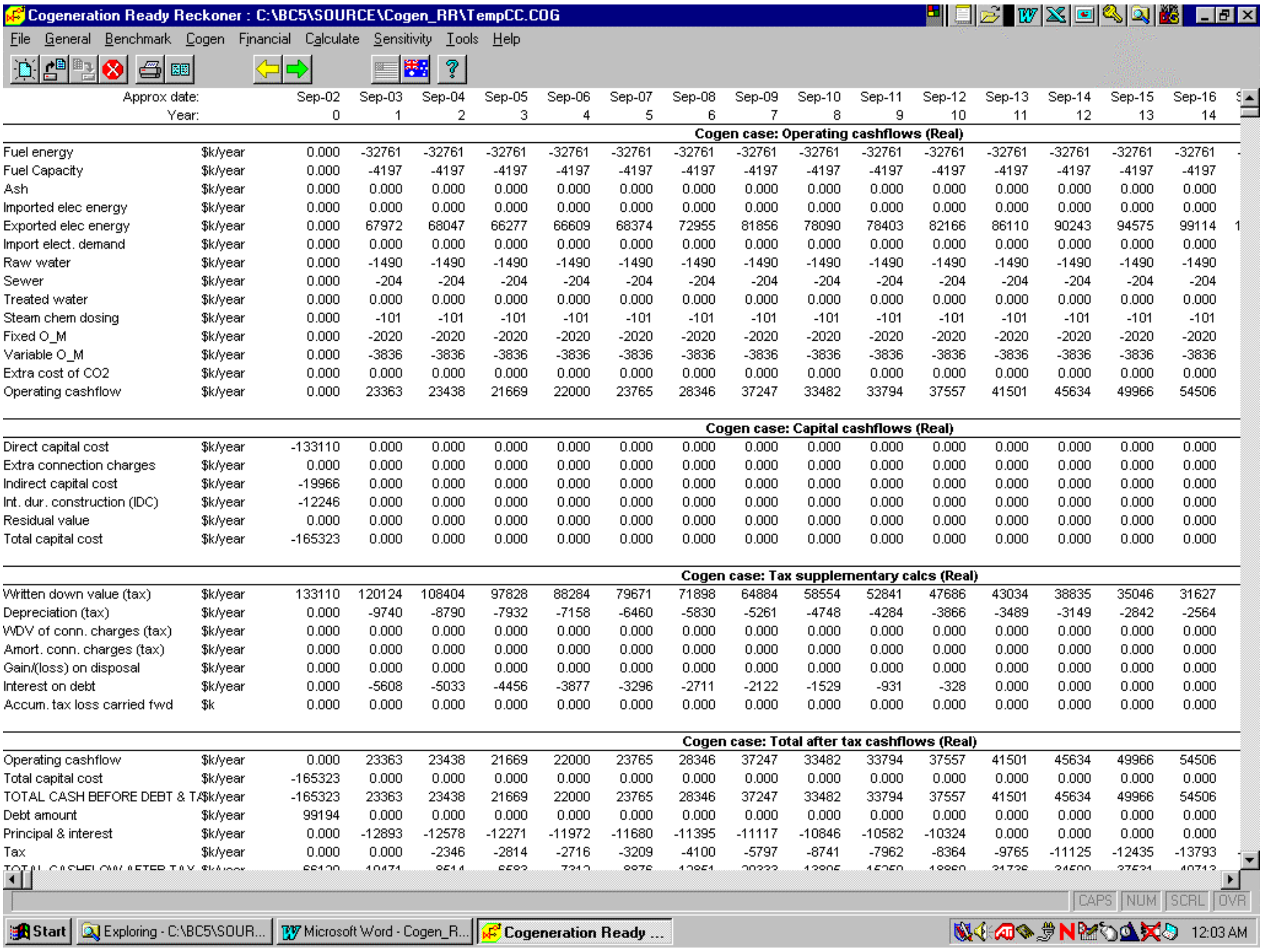
9.3 Annual flows



Approx date:		Sep-02	Sep-03	Sep-04	Sep-05	Sep-06	Sep-07	Sep-08	Sep-09	Sep-10	Sep-11	Sep-12	Sep-13	Sep-14	Sep-15	Sep-16
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Cogen case annual flows																
WHB steam	kT/year		2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
Aux boiler steam	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gross steam	kT/year		2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
Deaeration steam	kT/year		275	275	275	275	275	275	275	275	275	275	275	275	275	275
Net steam	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gross Gen. Electricity	GWh		1534	1534	1534	1534	1534	1534	1534	1534	1534	1534	1534	1534	1534	1534
Process electricity usage	GWh		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Parasitic electricity	GWh		37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3	37.3
Export Electricity	GWh		1497	1497	1497	1497	1497	1497	1497	1497	1497	1497	1497	1497	1497	1497
Import Electricity	GWh		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Import Elec. Demand	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cogen Fuel usage	TJ/year HHV		11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870
Aux Boiler Fuel usage	TJ/year HHV		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Fuel usage	TJ/year HHV		11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870	11870
Fuel demand	GJ/h HHV		1712	1712	1712	1712	1712	1712	1712	1712	1712	1712	1712	1712	1712	1712
Ash	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO2 emissions	kT/year		-822	-822	-822	-822	-822	-822	-822	-822	-822	-822	-822	-822	-822	-822
Net electrical efficiency	% HHV		45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4	45.4
Net elec effic (f-to-p)	% HHV		88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9	88.9
Net thermal efficiency	% HHV		85.5	85.5	85.5	85.5	85.5	85.5	85.5	85.5	85.5	85.5	85.5	85.5	85.5	85.5
Condensate returned	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Treated water	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Raw water	kT/year		1863	1863	1863	1863	1863	1863	1863	1863	1863	1863	1863	1863	1863	1863
WTP loss	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Boiler blowdown	kT/year		34.8	34.8	34.8	34.8	34.8	34.8	34.8	34.8	34.8	34.8	34.8	34.8	34.8	34.8
Sewer	kT/year		407	407	407	407	407	407	407	407	407	407	407	407	407	407

Annual flows provide the total annual engineering units parameters that the cashflows are based upon. They are derived from the hourly flows by considering the number of hours in the year represented by each of the periods, the number of process hours in the year entered in the Operational Hours Data dialog (Section 8.5), and in the cogeneration case the proportion of hours in the N operating and N-1 operating unit cases.

9.4 Benchmark and cogen case cashflows



	Approx date:	Sep-02	Sep-03	Sep-04	Sep-05	Sep-06	Sep-07	Sep-08	Sep-09	Sep-10	Sep-11	Sep-12	Sep-13	Sep-14	Sep-15	Sep-16
	Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Cogen case: Operating cashflows (Real)																
Fuel energy	$k/year	0.000	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761
Fuel Capacity	$k/year	0.000	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197
Ash	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Imported elec energy	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Exported elec energy	$k/year	0.000	67972	68047	66277	66609	68374	72955	81856	78090	78403	82166	86110	90243	94575	99114
Import elect. demand	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Raw water	$k/year	0.000	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490
Sewer	$k/year	0.000	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204
Treated water	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Steam chem dosing	$k/year	0.000	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101
Fixed O_M	$k/year	0.000	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020
Variable O_M	$k/year	0.000	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836
Extra cost of CO2	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Operating cashflow	$k/year	0.000	23363	23438	21669	22000	23765	28346	37247	33482	33794	37557	41501	45634	49966	54506
Cogen case: Capital cashflows (Real)																
Direct capital cost	$k/year	-133110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Extra connection charges	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Indirect capital cost	$k/year	-19966	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Int. dur. construction (IDC)	$k/year	-12246	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Residual value	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total capital cost	$k/year	-165323	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cogen case: Tax supplementary calcs (Real)																
Written down value (tax)	$k/year	133110	120124	108404	97828	88284	79671	71898	64884	58554	52841	47686	43034	38835	35046	31627
Depreciation (tax)	$k/year	0.000	-9740	-8790	-7932	-7158	-6460	-5830	-5261	-4748	-4284	-3866	-3489	-3149	-2842	-2564
WDV of conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Amort. conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gain/(loss) on disposal	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Interest on debt	$k/year	0.000	-5608	-5033	-4456	-3877	-3296	-2711	-2122	-1529	-931	-328	0.000	0.000	0.000	0.000
Accum. tax loss carried fwd	$k	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cogen case: Total after tax cashflows (Real)																
Operating cashflow	$k/year	0.000	23363	23438	21669	22000	23765	28346	37247	33482	33794	37557	41501	45634	49966	54506
Total capital cost	$k/year	-165323	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CASH BEFORE DEBT & TA	$k/year	-165323	23363	23438	21669	22000	23765	28346	37247	33482	33794	37557	41501	45634	49966	54506
Debt amount	$k/year	99194	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Principal & interest	$k/year	0.000	-12893	-12578	-12271	-11972	-11680	-11395	-11117	-10846	-10582	-10324	0.000	0.000	0.000	0.000
Tax	$k/year	0.000	0.000	-2346	-2814	-2716	-3209	-4100	-5797	-8741	-7962	-8364	-9765	-11125	-12435	-13793

The Benchmark and cogen case cashflows are derived by applying the tariffs, with appropriate escalation, to the annual flows.

The cashflows are displayed in four sections:

- Operating cashflows – which apply from Year 1 onwards. This is on an Earnings-before-interest,-tax,-depreciation-and-amortisation (EBITDA) cash basis.
- Capital cost cashflows – which are applied to Year 0
- Supplementary tax calculations – which show relevant parameters for the tax calculations, the balance of the carried forward tax loss account (if applicable) etc, and
- Total after tax to equity basis

INDUSTRY TOURISM RESOURCES
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9.5 Differential cash flow

Cogeneration Ready Reckoner : C:\BC5\SOURCE\Cogen_RR\TempCC.COG

File General Benchmark Cogen Financial Calculate Sensitivity Tools Help

Approx date:		Sep-02	Sep-03	Sep-04	Sep-05	Sep-06	Sep-07	Sep-08	Sep-09	Sep-10	Sep-11	Sep-12	Sep-13	Sep-14	Sep-15	Sep-16
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Difference: Operating cashflows (Real)																
Fuel energy	$k/year	0.000	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761	-32761
Fuel Capacity	$k/year	0.000	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197	-4197
Ash	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Imported elec energy	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Exported elec energy	$k/year	0.000	67972	68047	66277	66609	68374	72955	81856	78090	78403	82166	86110	90243	94575	99114
Import elect. demand	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Raw water	$k/year	0.000	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490	-1490
Sewer	$k/year	0.000	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204	-204
Treated water	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Steam chem dosing	$k/year	0.000	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101	-101
Fixed O_M	$k/year	0.000	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020	-2020
Variable O_M	$k/year	0.000	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836	-3836
Extra cost of CO2	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Operating cashflow	$k/year	0.000	23363	23438	21669	22000	23765	28346	37247	33482	33794	37557	41501	45634	49966	54506
Difference: Capital cost cashflows (Real)																
Direct capital cost	$k/year	-133110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Extra connection charges	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Indirect capital cost	$k/year	-19966	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Int. dur. construction (IDC)	$k/year	-12246	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Residual value	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total capital cost	$k/year	-165323	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Difference: Supplementary cashflows (Real)																
Written down value (tax)	$k/year	133110	120124	108404	97828	88284	79671	71898	64884	58554	52841	47686	43034	38835	35046	31627
Depreciation (tax)	$k/year	0.000	-9740	-8790	-7932	-7158	-6460	-5830	-5261	-4748	-4284	-3866	-3489	-3149	-2842	-2564
WDV of conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Amort. conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gain/(loss) on disposal	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Interest on debt	$k/year	0.000	-5608	-5033	-4456	-3877	-3296	-2711	-2122	-1529	-931	-328	0.000	0.000	0.000	0.000
Accum. tax loss carried fwd	$k	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Difference: Total after tax cashflows (Real)																
Operating cashflow	$k/year	0.000	23363	23438	21669	22000	23765	28346	37247	33482	33794	37557	41501	45634	49966	54506
Total capital cost	$k/year	-165323	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CASH BEFORE DEBT & TA	$k/year	-165323	23363	23438	21669	22000	23765	28346	37247	33482	33794	37557	41501	45634	49966	54506
Debt amount	$k/year	99194	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Principal & interest	$k/year	0.000	-12893	-12578	-12271	-11972	-11680	-11395	-11117	-10846	-10582	-10324	0.000	0.000	0.000	0.000
Tax	$k/year	0.000	0.000	-2346	-2814	-2716	-3209	-4100	-5797	-8741	-7962	-8364	-9765	-11125	-12435	-13793

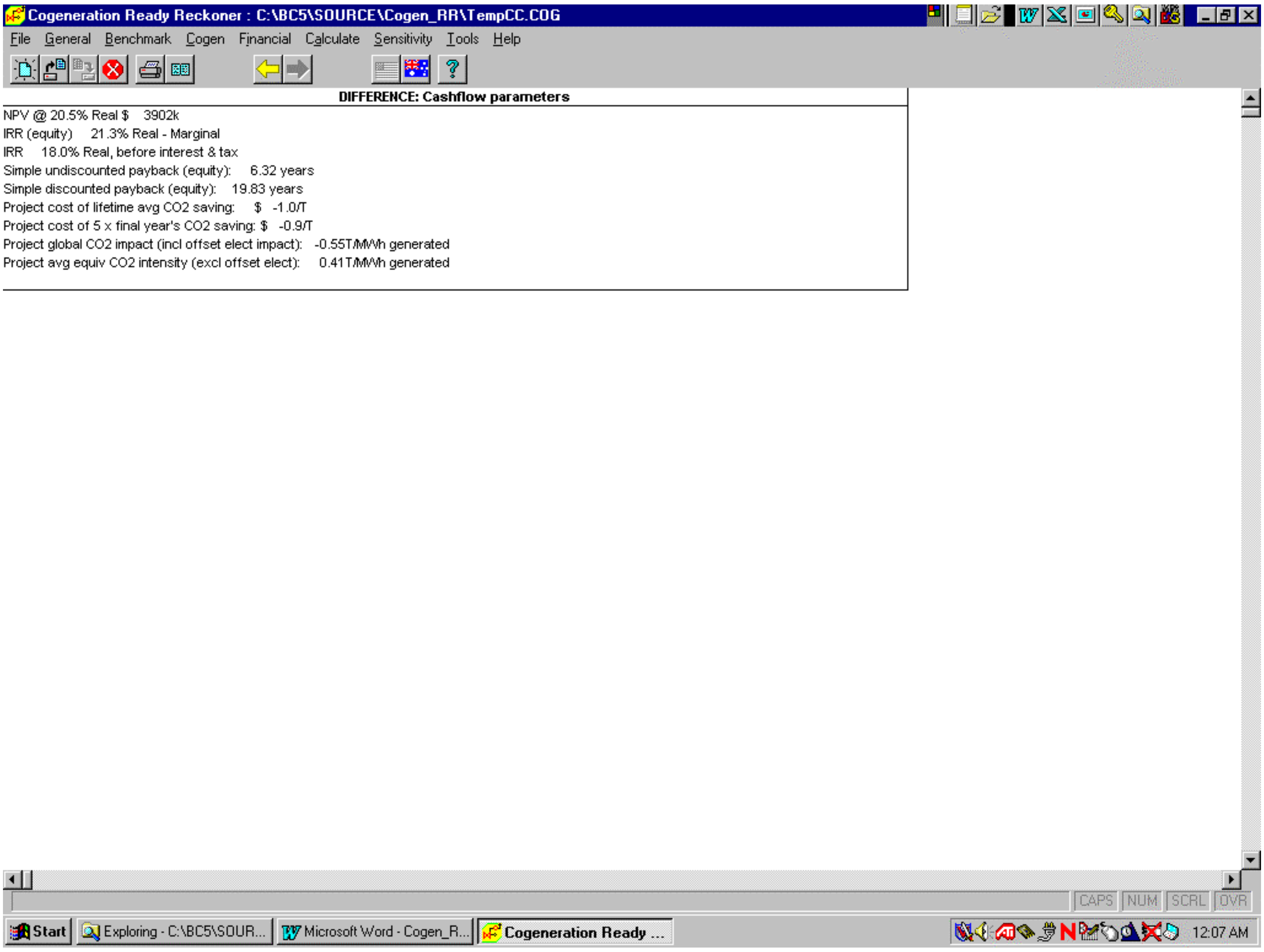
Start | Exploring - C:\BC5\SOUR... | Microsoft Word - Cogen_R... | Cogeneration Ready ... 12:04 AM

The differential cashflow is the cashflows resulting from the difference between the Cogen case and the Benchmark case cashflows.

With respect to the tax related cashflows, it should be noted that tax is calculated on the difference of the operating cashflows. This is different than would be the case if the cashflows were the difference in the tax payable in each case.

In the case where tax losses are “taken” in the year derived, this altered treatment makes no difference. The difference is apparent however in the case where tax losses are carried forward. Since carried forward tax losses are commonly applied where the project is off-balance sheet (eg a build-own-operate (BOO) type project), the tax treatment of the cogen operating company are more appropriately represented by this altered treatment.

9.6 NPV, IRR



The display of the NPV and IRR results are derived from the differential cashflows.

Where the program is unable to calculate an IRR it could be because no IRR exists.

The "Project cost of lifetime avg CO_2 saving" applies if the project saves CO_2 emissions yet has a negative NPV. This parameter indicates what the CO_2 saving subsidy would need to be to bring the project return up to 0 NPV.

The "Project cost of 5 x final year's CO_2 saving" parameter is calculated similarly but only applies the CO_2 emissions savings in the last five years of the project. These five years are intended as a proxy for the Kyoto reporting period of 2008 to 2012.

The "Project global CO_2 impact (incl offset elect impact)" is a parameter that measures the overall impact of the project on global CO_2 emissions. This includes allowing for CO_2 emissions attributable to steam and electricity import and export in both the Benchmark and Cogen cases. Cogen projects often result in a negative CO_2 impact, that is they result in an overall saving in greenhouse gas emissions.

The “Project global CO_2 impact (incl offset elect impact)” is:

$$\frac{\text{Cogen } CO_2 \text{ emissions} - \text{Benchmark } CO_2 \text{ emissions}}{\text{Net generated electricity}}$$

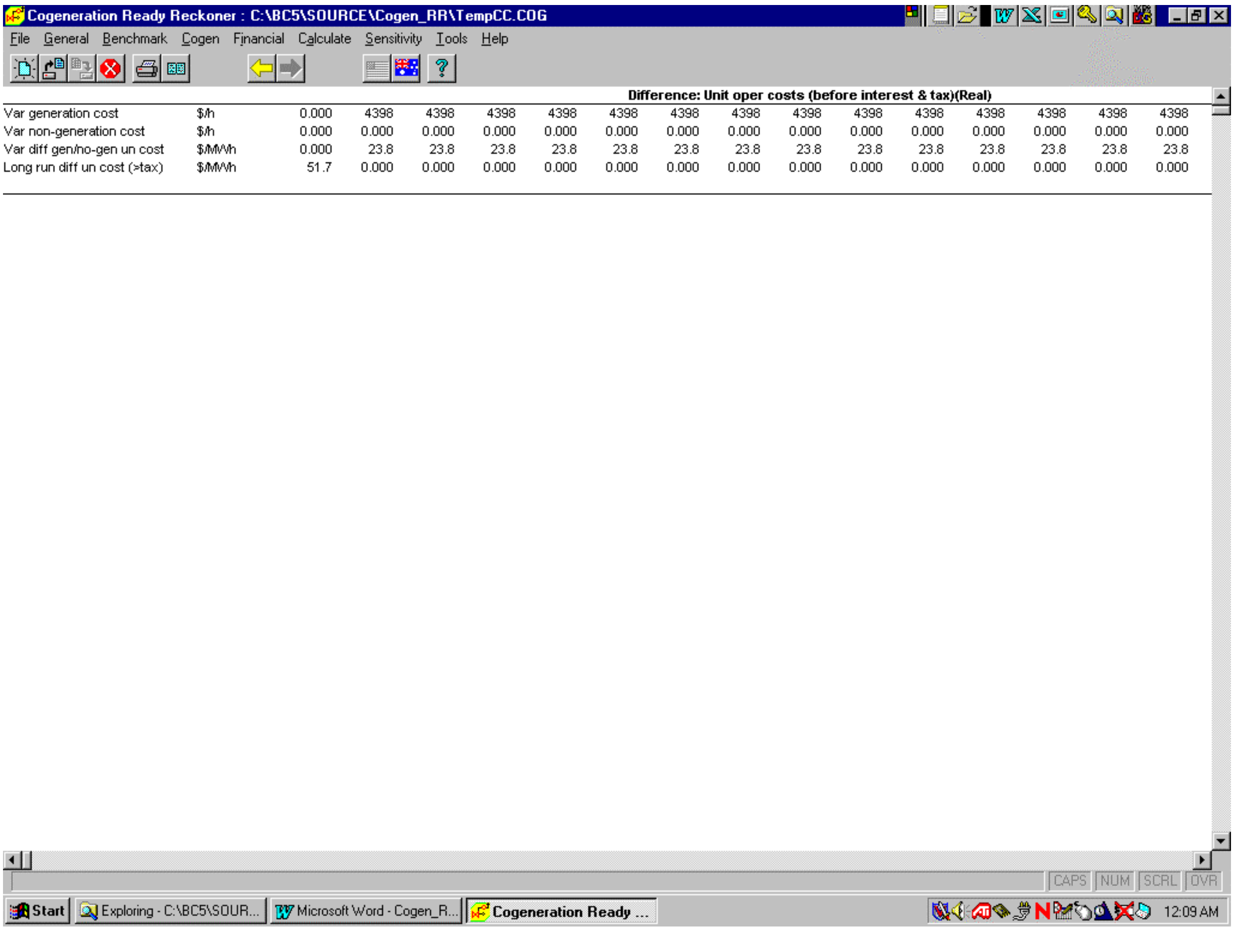
The “Project global CO_2 impact (excl offset elect)” is a related parameter that calculates the CO_2 intensity of the electricity generated by the cogen plant after allowing for the CO_2 that would have been produced on the site in the raising of steam in conventional boilers in the benchmark case.

The “Project global CO_2 impact (excl offset elect)” is:

$$\frac{\text{Cogen } CO_2 \text{ emissions excl import/export electricity} - \text{Benchmark } CO_2 \text{ excl import electricity emissions}}{\text{Net generated electricity}}$$

This parameter might be compared against the CO_2 intensity of other forms of generation plant such as coal (black coal is approximately 0.93 T/MWh).

9.7 Incremental operation



The incremental operation output provides guidance on the incremental cost of operation versus not operating and hence of whether it might be better to turn off the cogen plant in some periods (can be the case in off-peak times when purchased electricity is cheaper).

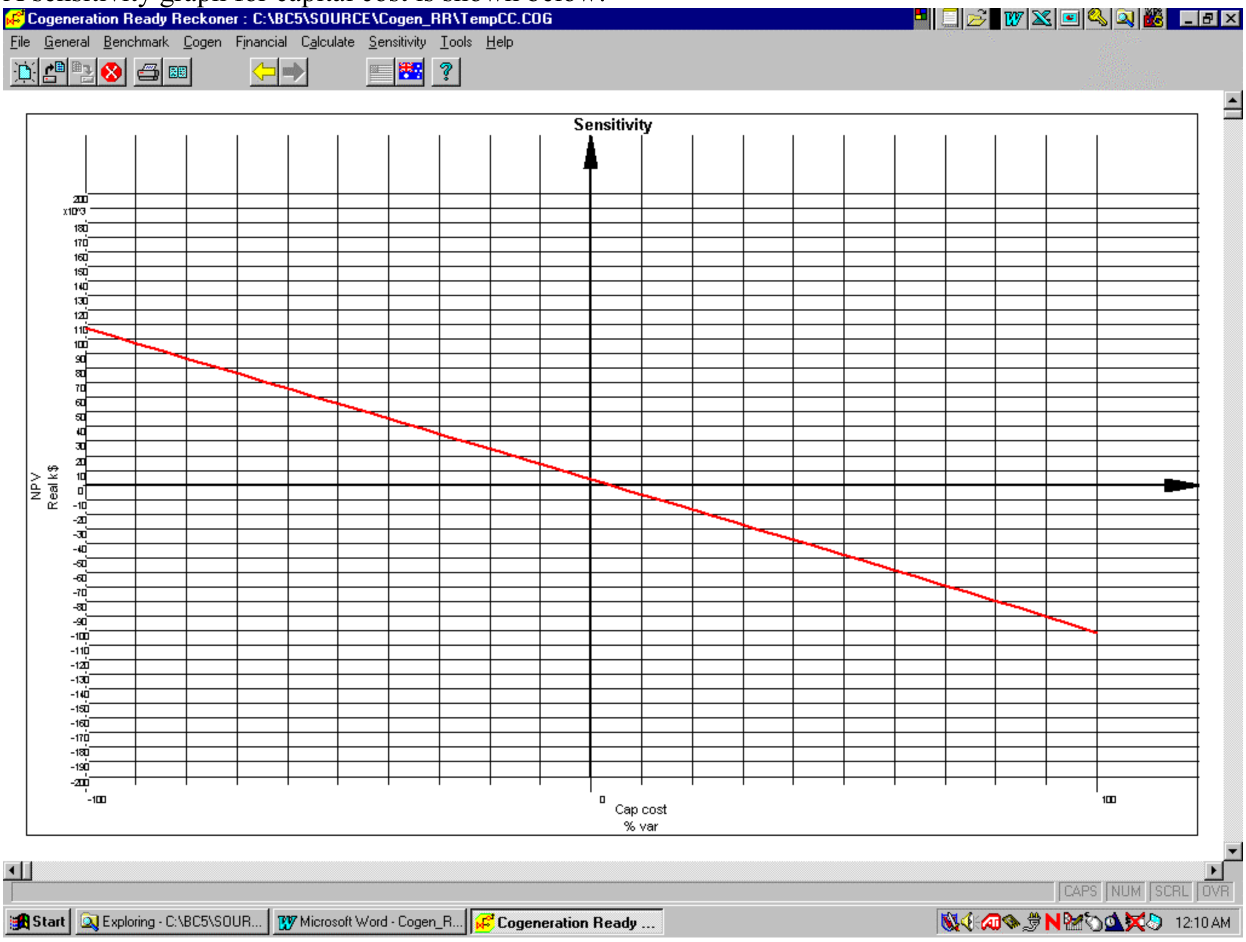
An indicative Long Run Marginal Cost for the electricity produced by the plant is also provided for information.

9.8 Sensitivities

Sensitivity graphs are provided for:

- Import electricity cost
- Export electricity value
- Fuel cost
- Capital cost, and discount rate

A sensitivity graph for capital cost is shown below:



Since each gradation along the x-axis of the graph represents 10% of the value entered into the program, in this case 10% of the capital cost, the graph shows that if the capital cost increased by 5% of the entered value for the project would fall to a zero NPV.

Such sensitivity analyses are with all other variables held constant.

The sensitivity graph for discount rate also shows the IRR in that the IRR is the discount rate at which the NPV is equal to zero.

10. Tools

10.1 Change country

These menu selections allow the user to change between Australia and USA. Different units (S.I. and imperial respectively), currencies (AUD and USD respectively) and default values are applied depending on the selection.

10.2 Gas turbine and recip engine databases

The tools section in particular provides means to update the gas turbine and reciprocating engine databases.

10.3 Defaults

Means are provided to alter a limited range of the defaults applied in the program. To go back to the embedded default values, delete or rename the "defaults.dat" file from the program working directory.

10.4 Dump to a CSV file

Key output data can be dumped to a CSV file.

A CSV file is a comma-separated-variable file (a set of ASCII values separated by commas) that can be readily read into a spreadsheet program such as Excel™ for post-processing.

11. Glossary

Term	Definition
Aeroderivative	Aeroderivative gas turbines originate from the aviation industry. They are lightweight, and have higher thermal efficiency and capital cost than industrial gas turbines. Maintenance costs can be higher. Exhaust gas temperatures are generally lower than industrial gas turbines. Performance decreases dramatically at high ambient temperatures.
ASL - above sea level	Elevation of site. Higher elevations generally reduce GT and engine performance due to lower average air density
auxiliary boiler	Fuel fired boiler used to raise the site steam and / or hot water requirements.
back pressure steam turbine	A simple non-extraction (in this context) non-condensing steam turbine. High pressure steam is expanded through the back pressure steam turbine to generate electricity, and is exhausted at the required site steam conditions.
Benchmark	The existing, or “business-as-usual” operating regime.
boiler blowdown	Stream of water which is bled from the boiler drum or steam supply system to control the concentration of total solids and other contaminants in the boiler water.
boiler drum	Generally the steam drum of a boiler where the steam generated is separated from the circulating boiler water.
clean-as-new	New unit, no degradation.
condensate	Steam which has been condensed for return to the boiler.
deaerator	Used to preheat feedwater before entering the waste heat boiler, and to drive off non-condensable and potentially corrosive dissolved gases. Requires steam to provide the energy for heating. Not relevant to hot water case.
degradation	Deterioration in power output and/or heat rate of an engine or turbine under operating conditions due to, for example, inlet air contaminants, fuel contaminants and thermal stress. Continuous process occurring between overhauls.
Dialog box	An element of most Windows™ programs including this one consisting of a box, usually gray, with areas for the user to enter data (Edit boxes), make selections via various types of check boxes or radio buttons or list boxes etc, and/or buttons to select actions. Used for data input.
dump condenser	Excess steam from the waste heat boiler bypasses the steam turbine and goes directly to the condenser. Used to balance site load with steam generated.
dump stack & damper	Used to control flow and temperature of exhaust gas to bypass the waste heat boiler. Can also be used to isolate equipment in the exhaust gas stream when the equipment is out of service or requires maintenance. Used to balance steam generated with site load.
economizer	A counterflow heat exchanger for recovering energy from the exhaust gas. It increases the temperature of the water entering the boiler drum using otherwise wasted exhaust heat and hence increasing steam raising ability. Economizers are assumed on WHB’s in this analysis.
efficiency	Thermodynamically, the ratio of useful energy output to energy input into a process. Has many specific definitions and care needs to be taken that the meaning is clear. Refer to discussion in Basics section of this manual. See also Heat rate.
enthalpy	Measure of the heat content of a substance.
entropy	A measure of unavailable energy in a thermodynamic system.
feedwater	Total flow supplied to the boiler, sum of condensate and makeup.
FOB	Free-On-Board. A means of quoting the payment basis for equipment. FOB means the supplier pays for loading the equipment onto a truck/train/ship and the buyer is responsible for transportation and insurance from that point.
gas turbine	An engine operating on what is known as the Brayton cycle with continuous steady flow compression of air, constant pressure combustion and expansion of the compressed heated gases through an expansion turbine. Working fluid is usually air, fuels can be gaseous or premium liquid fuels such as distillate.
Heat rate	A form of expressing efficiency of an engine or turbine. The fuel heating value consumed per unit of useful output (usually electrical output). Common unit is kJ/kWh. To convert to efficiency divide by 3600 and invert.
Higher heating value (HHV)	And also higher calorific value etc - heating value of a fuel after correcting the combustion energy released back to ambient conditions and assuming that water content of combustion products is in liquid form.
Industrial	Heavier, more robust, and cheaper than aeroderivative gas turbines. Generally have lower thermal efficiency and higher exhaust gas temperatures than aeroderivative gas turbines.
Isentropic	Constant entropy, or effectively zero loss. Used in the context of steam turbine ability to convert steam energy into mechanical energy, as opposed to leaving the turbine as exhaust steam energy at the exhaust steam pressure.
ISO conditions	For gas turbine performance quotation – conditions stated in ISO 2314 - 15ºC, 0m ASL, 60% RH ambient conditions
Lower heating value (LHV)	And lower calorific value etc - heating value of a fuel after correcting the combustion energy released back to ambient conditions and assuming that water content of combustion products is in vapor form. Virtually always lower than HHV.
Makeup	Treated raw water which is added to the system to replace steam and water lost to site requirements,

Term	Definition
	blowdown, evaporation, sampling or venting.
Parasitics	The plant's internal power consumption and losses in raising the steam or electricity produced.
Reciprocating engine	An engine characterized by the movement of the pistons in the cylinders back and forth in a straight line driving a crankshaft to convert the work into rotary shaft work. Typical vehicle engine.
steam turbine	An engine in which a vaned wheel is made to revolve by the impingement of steam. Converts steam energy to mechanical energy.
superheater	A heat exchanger part of a boiler for increasing the temperature of saturated steam to superheated steam. Generally steam admitted into a steam turbine must be superheated (vis above the saturation temperature at that pressure).
supplementary fired	Additional gas firing for the waste heat boiler (between gas turbine and WHB) when the unfired exhaust gas is not sufficiently hot for raising the site steam requirements (temperature or steam mass flow). Can generally be done on gas turbine exhausts because sufficient oxygen remains in the exhaust. Not generally done on recip engine exhausts due to lower excess oxygen in exhaust.
Topping cycle	High pressure steam is raised in an auxiliary boiler and expanded through a back pressure steam turbine to the required site steam conditions.
turnkey	Installation to the point of readiness for operation, generally a single design & construct contract. Some owner's costs such as owner's engineering, spares, owner's start up labour & fuel, etc may be excluded and need to considered within the indirect costs or elsewhere.
waste heat boiler	A boiler which utilizes waste heat (such as gas turbine or reciprocating engine exhaust gas) for the production of steam or hot water.
WACC	Weighted average cost of capital – a discount rate that might be applied to a set of cashflows assuming 100% equity financing that is derived by considering a capital structure made up of equity and debt financing and weighting the cost of capital by the proportion of each. Usually provides adjustments for the tax deductibility of interest payments on debt and often for the value of imputation credits provided with dividend payments on equity.

Appendix A Sample output

The following output is based on a hypothetical plant supplying a 10T/h steam load (at 10 barg, saturated) and a host base load of 3MW. The comparison is shown against a 5MW gas turbine. Most of the parameters may remain as the default parameters in this analysis.

Cogeneration Ready-Reckoner - Version 3.1

Evaluating a cogeneration application in my company

A Ready Reckoner for industry financial and technical management

The user acknowledges that the Commonwealth of Australia, Australian EcoGeneration Association and Sinclair Knight Merz Pty Ltd (together the 'Providers') provide the Cogeneration Ready Reckoner software on the following basis:

* That the Program is not intended to be a final or authoritative assessment but rather a preliminary assessment of potential cogeneration opportunities
* That the software is not intended as a tool for basing final investment decisions upon, and in all cases the user must conduct sufficient additional analyses and obtain appropriate professional advice before proceeding with any investment decision
* That the Providers do not, and cannot in any way supervise, edit or control the content of any information or data accessed through the service and shall not be held responsible in any way for any content or information accessed or input into this service
* That the Providers do not warrant that printed or displayed outputs from the program are accurate assessments of the viability of any particular course of action
* That the Providers are released from and indemnified, along with its servants and agents against all actions, claims and demands which may be instituted against the Providers arising out of the use of this program or of any other person for whose acts or omissions the user is vicariously liable, and
* That the Providers do not warrant that the software is free from 'bugs' or defects

Title: Example analysis

Input parameters

Cogen type............................Gas turbine
Gas turbine type.......................Industrial
Thermal load type.................Steam
Benchmark fuel name............Natural gas
Cogen case fuel.....................Natural gas

User parameters

Time today to Mid Year 0	Years	0.000	Cond. temperature	Deg C	70.0
Site steam pressure	kPag	1000	Make-up water temp	Deg C	15.0
Site steam temperature	Deg C	183	Deaerator temperature	Deg C	105
Number of cogen units	#	1.00	Process hours	hours/year	8760
Avg site ambient temp	Deg C	15.0	Cogen unit availability	%/unit	95.0
Site elevation	m	0.000	Imported elec efficiency	% delivered	35.0
Blowdown rate	%	2.00	Imported elec CO2 emissions	kg/MWh del	1010
WTP loss factor	% treat	10.0	Fired boiler efficiency	% HHV	80.0
Condensate return	%	50.0			

Operating hours parameters

		Per. 1
Perc hours this period	%	100
Hours this period	h/year	8760
Cogen scheduled on	True=1/False	1.00

Fuel parameters

		Bench: Natural gas	Cogen: Natural gas
Higher heating value	MJ/kg	51.2	51.2
Lower heating value	MJ/kg	46.2	46.2
Fuel carbon content	%m	72.7	72.7
Fuel ash content	%m	0.000	0.000

GT parameters

		Solar Taurus 60
Gross power	MW/unit	5.20
Unit parasitics	MW/unit	0.052
Heat rate, clean as new	kJ/kWh LHV	11852
Exhaust mass flow	T/h/unit	78.9
Exhaust temperature	Deg C	510
GT is industrial?	1=true/0=false	1.00
Unit reference cap cost	k$/unit FOB	3273

WHB parameters

Pinch point	Deg C	18.0	Approach	Deg C	25.0

Financial parameters

Risk free rate	% Nominal	6.00	Tax rate	%	30.0
Debt premium	% points	1.60	Amt dir. capital depreciable	%	100
Market risk premium	% points	6.00	Avg depreciation rate (tax)	% declining	7.50
Asset beta		0.600	Carry tax losses forward?	0=no, 1=yes	0.000
Gearing level	% Debt/assets	50.0	WACC pre-tax	% Real	8.84
Imputation value		0.500	WACC pre-tax	% Nominal	11.6
Equity disc. rate, after tax	% Nominal	13.2	WACC post-tax	% Real	5.46
Debt interest rate	%	7.60	WACC post-tax	% Nominal	8.10
Debt term	Years	10.0			

Tariffs (in current dollars)

		Bench.	**Cogen.**
Per. 1: Elec imp en	$/MWh	60.0	60.0
Per. 1: Elec exp en	$/MWh	0.000	45.0
Electricity demand	$/(peak MW)/y	0.000	0.000
Fuel energy	$/GJ HHV	3.00	3.00
Fuel demand (on max flow)	$/(pk GJ/h)/y	0.000	0.000
Ash disposal	$/T dry	0.000	0.000
Number staff	#	0.000	0.000
Staff unit cost	$k/post/y	80.0	80.0
Fixed O&M costs	$k/y	0.000	0.000
O&M costs re steam	$/Ts	0.000	0.000
O&M costs re generation	$/MWh gen	0.000	5.00
Electricity demand	$/(peak MW)/y	0.000	0.000
Raw water	$/T	0.800	0.800
Water treatment	$/T tr	0.250	0.250
Sewer	$/T	0.500	0.500
Steam chem dosing	$/Ts	0.050	0.050
Extra cost of CO2	$/T CO2	0.000	0.000

Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Escalators																							
CPI	% Nom	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	
O&M Escalator	% Real	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Benchmark fuel esc	% Real	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Cogen fuel	% Real	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Electricity escalator	% Real	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Capital cost escalator	% Real	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Extra CO2 cost escalator	% Real	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Benchmark: Flows for period: Per. 1																							
Gross steam	T/h		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	
Deaeration steam	T/h		1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	
Net steam	T/h		10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	
Process electricity usage	MW		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Parasitic electricity	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Import Electricity	MW		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Fuel usage	GJ/h HHV		32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	32.7	
Ash	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 emissions	T/h		4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	
Net electrical efficiency	% HHV		17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	
Net elec effic (f-to-p)	% HHV		35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	
Net thermal efficiency	% HHV		58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	58.2	
Condensate returned	T/h		5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
Treated water	T/h		5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	
Raw water	T/h		5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	
WTP loss	T/h		0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	
Boiler blowdown	T/h		0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	
Sewer	T/h		0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	

Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Cogen Case, 1 units operating : Flows for period: Per. 1																							
WHB steam	T/h		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	
Aux boiler steam	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Gross steam	T/h		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	
Deaeration steam	T/h		1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	
Net steam	T/h		10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	
Gross Gen. Electricity	MW		4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	4.84	
Process electricity usage	MW		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Parasitic electricity	MW		0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	
Export Electricity	MW		1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	
Import Electricity	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Cogen Fuel usage	GJ/h HHV		66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	
Aux Boiler Fuel usage	GJ/h HHV		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Total Fuel usage	GJ/h HHV		66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	66.1	
Ash	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 emissions	T/h		1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	
Net electrical efficiency	% HHV		26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	
Net elec effic (f-to-p)	% HHV		51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	
Net thermal efficiency	% HHV		65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	65.5	
Condensate returned	T/h		5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
Treated water	T/h		5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	
Raw water	T/h		5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	
WTP loss	T/h		0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	
Boiler blowdown	T/h		0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	
Sewer	T/h		0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	

Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Cogen Case, 0 units operating : Flows for period: Per. 1																							
WHB steam	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Aux boiler steam	T/h		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	
Gross steam	T/h		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	
Deaeration steam	T/h		1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16	
Net steam	T/h		10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	
Gross Gen. Electricity	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Process electricity usage	MW		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Parasitic electricity	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Export Electricity	MW		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Import Electricity	MW		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Cogen Fuel usage	GJ/h HHV		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Aux Boiler Fuel usage	GJ/h HHV		32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	
Total Fuel usage	GJ/h HHV		32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6	
Ash	T/h		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 emissions	T/h		4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	4.73	
Net electrical efficiency	% HHV		17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	
Net elec effic (f-to-p)	% HHV		35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	
Net thermal efficiency	% HHV		58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	58.1	
Condensate returned	T/h		5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
Treated water	T/h		5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	5.23	
Raw water	T/h		5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	5.75	
WTP loss	T/h		0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	0.523	
Boiler blowdown	T/h		0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	0.228	
Sewer	T/h		0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	0.751	

Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Benchmark annual flows																							
Gross steam	kT/year		97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	
Deaeration steam	kT/year		10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	
Net steam	kT/year		87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	
Process electricity usage	GWh		26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	
Parasitic electricity	GWh		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Import electricity	GWh		26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	
Electrical max. demand	MW		3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	
Fuel usage	TJ/year HHV		286	286	286	286	286	286	286	286	286	286	286	286	286	286	286	286	286	286	286	286	
Fuel maximum demand	GJ/h HHV		39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	
Ash	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 emissions	kT/year		41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	
Net electrical efficiency	% HHV		17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	
Net elec effic (f-to-p)	% HHV		34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	
Net thermal efficiency	% HHV		58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	
Condensate returned	kT/year		43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	
Treated water	kT/year		45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	
Raw water	kT/year		50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	
WTP loss	kT/year		4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	
Boiler blowdown	kT/year		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	
Sewer	kT/year		6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	

Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Cogen case annual flows																							
WHB steam	kT/year		92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	92.9	
Aux boiler steam	kT/year		4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	4.89	
Gross steam	kT/year		97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	97.8	
Deaeration steam	kT/year		10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	
Net steam	kT/year		87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	
Gross gen. electricity	GWh		40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	40.2	
Process electricity usage	GWh		26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	
Parasitic electricity	GWh		0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	0.433	
Export electricity	GWh		14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	
Import electricity	GWh		1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	
Import elec. max. demand	MW		3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	
Cogen fuel usage	TJ/year HHV		550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	
Aux boiler fuel usage	TJ/year HHV		14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	
Total fuel usage	TJ/year HHV		564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	
Fuel maximum demand	GJ/h HHV		79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	79.3	
Ash	kT/year		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
CO2 emissions	kT/year		16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	
Net electrical efficiency	% HHV		25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	
Net elec effic (f-to-p)	% HHV		50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	
Net thermal efficiency	% HHV		65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	65.1	
Condensate returned	kT/year		43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	
Treated water	kT/year		45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	45.8	
Raw water	kT/year		50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	
WTP loss	kT/year		4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	
Boiler blowdown	kT/year		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	
Sewer	kT/year		6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	

Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Benchmark: Operating cashflows (Real)																							
Fuel energy	$k/year	0.000	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	-859	0.000
Fuel Capacity	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ash	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Imported elec energy	$k/year	0.000	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	-1577	0.000
Exported elec energy	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Import elect. demand	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Raw water	$k/year	0.000	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	0.000
Sewer	$k/year	0.000	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	0.000
Treated water	$k/year	0.000	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	0.000
Steam chem dosing	$k/year	0.000	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	0.000
Fixed O_M	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Variable O_M	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Extra cost of CO2	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Operating cashflow	$k/year	0.000	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	0.000
Benchmark: Capital cashflows (Real)																							
Direct capital cost	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Extra connection charges	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Indirect capital cost	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Int. dur. construction (IDC)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Residual value	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total capital cost	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Benchmark: Tax supplementary calcs (Real)																							
Written down value (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Depreciation (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
WDV of conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Amort. conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gain/(loss) on disposal	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Interest on debt	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Benchmark: Total after tax cashflows (Real)																							
Operating cashflow	$k/year	0.000	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	0.000
Total capital cost	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CASH BEFORE DEBT & TAX	$k/year	0.000	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	-2496	0.000
Debt amount	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Principal & interest	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Tax	$k/year	0.000	0.000	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731	731
TOTAL CASHFLOW AFTER TAX	$k/year	0.000	-2496	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	-1765	731

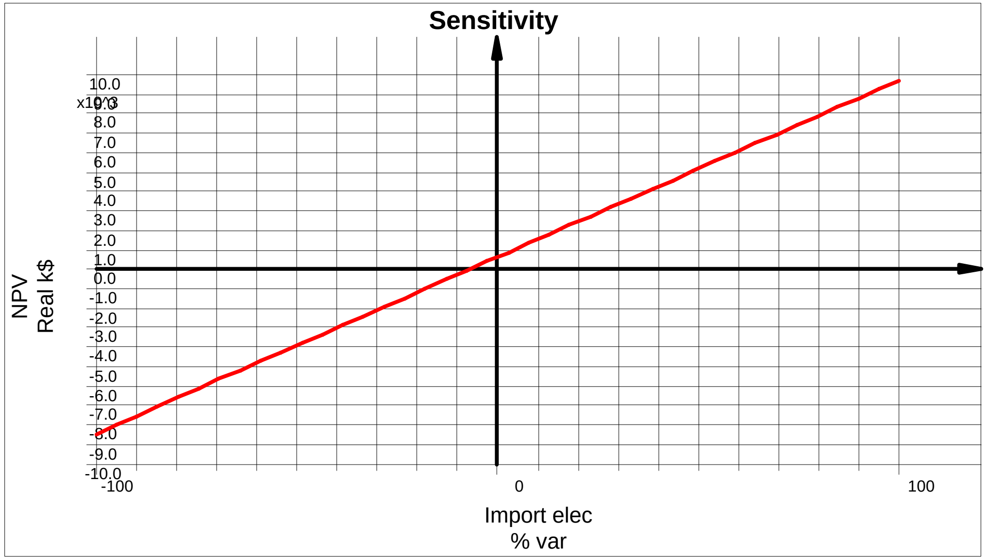
Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Cogen case: Operating cashflows (Real)																							
Fuel energy	$k/year	0.000	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	-1693	0.000
Fuel Capacity	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ash	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Imported elec energy	$k/year	0.000	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	-78.8	0.000
Exported elec energy	$k/year	0.000	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	0.000
Import elect. demand	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Raw water	$k/year	0.000	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	-40.3	0.000
Sewer	$k/year	0.000	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	-3.29	0.000
Treated water	$k/year	0.000	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	-11.4	0.000
Steam chem dosing	$k/year	0.000	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	-4.89	0.000
Fixed O_M	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Variable O_M	$k/year	0.000	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	0.000
Extra cost of CO2	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Operating cashflow	$k/year	0.000	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	0.000
Cogen case: Capital cashflows (Real)																							
Direct capital cost	$k/year	-6808	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Extra connection charges	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Indirect capital cost	$k/year	-1021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Int. dur. construction (IDC)	$k/year	-313	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Residual value	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total capital cost	$k/year	-8142	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cogen case: Tax supplementary calcs (Real)																							
Written down value (tax)	$k/year	6808	6144	5544	5003	4515	4075	3677	3319	2995	2703	2439	2201	1986	1792	1618	1460	1317	1189	1073	968	874	0.000
Depreciation (tax)	$k/year	0.000	-498	-450	-406	-366	-330	-298	-269	-243	-219	-198	-178	-161	-145	-131	-118	-107	-96.4	-87.0	-78.5	-70.8	0.000
WDV of conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Amort. conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gain/(loss) on disposal	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-874	0.000
Interest on debt	$k/year	0.000	-292	-264	-235	-206	-176	-146	-115	-83.6	-51.3	-18.2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cogen case: Total after tax cashflows (Real)																							
Operating cashflow	$k/year	0.000	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	0.000
Total capital cost	$k/year	-8142	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CASH BEFORE DEBT & TAX	$k/year	-8142	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	-1365	0.000
Debt amount	$k/year	4071	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Principal & interest	$k/year	0.000	-568	-554	-541	-528	-515	-502	-490	-478	-466	-455	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Tax	$k/year	0.000	0.000	631	608	587	567	548	530	512	495	479	463	452	447	442	438	434	431	428	425	423	676
TOTAL CASHFLOW AFTER TAX	$k/year	-4071	-1933	-1289	-1298	-1306	-1313	-1320	-1326	-1331	-1336	-1341	-902	-913	-918	-923	-927	-931	-934	-937	-940	-943	676

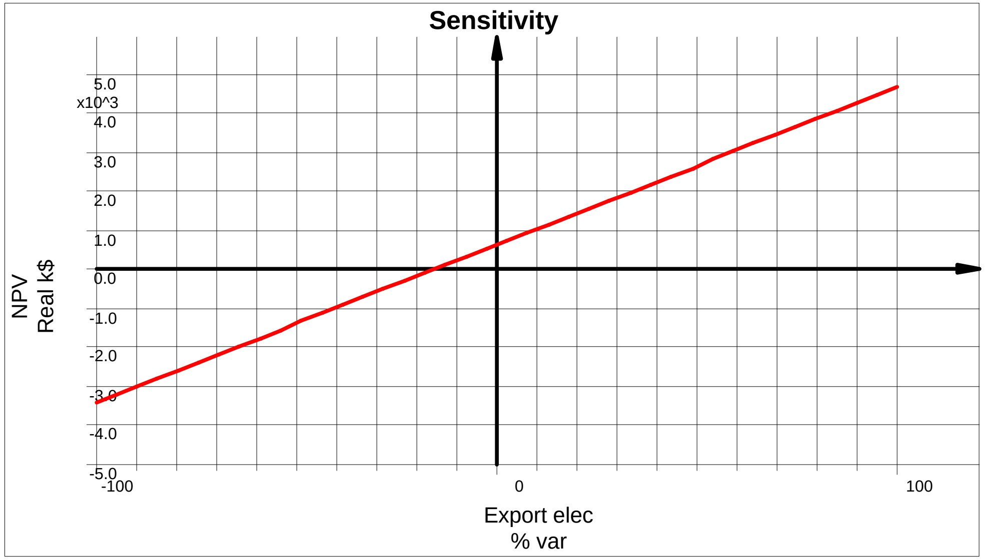
Approx date:		Oct-02	Oct-03	Oct-04	Oct-05	Oct-06	Oct-07	Oct-08	Oct-09	Oct-10	Oct-11	Oct-12	Oct-13	Oct-14	Oct-15	Oct-16	Oct-17	Oct-18	Oct-19	Oct-20	Oct-21	Oct-22	Oct-23
Year:		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Difference: Operating cashflows (Real)																							
Fuel energy	$k/year	0.000	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	-834	0.000
Fuel Capacity	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Ash	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Imported elec energy	$k/year	0.000	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	1498	0.000
Exported elec energy	$k/year	0.000	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	668	0.000
Import elect. demand	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Raw water	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sewer	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Treated water	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Steam chem dosing	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fixed O_M	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Variable O_M	$k/year	0.000	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	0.000
Extra cost of CO2	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Operating cashflow	$k/year	0.000	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	0.000
Difference: Capital cost cashflows (Real)																							
Direct capital cost	$k/year	-6808	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Extra connection charges	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Indirect capital cost	$k/year	-1021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Int. dur. construction (IDC)	$k/year	-313	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Residual value	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total capital cost	$k/year	-8142	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Difference: Supplementary cashflows (Real)																							
Written down value (tax)	$k/year	6808	6144	5544	5003	4515	4075	3677	3319	2995	2703	2439	2201	1986	1792	1618	1460	1317	1189	1073	968	874	0.000
Depreciation (tax)	$k/year	0.000	-498	-450	-406	-366	-330	-298	-269	-243	-219	-198	-178	-161	-145	-131	-118	-107	-96.4	-87.0	-78.5	-70.8	0.000
WDV of conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Amort. conn. charges (tax)	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gain/(loss) on disposal	$k/year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-874	0.000
Interest on debt	$k/year	0.000	-292	-264	-235	-206	-176	-146	-115	-83.6	-51.3	-18.2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Difference: Total after tax cashflows (Real)																							
Operating cashflow	$k/year	0.000	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	0.000
Total capital cost	$k/year	-8142	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CASH BEFORE DEBT & TAX	$k/year	-8142	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	1131	0.000
Debt amount	$k/year	4071	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Principal & interest	$k/year	0.000	-568	-554	-541	-528	-515	-502	-490	-478	-466	-455	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Tax	$k/year	0.000	0.000	-99.6	-122	-143	-163	-183	-201	-218	-235	-252	-268	-279	-284	-288	-293	-296	-300	-303	-305	-308	-54.5
TOTAL CASHFLOW AFTER TAX	$k/year	-4071	562	477	468	460	452	446	440	434	429	424	863	852	847	842	838	834	831	828	825	823	-54.5

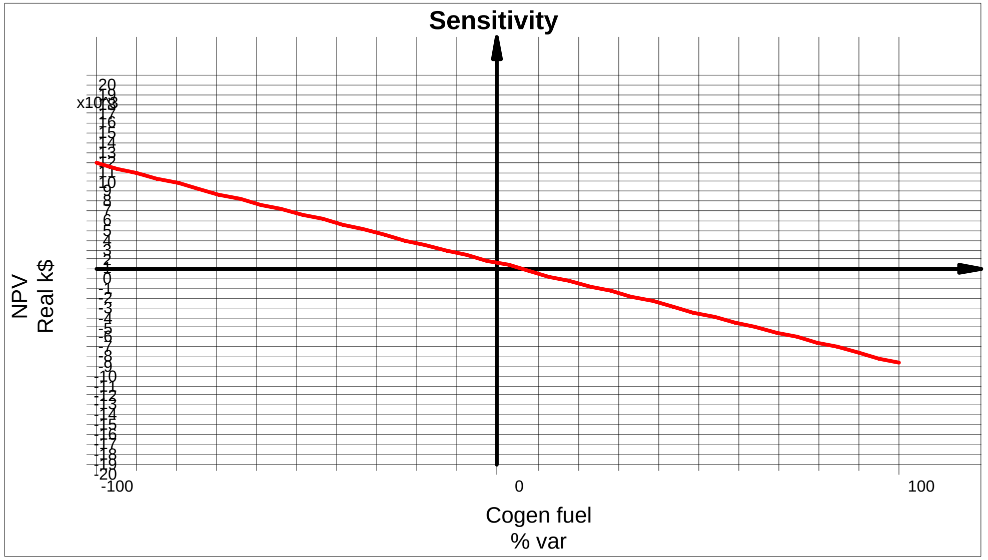
DIFFERENCE: Cashflow parameters

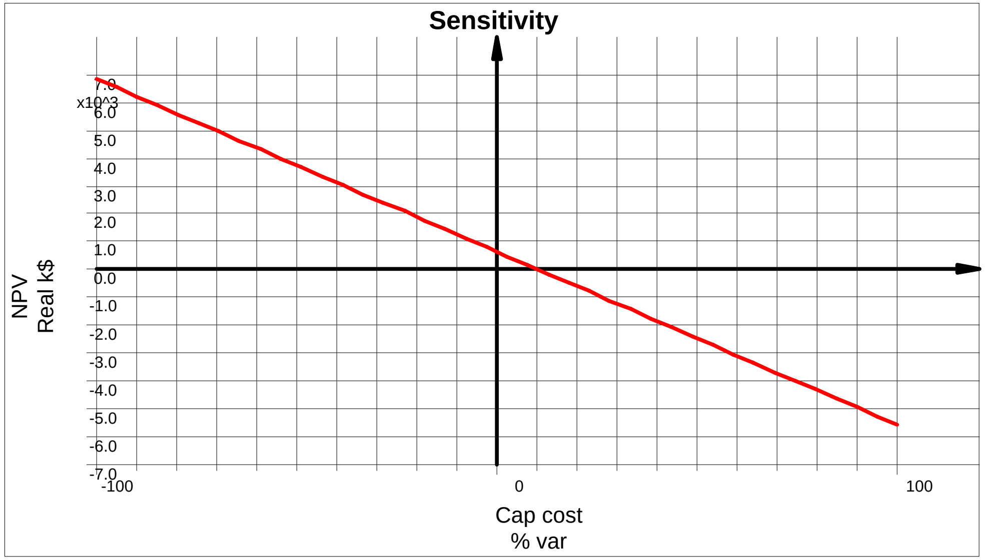
NPV @ 10.4% Real $ 629k
IRR (equity) 12.4% Real - Appears attractive
IRR 12.6% Real, before interest & tax
Simple undiscounted payback (equity): 7.24 years
Simple discounted payback (equity): 18.19 years
Project cost of lifetime avg CO2 saving: $ -3.0/T
Project cost of 5 x final year's CO2 saving: $ -5.0/T
Project global CO2 impact (incl offset elect impact): -0.63T/MWh generated
Project avg equiv CO2 intensity (excl offset elect): 0.36T/MWh generated

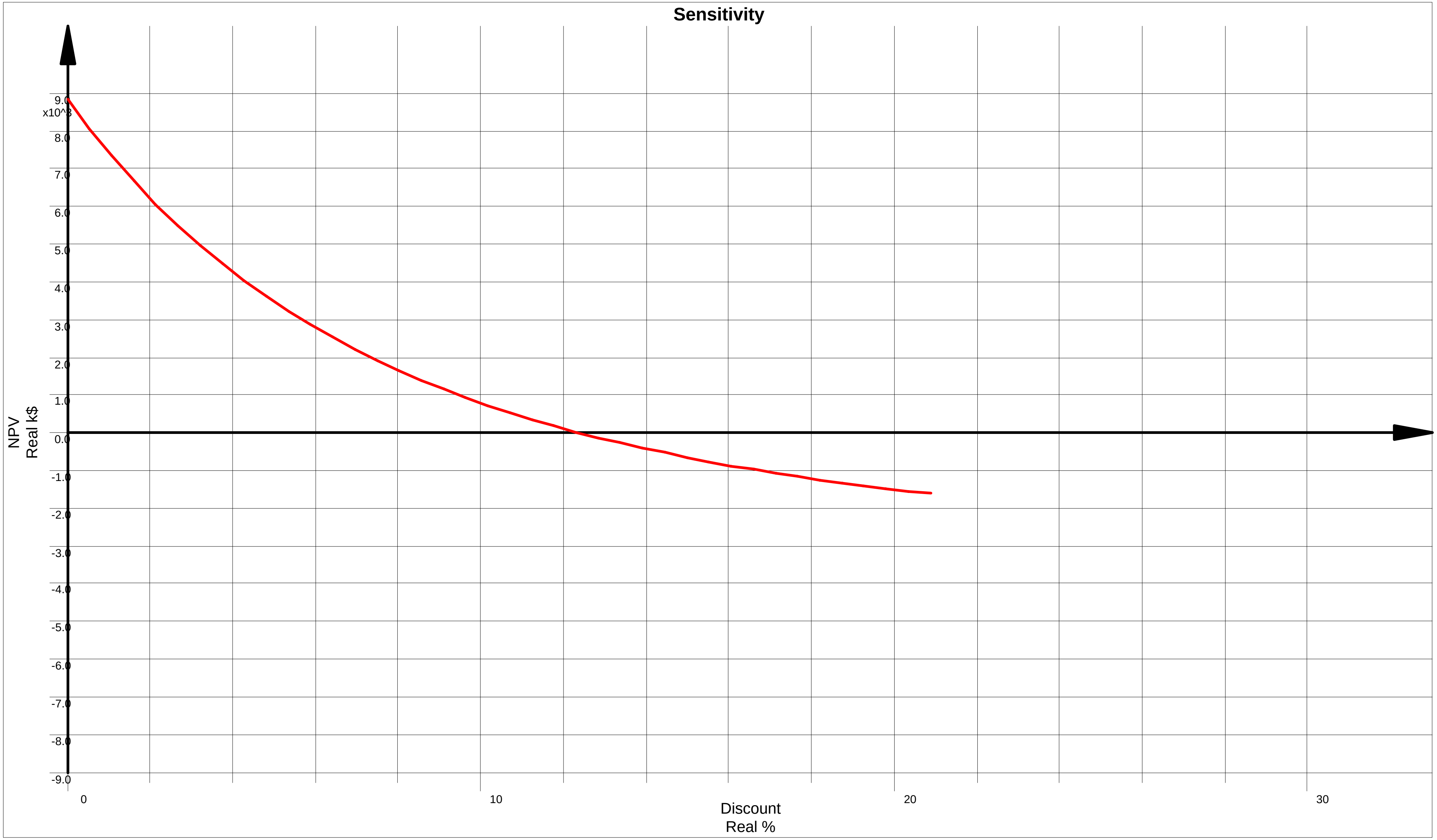
Difference: Unit oper costs (before interest & tax)(Real)																							
Var generation cost	$/h	0.000	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	223	0.000
Var non-generation cost	$/h	0.000	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	98.1	0.000
Var diff gen/no-gen un cost	$/MWh	0.000	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	0.000
Long run diff un cost (>tax)	$/MWh	50.2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000


Sensitivity
NPV
Real k$
x10^3
Import elec
% var


Sensitivity
NPV
Real k$
x10^3
Export elec
% var


Sensitivity
NPV
Real k$
x10^3
Cogen fuel
% var


Sensitivity
NPV
Real k$
x10^3
Cap cost
% var


Sensitivity
NPV
Real k$
x10^3
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
-1.0
-2.0
-3.0
-4.0
-5.0
-6.0
-7.0
-8.0
-9.0
0
10
20
30
Discount
Real %