Techno-Economic Evaluation – Cleaner Coal Plant Operability

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PROJECT 141 – TECHNO-ECONOMIC EVALUATION OF CLEANER COAL PLANT OPERABILITY

Prepared for

DTI CLEANER COAL TECHNOLOGY PROGRAMME

by

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SUMMARY

Clean power technologies have been developed to achieve high efficiencies and low emissions due to stringent environmental regulations. The obvious benefits of clean technologies were adequate while the power market was relatively stable and the plant could operate in base-load condition. However, in the current liberalised power market, electricity prices fluctuate, and thus the operational flexibility plays an important role in the plant profitability.

Powergen and UMIST (Department of Process Integration) have collaborated in a project to develop a means of ascribing a financial value to the operational flexibility (start-up times, ramp rates, minimum stable generation etc) of generating units. The project was partly funded through Powergen (£55k) and partly through support from the DTI's Clean Coal Technology Programme (£50k). This report summarises the Ph.D. study undertaken and presents the results and conclusions.

The basic purpose is to investigate the operational flexibility for power plants generating using coal or heavy fuel oil, in particular looking at Integrated Gasification Combined Cycle plants (IGCCs). The operational flexibility is defined as the ability of the plant to change its operation to respond to the fluctuating electricity prices. The profit that a plant makes is then compared to the profit of a perfectly flexible plant (i.e. instantaneous start-up and shutdown times) to give the cost of inflexibility (Operational Inflexibility Cost [OIC]).

An algorithm has been developed to determine the costs associated with operational inflexibility and the trade-off between increased efficiency and increased flexibility. If the model were to be used for the assessment of new plant, extensive data would be required to ensure that the results were meaningful, as the model in its current form

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contains many assumptions about the plants therein due to the lack of operational data available for IGCC. The scheduling algorithm is not fully optimised, due to the complex nature of such an item and the time constraints of the project. It would require further development to give definitive (rather than indicative, as at present) results.

It should be noted that the model assumed PF performance similar to that of existing UK plant (typically 30 years old) against projected performance of *new build* IGCC. The paper does not therefore give an accurate like for like comparison of the two technologies. In addition, start-up costs and times for IGCC are highly uncertain and could be much higher than the assumed numbers. The paper serves to demonstrate the methodology rather than give definitive values for a particular technology. Against that background, the conclusions were as follows.

Of the plants studied, the fully integrated IGCC has the best overall thermal performance. The higher the fuel price, the more beneficial it is to operate the IGCC compared with PF plant. In terms of the degree of integration, the fully integrated IGCC has better performance rather than the non-integrated and the partially integrated IGCC plant. The calculated operational inflexibility costs ranged between 0 (for base load operation) and about £2.5M p.a. (for about 55% utilisation) on a 250MW unit.

Co-production of hydrogen has also been investigated as a means of keeping the gasifier warm while the GT is off load, thereby minimising its start-up time. The hydrogen can then be utilised elsewhere in the plant or sold on. Co-production is not affected by the efficiency, but by the degree of integration of the ASU (Air Separation Unit). The 0% and 50% integrated IGCC plants (particularly the 50% integrated IGCC) are ideal for co-production as air can still be fed to the gasifier when the GT is not running. Hydrogen co-production increases the income of the plant through the provision of an extra income stream, decreasing the payback time of the plant, though there is the extra associated capital cost of the hydrogen production plant.

Maintenance scheduling has been modelled in order to find the most financially viable time for maintenance to occur (i.e. minimise the loss of profit during the maintenance period). This can also aid decisions on which critical items to hold in stock if reliability data is known down to component level. The model can provide numerical an indication of when to schedule maintenance considering maximum profitability or maximum reliability.

The overall profitability (excluding fixed costs and capital cost payback) is more dependent on the base capability of the plant than its flexibility. The higher the efficiency of the plant, the less relevant operational flexibility becomes, since high efficiency plant will run base load more often and for longer than lower efficiency plant (if all other factors are equal, such as fuel price, etc). The higher efficiencies of highly integrated IGCCs can offset the cost associated with the longer start up times of the gasifier, due to the increased likelihood of base load running).

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CONTENTS

1 INTRODUCTION

Powergen and UMIST (Department of Process Integration) have collaborated in a project to develop a means of ascribing a financial value to the operational flexibility (start-up times, ramp rates, minimum stable generation etc) of generating units. The project is being partly funded through Powergen (£55k) and partly through support from the DTI's Clean Coal Technology Programme (£50k).

The project has lasted 3 years, from January 2000 to December 2002. This is the final report, which summarises the PhD study and also presents the results and conclusions of the project. The methodology was presented in the Power Technology Report PT/02/BB1572/R.

2 BACKGROUND

In liberalised power generation markets, there can be considerable rewards for being able to generate in a flexible manner and, conversely, the penalties incurred by an inflexible unit can be significant. Operational parameters such as start-up times, load-following ability and Minimum Stable Generation (MSG) are therefore of increasing interest both for existing units and in evaluating options for new plant.

However, under almost all circumstances, better operational flexibility comes at a price, whether this be increased capital costs or expenditure, lower efficiency, lower availability or shortened plant life. As ever, therefore, there is a trade-off between high operational flexibility on the one hand and other desirable plant features, such as low running costs, high availability, high efficiency and minimum capital investment, on the other. It is therefore desirable to be able to put a monetary value to increased plant flexibility in order to be able to determine if the benefit gained outweighs the costs incurred (whether explicitly or implicitly).

One area in which operational flexibility is particularly important is in the field of new, advanced coal generating technologies. Development of new generating technologies has often overlooked plant flexibility in pursuit of other goals, chiefly high efficiency and environmental performance. This is partly because until recently, it could be assumed that any new, high efficiency unit would be run base-load for its early years of operation and thus any losses associated with poor operational flexibility could be literally discounted as arising only towards the end of the station's life.

However, under liberalised power markets, this assumption can no longer safely be made. By way of example, both of the two large European coal-fired IGCC (Integrated Gasification Combined Cycle) units, at Buggenum in The Netherlands and Puertollano in Spain, were designed and built for nonliberalised markets in which the units could be run at base-load. Because of this, the designs chosen feature a high degree of integration between the various parts of the overall IGCC process, sacrificing flexibility for high efficiency. The electricity markets of both Spain and The Netherlands have since been liberalised and, as a result, both units are struggling because falling prices mean that they are not always successful in bidding into the system; and their extremely long start-up times means that frequently they have only just got to full load before being required to shut down again. The very poor operational flexibility of IGCC has been identified by the Foresight Task Force as one of the major barriers to its adoption (Foresight, 1999), which recommended that techno-economic evaluation of operability be made a high priority research area.

In light of this, a project was set up by Powergen to investigate ways of putting a monetary cost to plant inflexibility. The project is being undertaken in collaboration with UMISTs Department of Process Integration, who are world leaders in the science of process optimisation and who possess the necessary optimisation and computing expertise. The project is being part-funded by the DTI under its Cleaner Coal RD&D programme. The DTIs interest is primarily because of the importance of this subject to IGCC; however, the issue is of general applicability to all types of generating technology.

3 THEORY AND IMPLEMENTATION

The extent to which the operational flexibility of a unit affects its overall commercial performance depends on the market conditions, and in particular, the price profile.

At the extreme, if a unit has a long-term power purchase contract under which it is required / permitted to run continuously at base-load, then operational flexibility is not really an issue. Under such circumstances, the only residual issues pertaining to operational flexibility are:

i since the unit will shut-down on occasions, for planned outages or as a result of breakdown, shut-down and start-up times are still of some consequence (the more so, the less reliable the unit);

ii if the price paid for the power is not constant, but varies with time, then there may be occasions when it is economic to shut-down rather than continue generation (i.e., when the marginal cost of generation exceeds the price paid), again, shut-down and start-up times are of some relevance here.

To examine the effects of operational inflexibility on a unit’s commercial performance in a market where units are required to operate flexibly, it is best to start by considering how a perfectly flexible unit would operate in such circumstances.

3.1 The Perfectly Flexible Unit

This is a hypothetical entity conceived for the purposes of this project that provides the base case or reference case against which units with finite operational flexibility can be compared.

The hypothetical, perfectly flexible unit has the same characteristics as the real unit for which it provides the reference, i.e.:

i same efficiency[1],
ii same fuel and fuel costs,
iii same availability[2],
iv same capacity,
v same capital costs,
vi same fixed costs.

However, the hypothetical unit has perfect flexibility, defined as:

i stable operation throughout the range 0-100% of capacity,
ii instantaneous load-following ability,
iii zero start-up times and costs[3],
iv zero shutdown times and costs[4].

When faced with an electricity market in which the purchase price varies discretely with time, as shown schematically in Figure 1(A), the optimum running strategy for the perfectly flexible unit (i.e. the strategy that maximises gross profits) is to run the unit when the marginal cost of generation is less than the marginal revenue (i.e. power purchase

[1] The efficiency of real units falls off at part-load. Since this is in effect a form of inflexibility (because it makes part-load operation less attractive than would otherwise be the case), strictly speaking, the hypothetical unit should have the same efficiency throughout its range of load as the real unit does at the load where its efficiency is at a maximum.

[2] A unit that has both poor reliability and is inflexible suffers twice over because after each breakdown it takes a long time to get back to full load. Whether this loss of revenue is attributed to its poor reliability or its poor operational flexibility is a matter of definition. For the purposes of this project, this penalty will be regarded as part of the cost of inflexibility.

[3] Start-up costs can be thought of as comprising both costs actually incurred during start-up, such as fuel used in warming the unit, and costs associated with the degradation in plant performance and life as a result of the thermal and mechanical cycling of equipment.

[4] Similarly, shutdown costs include the cost of the fuel equivalent to the stored thermal energy lost during shutdown plus the costs associated with plant degradation. The latter, which are really costs of a start-stop sequence, can be arbitrarily designated as either shutdown or start-up costs.

price). To a first approximation, the marginal cost is the cost of fuel used. In other words, if the power price exceeds the marginal cost, the unit runs at full load, otherwise, it does not run (Figure 1(B)). The gross profit made per period is thus the capacity of the unit multiplied by the difference between the price and marginal cost, assuming that this is negative (Figure 1(C)):

$$P_{t,id} = C\left(X_t - K_t\right)\Delta t \quad \hbar\left(X_t - K_t\right)$$

where:

$\hbar(x)$ is the Heaviside Unit Function (= 1 if x> 0 and 0 if x<0)
$P_{t, id}$ is the gross profit in time period t (£) for the ideal unit;
C is the unit capacity (MWe);
X_t is the power purchase in time period t (£ MWe^{-1});
K_t is the marginal generating cost in time period t (£ MWe^{-1});
Δt is the length of the time period.

It should be noted that this approach requires that the variation in power price with time can be described as a series of equal, discrete periods during each of which the price remains constant. In some markets, such as the (former) English Pool, this is (was) done explicitly (but of course, only in retrospect: for the model to be of real use, it requires predictions of costs for the future). In other markets, these values may not be as explicit, but it should be possible to make some predictions based on price volatility. It does however, need to be borne in mind that the predictions of the model can be no better than the predictions of the future short-term fluctuations on electricity price.

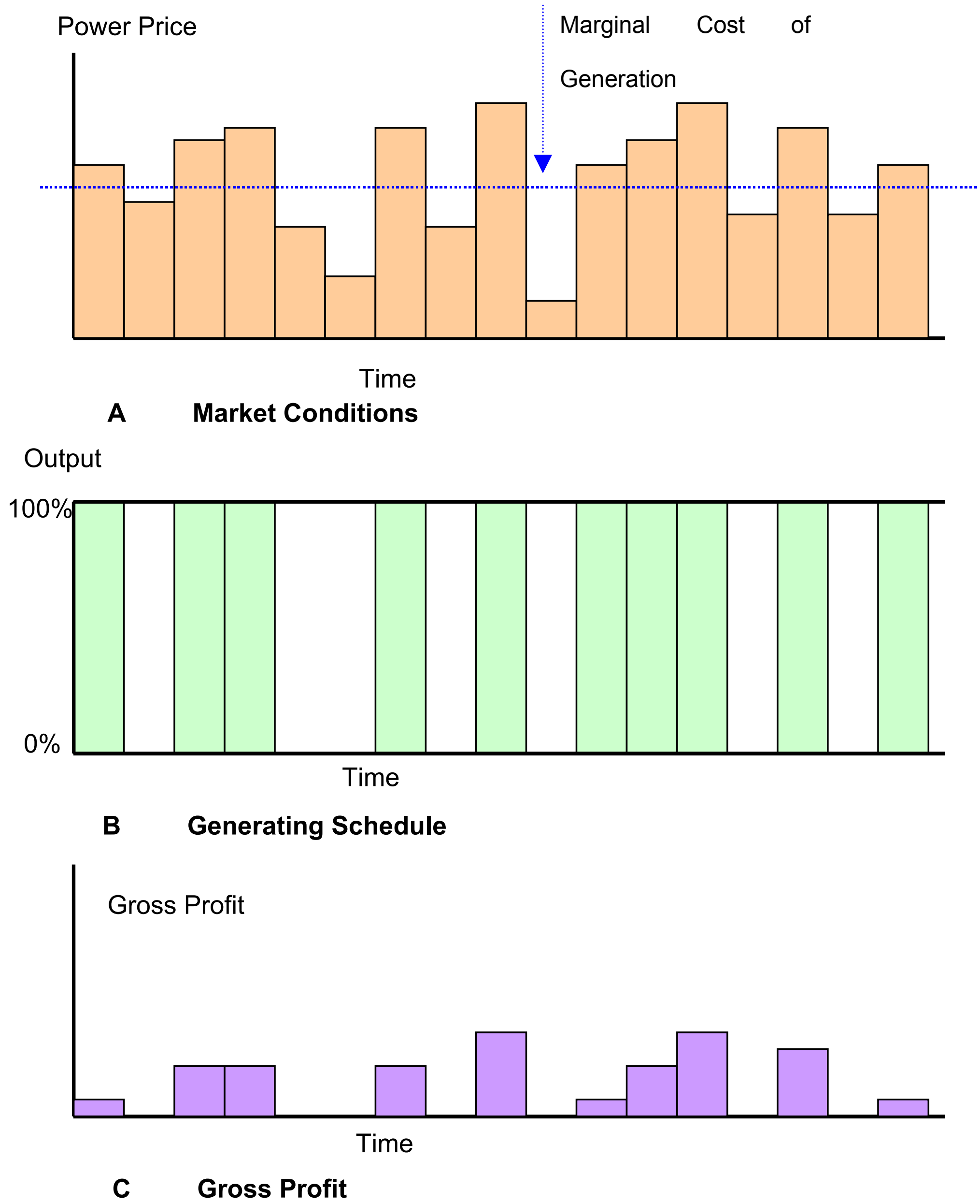


Figure 1: Operating Strategy for the Perfectly Flexible Unit

3.2 Real, Inflexible Unit

A real unit is not infinitely flexible. In particular, it has finite start-up and shutdown times and limited load-following capability (both in terms of rates and range). These characteristics impose *intrinsic* costs[5] on the operation of the unit. Some of these intrinsic costs are explicit – such as the cost of the fuel used during start-up, some less so, such as the costs of damage to the unit incurred as a result of increased thermal, chemical and mechanical cycling.

However, in addition to these intrinsic costs, operational inflexibility also gives rise to further *extrinsic* opportunity costs[6] that occur because the unit is not able to operate in such a way as to take full opportunity of the market. This is illustrated in Figure 2.

Figure 2(A) shows the same market conditions as used in Figure 1. Now, however, we assume that the unit in question takes one time period to carry out a hot restart (i.e. to the point where the unit is resynchronised) and a further period to attain full-load.

The unit faces the problem that there are periods of time during which the prevalent power purchase price is less than its marginal cost of generation. During these periods it could:

i Carry on running at MSG (minimum stable generation) and incur losses equivalent to the difference between purchase price and marginal cost times MSG times the time period.

ii Shutdown and restart as to meet full-load at the point at which the power purchase price exceeds the marginal cost. This incurs shutdown and start-up costs and losses whilst generating at below the breakeven power purchase price.

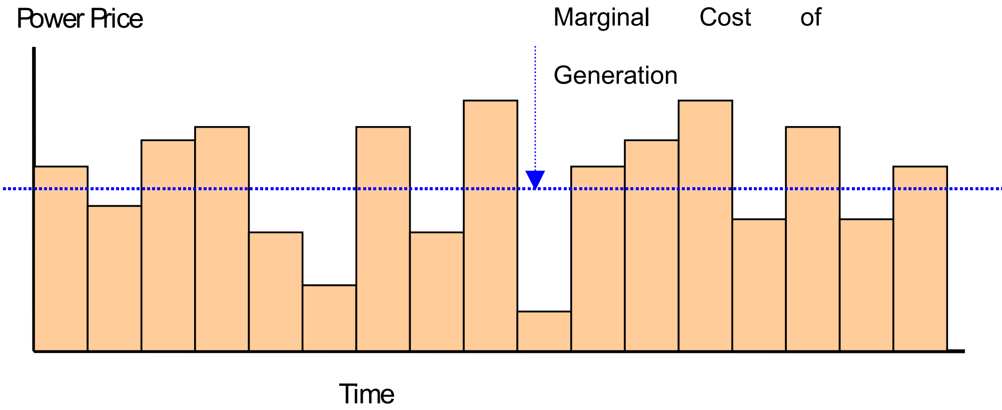
iii Shut-down and restart so as to resynchronise at the point at which the power purchase price exceeds the marginal cost. This incurs shutdown and start-up costs and opportunity costs because the unit is generating only at part-load for a time after start-up.

Option (iii) is shown in Figure 2(B); Figure 2(C) shows the gross profit arising from such as scheme of operation. Comparison with Figure 1(C) shows that the total profit made over the timeframe shown has

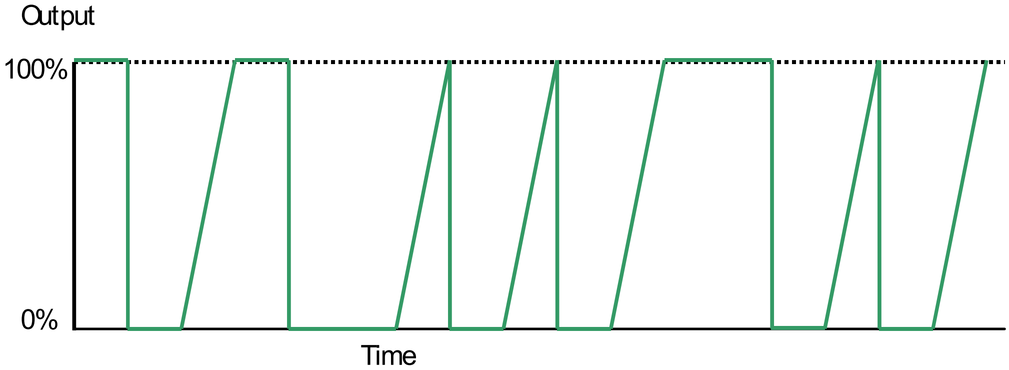
[5] The costs we have generically termed ‘intrinsic’ because they arise directly from the technological characteristics of the unit.

[6] Extrinsic because they arise from the characteristics of the market in question.

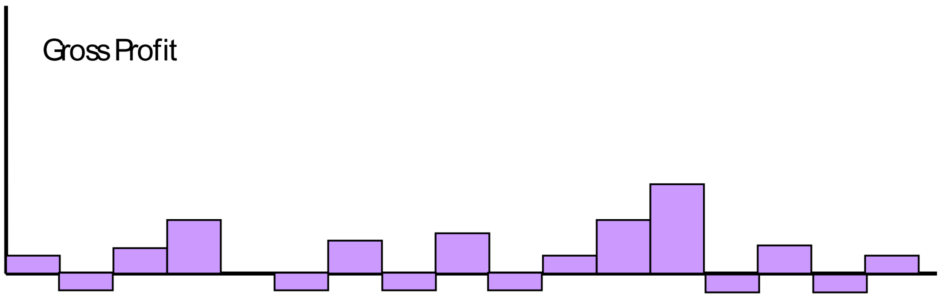
been considerably reduced; this is attributable to the inflexibility of the unit.



A Market Conditions



B Possible Generating Schedule



C Gross Profit

Figure 2: Operational Strategy for a Real, Inflexible Unit

There are obviously many different operating strategies that could be used when faced with a market condition such as that described above. All of these will have their own cost of inflexibility, defined as:

Cost of inflexibility =

Gross Profit made by perfectly flexible unit – Actual Gross Profit

The problem is therefore to determine which of the many modes of operation (or 'trajectories') maximises the Gross Profit for the real unit and thus gives the lowest inflexibility cost, as this represents the true cost of plant inflexibility.

3.3 Determining the Optimum Operating Trajectory

Even if we simplify the problem so that the unit can only ever be in one of two states, on or off, then the total number of possible trajectories is huge, being given by 2^N where N is the number of time periods under consideration. For example, over a period of a day, with changes in power purchase price every half-hour, there are $2^{48} \approx 3\text{x}10^{14}$ different trajectories that would need evaluation. Over the period of a week, this would rise to $2^{336} \approx 10^{100}$.

To get round this problem, an optimisation procedure has been developed that uses mixed integer linear programming. The basic idea behind the algorithm that has been developed is that each of the possible states of the plant (e.g., on, shutting down, off, starting up) is represented by a binary variable (e.g. y_{on}, y_{shut}, y_{off} and y_{start}) which is set to 1 if the unit is in that state and 0 otherwise. For example if the unit is running then $y_{on} = 1$ and $y_{shut} = y_{off} = y_{start} = 0$. These variables are used to define constraints on the trajectory of the unit. For example, since if a unit is in operation in time period t then it cannot be starting up in time period t+1 so:

$$y_{on}(t) \quad + \quad y_{start}(t+1) \quad \leq \quad 1$$

3.4 Data Pre-Processing

It was discovered that even using the techniques described, the complexity of computation was such that the model could not comfortably cope with more than about 2 weeks of operation at a time (i.e. about $2\text{x}7\text{x}48 \approx 700$ different time periods or $2^{700} \approx 10^{200}$ different possible trajectories). It has therefore proven necessary to pre-process the input data by grouping together periods where the power purchase price is consistently greater than, or less than the marginal cost of generation. This simplifies the problem since if there is a long period of time when the power purchase price remains roughly constant then there is no reason to alter the operational state of the plant part way through. By doing this, it has proven possible to run for at least an entire month's worth of power purchase data in one (relatively fast) computer run and to therefore cover an entire year relatively easily [7].

[7] One year is a particularly appropriate period for the analysis since the seasonal fluctuations in power price mean that after one year, trends tend to repeat.

This data pre-processing is easily achieved using Excel.

4 SUMMARY OF THE METHODOLOGY

4.1 Operational Scheduling

The algorithm that has been developed uses basic input parameters such as the following: coal feed rate, ramp rates, load at synchronisation, load at MSG, full load output power and ASU power consumption/MW generated. The objective is then to find the appropriate operational mode for each time period so as to increase the actual (achieved) profit and decrease the Operational Inflexibility Cost (OIC).

To achieve this, the model calculates the profit from ON (full load), MSG and OFF operations for each time period and selects the appropriate mode to satisfy the necessary constraints and objectives.

The algorithm provides an output of; the optimal operation for each period, optimal start-up and shutdown times, the optimal time taken for loading and de-loading the unit, the 'ideal' profit for an 'ideal' unit, the maximum profit that can be realised based on the operational strategy and the Operational Inflexibility Cost.

4.2 Hydrogen Co-Production

One of the drawbacks of using gasifiers for power generation is the long start-up times that are required if the gasifier is cold (up to 100 hours). If the syngas from gasifier is converted to produce hydrogen when power generation is not required, then the gasifier can be kept warm, reducing the start-up times when power generation is required. The hydrogen can then be stored for another use or sold on to create an extra income stream and increase the profitability of the plant.

Co-production of hydrogen (and the consequent extra income) is dependent on the degree of integration of the plant. If the plant is fully integrated then air for the gasifier is only available when the GT is on load, therefore hydrogen can only be produced when the GT is on load. If, however, the plant is partially integrated or non-integrated then hydrogen can be produced when the GT is not running. This can be useful as if the power price is low; it may be more beneficial to produce hydrogen instead.

The algorithm operates in a similar manner to the algorithms for operational scheduling, but in addition will give the profit for the co-production of hydrogen and the appropriate times for when to (or not to) produce hydrogen.

4.3 Maintenance Scheduling

Scheduling maintenance for IGCC can be more expensive for IGCC plants than for other types of generation, as the start-up time for a gasifier from cold can be up to 100hrs, during which time potential profit is being lost; as against a cold start-up time of less than 12 hours for a PF plant.

The maintenance algorithm uses probabilities for failure for items of plant and the profits for the periods in question to calculate when to carry out the maintenance to either:

1) minimise the profit loss by maintaining the plant when the potential profit is at its lowest, or

2) maintain plant reliability at a higher level (therefore minimising the likelihood of a forced outage) though this may require maintenance when potential profits are greater.

5 RESULTS

5.1 Operational Scheduling

The aim of the research is to develop a methodology that is able to suggest the optimal running strategy for power generation technologies taking into account the fluctuating electricity prices and the start up / shut down time.

An algorithm has been developed considering the operation scheduling for power generation plants. The outputs of the algorithm are the optimal time to change the mode of operation and the optimal mode (ON, OFF or MSG [minimum stable generation]) for each time period. Figure 3 shows the difference between the length of time to ramp output power [assumed by the model to be instantaneous] – blue line, with the actual [finite] time to ramp power as found in practice – red line.

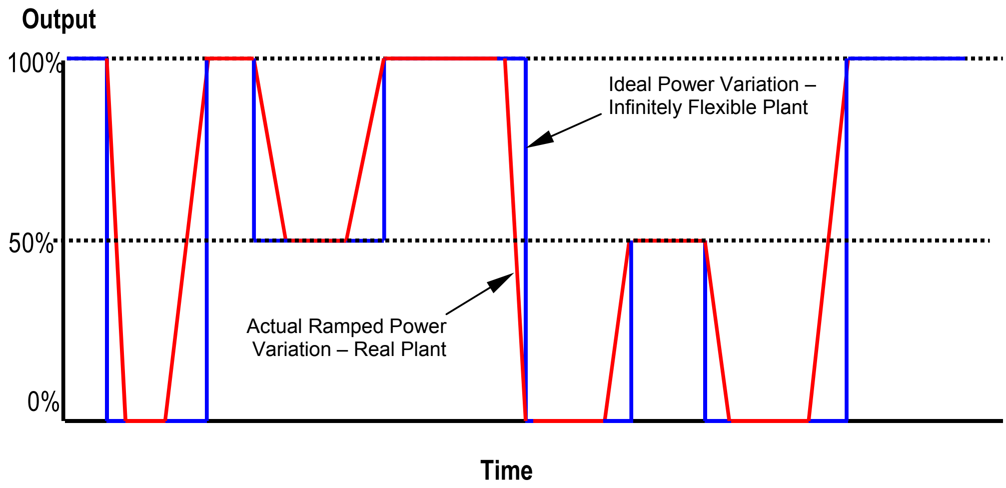


Figure 3: Ideal vs Actual Operation for a Power Plant

The x- axis represents the time and the y-axis shows the output power variation based on the power price. The blue lines indicate the ideal power variation for an infinitely flexible plant, whereas the red lines show the ramped variation in output power for a real plant. The ramp length depends on the maximum power, MSG power and the value of power after synchronisation. The inflexibility cost is attributed to the time taken to ramp power (as opposed to the immediate response of a perfectly flexible plant). As a result, the plant tends to have the following operational response:

1. It is not possible always to have the maximum power generation when the power price is high and OFF mode when the power price is low in comparison to the fuel price. As a result, MSG operation is considered.

2. Power is produced during the time for partial (from maximum to MSG mode / from MSG to OFF mode) or total (from maximum to OFF mode) shut down / start up when the time periods permits these operational changes. However, it is possible to have electricity prices lower than the fuel cost during the start up / shut down processes.

3. When the time period is not adequate for ramping output, the plant operates to its maximum capacity, although there will be a loss of profit.

Apart from the operation modes and the time for power variation, the total profit is obtained from the algorithm. The next section compares the income of different power generation technologies.

5.1.1 Profit vs. Power Technologies

The operational scheduling for IGCC plants, considering different degree of integration for the Air Separation Unit (ASU), and PF plants have been investigated. The results regarding the profit from their operation are based on the following assumptions from Table 1.

Table 1: Assumptions regarding basic parameters for the operation of IGCC and PF plants. The percentage figure (100%, 50%, 0%) denotes the extent of plant integration (full, partial or none) of the gasification combined cycle.

Parameters for ~250 MW power output	100% IGCC	50% IGCC	0% IGCC	PF
Coal Feed (tn/d)	2500	2500	2500	2500
Fuel cost (pounds/ GJ)	2.2	2.2	2.2	2.2
Efficiency	43%	41.5%	40%	37%
Power for ASU operation (Mw)	15	22.2	40	0
Maximum number of OFF modes/month	30	30	30	30
Standard cost / start up (pounds/start up)	3000	3000	3000	3000
Power after synchronisation (MW)	25	25	25	100
Offload time for hot start up (hrs)	<6	<6	<6	<6
Offload time for cold start up (hrs)	>48	>48	>48	>48

Figure 4 shows the actual profit per month when 2500 tn/day of coal costing 2.2 £/GJ is used. Electricity price has been taken as the pool purchase price for the year 1997.

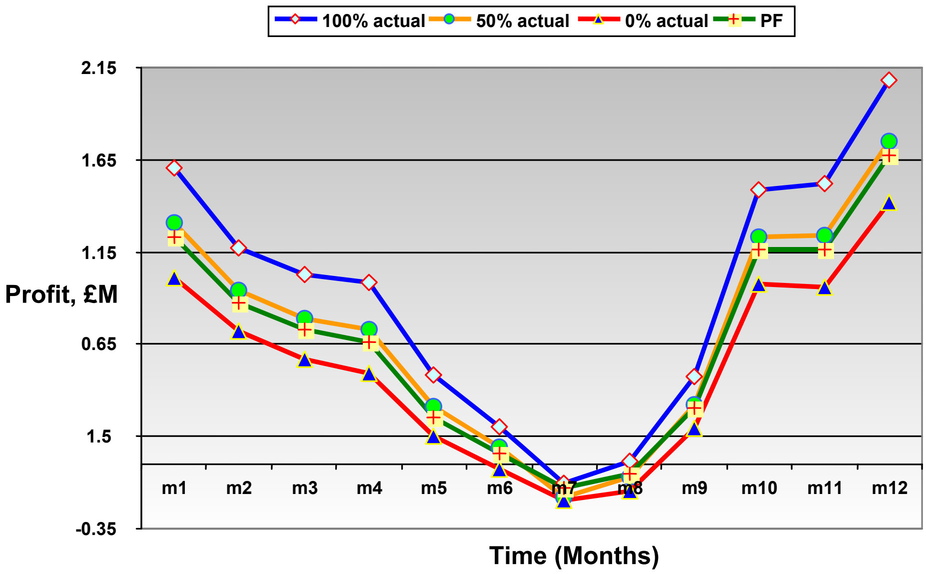


Figure 4: Monthly actual profit for IGCC and PF plants considering fuel price equal to 2.2 £/GJ, based on 1997 electricity prices.

The most significant observation is the profit loss (or negative profit) between months m6 and m8. The reason for that performance is a low electricity price in combination with a high fuel price. It should be noted that the model does not indicate precisely in which month there is to be a profit loss. However, the graphical representation of actual profit indicates indirectly whether the plant should operate or not. Other information that can be obtained from the graphical profit estimation is which plant has the maximum profit and minimum OIC[8] per month. These figures are useful when a company owns different power technologies and needs to select which plant to operate as a priority so as to maximise the overall profit.

Suppose that we have the case as per Figure 4 where a profit loss is observed. If the unit requires a maintenance outage, this would be the optimum time. Table 2 shows the actual profit and OIC if the plant is on outage for the months when the profit is negative.

[8] Operational Inflexibility Cost - the difference between the profit of an actual plant and the profit from a perfectly flexible plant.

Table 2: OIC and actual profit if the plant is not operated for the months that result in a profit loss.

	Actual profit (for months stated)	Total Profit per year, £M	OIC per year, £M	OIC decreases
M7 100% IGCC	0	11.1	2.18	4.59%
M7,M8 50% IGCC	0	8.71	2.22	10.1%
M6,M7,M8 0% IGCC	0	6.50	2.24	14.2%
M7,M8 PF	0	8.11	2.43	7%

It can be concluded that the PF plant has the highest OIC although its actual profit is greater than that of non-integrated plant and that fully integrated IGCC is the most profitable plant (mainly due to its efficiency).

Figure 5 shows the profit when the fuel price is decreased from 2.2 £/GJ to 1.8 £/GJ.

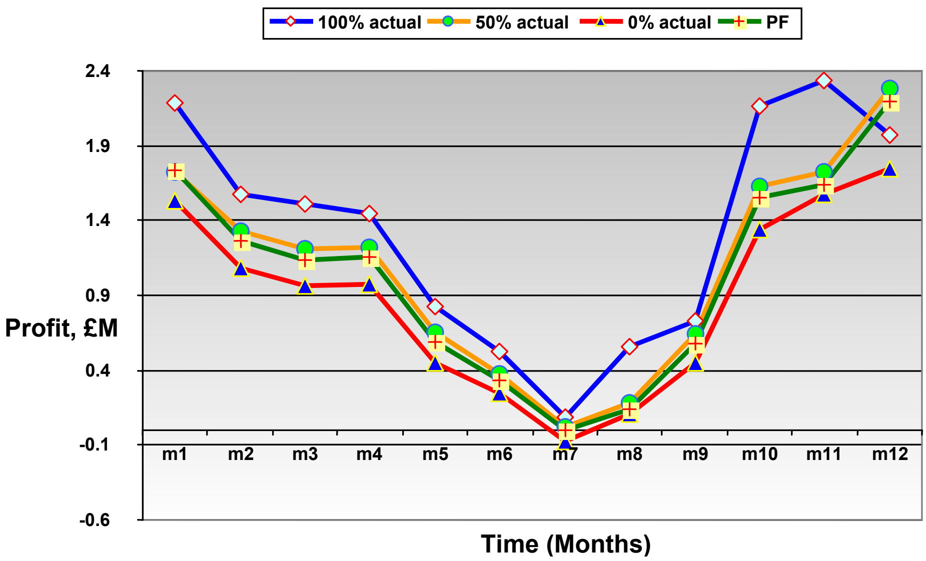


Figure 5: Monthly actual profit for IGCC and PF plants considering fuel price equal to 1.8 £/GJ, based on 1997 electricity prices.

From Figure 5 it can be seen that the number of months where profit loss occurs are fewer than before. Furthermore, comparing non-integrated IGCC with PF plant in Figures 4 and 5, similar performance is identified between the two technologies

In order to draw conclusions between non-integrated IGCC and PF plants, it would be useful to see how the Operational Inflexibility Cost (OIC) changes.

Figure 6 shows the OIC considering different power generation technologies. As it can be seen, the PF plant has the highest OIC for each fuel price.

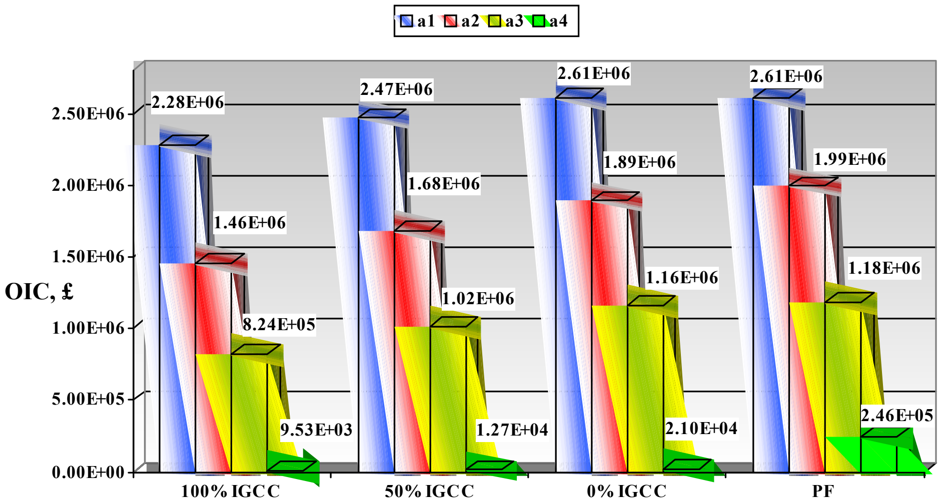


Figure 6: Operational Inflexibility Cost (OIC) per year for each power generation technology using different fuel prices; a1 = 2.2 £/GJ, a2 = 1.8 £/GJ, a3 = 1.4 £/GJ and a4 = 1.0 £/GJ. Months with a profit loss have been considered.

Observing the OIC for IGCC plants and PF plant, it is concluded that generally, the higher the fuel price, the smaller the difference in OIC between IGCC and PF plant.

In terms of the operational inflexibility cost:

PF > 0% IGCC > 50% IGCC > 100% IGCC

It should be noted that while the 0% IGCC has a similar profit variation to the PF plant (they have equal time in which the profit is negative and positive), it also has a higher efficiency, which reduces the OIC.

Figures 7 and 8 are presented in order to indicate the months that the value of OIC is high for the various technologies:

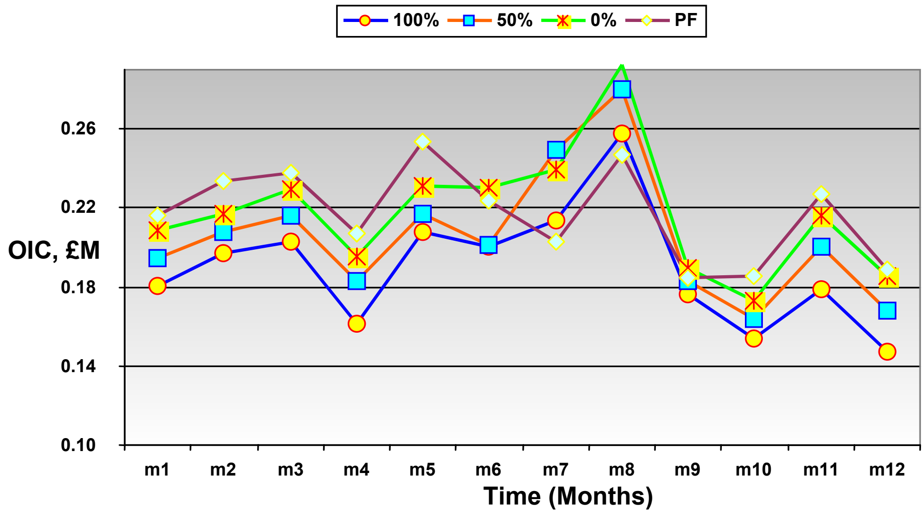


Figure 7: Operational Inflexibility Cost per month with fuel price equal to 2.2 £/GJ. Months with negative profit have been considered.

Figure 7 shows that PF plants have lower OIC than IGCC plants in months m7 and m8. However, it should be noted that during these months the PF plant has negative actual profit (see Figure 4), so the plant will be out of operation during these months.

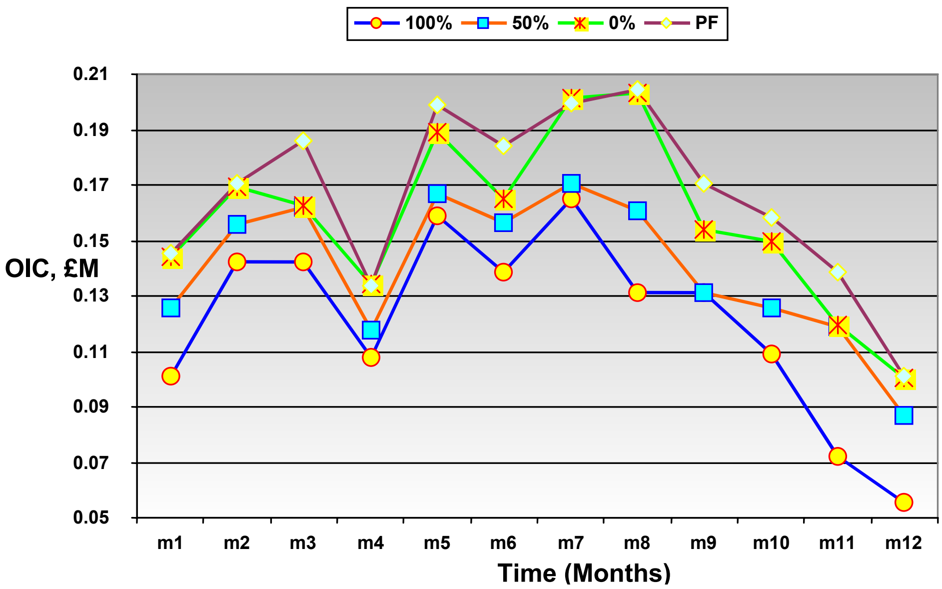


Figure 8: Operational Inflexibility Cost per month considering fuel price equal to 1.8 £/GJ.

The lower fuel price of 1.8 £/GJ affects the OIC for 0% IGCC and PF plant. Figure 8 shows that the OIC is lower during months m7 and m8 and is of similar value for both plants.

Summarising, the % utilisation time, the overall ideal and actual profit are presented in Table 3 for the £2.2/GJ fuel price for the full year.

Table 3: % utilisation, overall ideal and actual profit, OIC for power generation

Parameters	100% IGCC	50% IGCC	0% IGCC	PF
OFF time (%)	36.1	41.9	48.3	45.0
MSG time (%)	9.0	7.6	7.0	7.7
ON time (%)	54.6	49.8	44.1	48.4
Actual profit, £M	11.1	8.71	6.50	8.11
Ideal profit, £M	13.2	10.9	8.74	10.5
OIC, £M	2.18	2.22	2.24	2.43

In terms of the Operational Inflexibility Cost (OIC), 100% integrated IGCC plants have the best performance. The main reason for this is the high efficiency and lower power demand for ASU operation. However, their payback period is higher than PF plants due to the high capital cost. It is known that the capital cost for IGCC plants varies from 1100 $/ kW to 1600 $/ kW whereas PF plants have capital cost equal to ~ 700 $/kW to 800 $/kW. Nevertheless, IGCC plants have the ability for co-production of saleable products (H_2) while PF plants can be used only for power generation. As a result, the overall profit can be increased for IGCC and thus their payback period may be reduced.

Operational scheduling, profit and OIC using a higher coal feed rate is investigated in the following section.

5.1.2 Higher Output Power

Increasing the output power of a plant by burning more fuel is a seemingly obvious method of increasing the profitability of the plant. However the method by which this is carried out is important. It is not meaningful just to assume that the profit from generating x is y and the profit from generating 2x is 2y. Other parameters such as ramp rates and MSG will have a significant influence on plant profitability, with the influence increasing with higher fuel cost.

It is known that gasifying more fuel results in an increase of generated power. The output power affects the power consumption of the ASU. In other words, when the amount of coal feed is increased in order to increase the output power, the ASU requires more power to supply extra oxygen to the gasifier. The higher the coal feed, the higher the amount of oxygen required and consequently the higher the quantity of air to be provided by the ASU.

We will assume that the different power plants use twice as much the initial coal feed to ultimately generate twice the output power. It is assumed that the efficiency, electricity prices and the operation conditions are the same. On the other hand, the power consumed by the ASU will be increased two-fold. In this case, the Operational Inflexibility Cost (OIC) is presented in Figure 9.

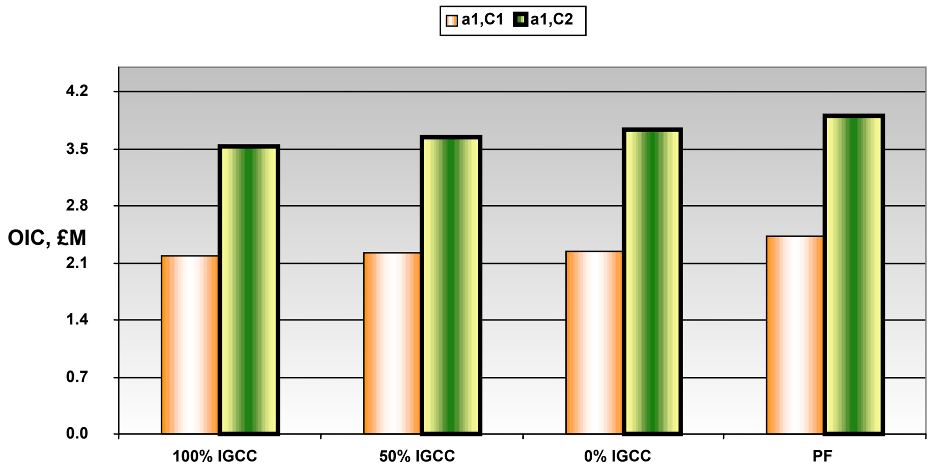


Figure 9: Operational Inflexibility Cost for a1=2.2 £/GJ and coal feed C2 = 2xC1.

It is clear that the ideal profit for twice the output is twice the ideal profit from the initial output (or coal feed rate C_1). The difference is concerned with the actual profit. Specifically, the actual profit for the coal feed C_2 is higher than the actual profit from the coal feed $C_{1,}$ though not two-fold. Furthermore, the OIC for the non-integrated IGCC is higher than that of PF plant when Coal $C_2 = 2xC_1$ is used (and the output power is doubled). This is mainly caused due to the increase of power consumption from the ASU. Table 4 shows the difference in actual profit with respect to the coal feed.

Table 4: The actual profit for 100% integrated IGCC plant using coal inlet $C_2=2*C_1$. $a_1>a_2>a_3>a_4$

Fuel price £/GJ	Expected actual profit, £M[9]	Real actual profit, £M[10]	Difference, £k
a_1	21.9	22.8	909
a_2	31.9	32.6	656
a_3	41.2	41.5	306
a_4	59.1	59.1	0

The real actual profit is obtained from the algorithm for the new coal feed C_2 ($C_2=2*C_1$). The expected actual profit is equal to the actual profit from coal feed C1 multiplied by 2.

The reason for the difference in actual profit is because the model selects the optimal time for partial or total shut down / start up aiming at profit maximisation. Different values for the maximum and minimum power have resulted in different points for start up / shut down. For instance, concerning fuel price A_4, there is no need for start up / shut down since the plant operates mostly to its maximum capacity (i.e. at base load). Thus the difference between estimated and real profit is equal to zero, as there is no difference in their running regime.

In conclusion, it is not appropriate to estimate the profit for a different output power using a reference value of the profit from a lower power output, because the power variation depends on the maximum (full load) and minimum (MSG) power value, as well as the time for these operational changes to occur.

5.2 Hydrogen Co-Production

The methodology in Chapter 4 assumes that power plants are taken off-load when the electricity price is lower than the fuel cost. However, IGCC plants have the opportunity to operate in ON or MSG mode and it never needs to shut down (apart for maintenance reasons) when co-production option is considered. In this case, hydrogen co-production is assumed with a basic selling cost for hydrogen of £3/GJ.

An algorithm has been developed that computes the optimal scheduling for hydrogen production and power generation. The algorithm considers the next 3 cases:

[9] Twice the profit from using the original coal feed rate, C_1
[10] Profit from using coal feed rate C_2 ($2 \times C_1$)

Case 1 (C1) considers that hydrogen is produced **only if** power is generated. This assumption includes start up / shut down options for the whole process (Hydrogen and Power production).

Case 2 (C2) considers that power production occurs when its **profit is positive.** 50% and 0% integrated IGCC plants, hydrogen can be produced even if power is not generated. However, 100% IGCC plants need gas turbine operation for ASU operation. Thus, hydrogen is produced when power is generated even if profit loss takes place due to low electricity price. In this scenario, plant never shuts down / starts up.

Case 3 (C3) considers that power production takes place when the **profit is positive and higher** than the profit from hydrogen yield. This assumptions considers two gas turbines and two ASU but this design does not affect the 0% and 50% IGCC plants, only the 100% IGCC. In this case, the plant never shuts down /starts up.

Figure 10 shows the total profit as well as the profit from hydrogen yield assuming that the sale price of hydrogen is equal to 3 £/GJ.

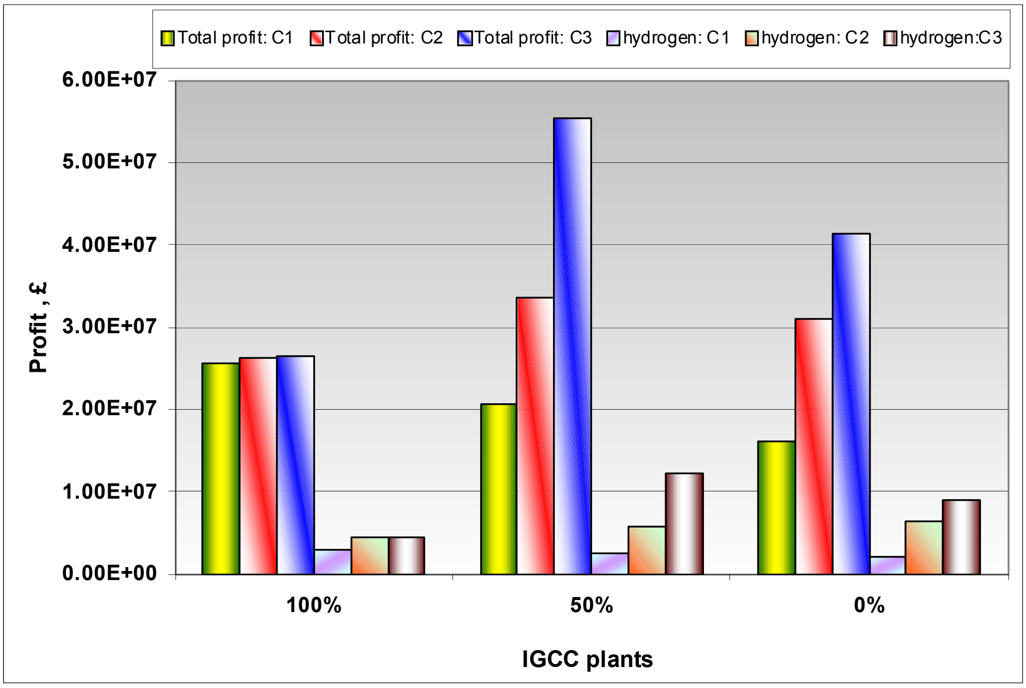


Figure 10: Profit from hydrogen and power co-production considering the three cases (coal fuel price 2.2 £/GJ and hydrogen sale price 3 £/GJ)

Observing Figure 10, it can be said that it is not necessary to have the highest overall efficiency for the hydrogen co-production to be beneficial. The most significant factor is the degree of ASU integration since oxygen has to be provided for coal gasification, so as to produce syngas for hydrogen yield.

Regarding the 0% and 50% integrated IGCC plants; the latter have the higher total profit due to the fact that the profit from power generation is higher than for 0% integration. On the other hand, 0% IGCC plant may have more hydrogen production in relation to the 50% integration plant. The reason for this is the degree of integration as the 0% IGCC plant can gasify any amount of coal since it receives air from the environment alone. On the contrary, partially integrated plants can only gasify half the amount of coal when the GT is not running since they receive only 50% of the total air from the environment (the other 50% form the GT compressor). It has to be noted that the hydrogen yield depends on the length of time that the gasifier is running (which is not necessarily same for 0% and 50% integration), the total cost of power and gasifier conditions.

The following figure demonstrates the benefits of hydrogen co-production:

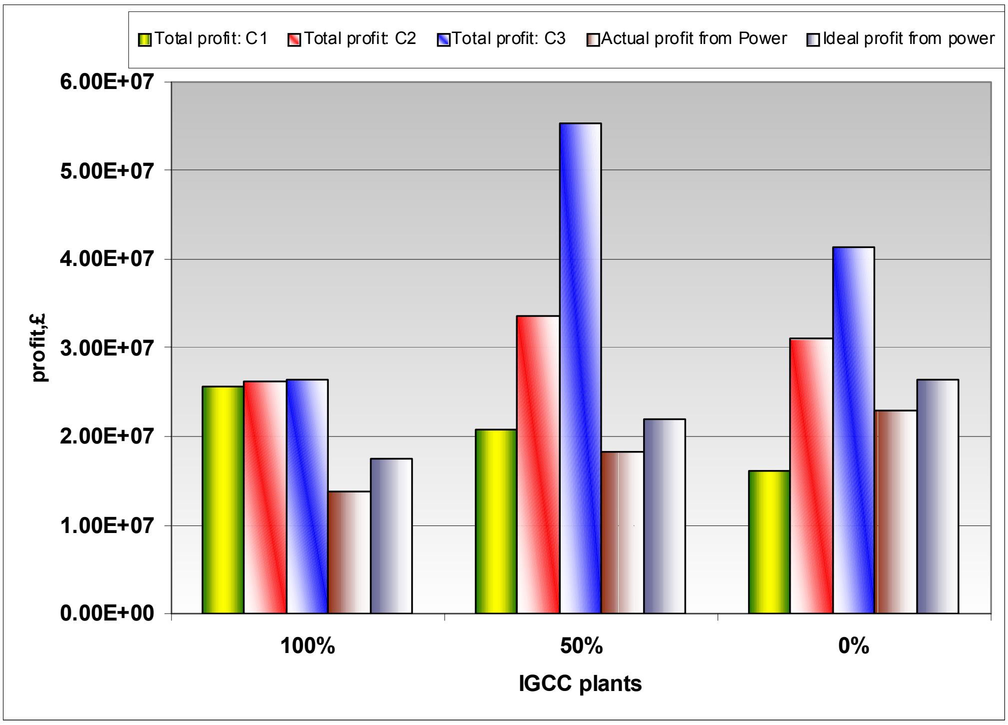


Figure 11: Co-production profit vs. Power generation profit

Figure 11 represents the profit from power generation plants that are fed with a quantity of coal equivalent to the total coal amount that is used for the co-production case. As it can be seen, the 50% integrated

IGCC plant has the highest income increase compared to power generation alone.

The difference with respect to the profit is presented in the following table:

Table 5: Profit (£M) for the different hydrogen production cases

	0%	**50%**	**100%**
Case 1	16.1	20.7	25.5
Case 2	31.0	33.5	26.3
Case 3	41.4	55.3	26.4
Power Generation (500MW) (No H_2)	**13.7**	**18.2**	**23.0**
Difference Case 1	2.39	2.50	2.59
Difference Case 2	17.3	15.3	3.33
Difference Case 3	27.7	37.1	3.48

In case 1 the 100% integrated IGCC has higher profit increase (hydrogen is produced for that time interval with in which power is generated). In case 2, the 0% integrated IGCC has higher profit increase than 50% integrated IGCC. While in case 3, the 50% integrated IGCC has a greater increase in profit than 0% IGCC.

The best scenario for profit is based on case 3. Accordingly, the 50% integrated IGCC plant should be selected for the hydrogen co-production (see figure 12 where 50% IGCC has the shortest payback time).

It is noted that the hydrogen yield depends on its % mole in syngas. In other words, fuels with high % mole H_2 in syngas should be selected as should gasification conditions that encourage the hydrogen production.

Figure 12 shows how the payback period changes when hydrogen co-production is assumed. The actual payback period (PP) is based on the profit of power generation when the total amount of coal (coal for hydrogen and power production) is used only for producing power. Even if the power plant could operate according to its ideal condition, the ideal PP is greater than the PP from hydrogen yield.

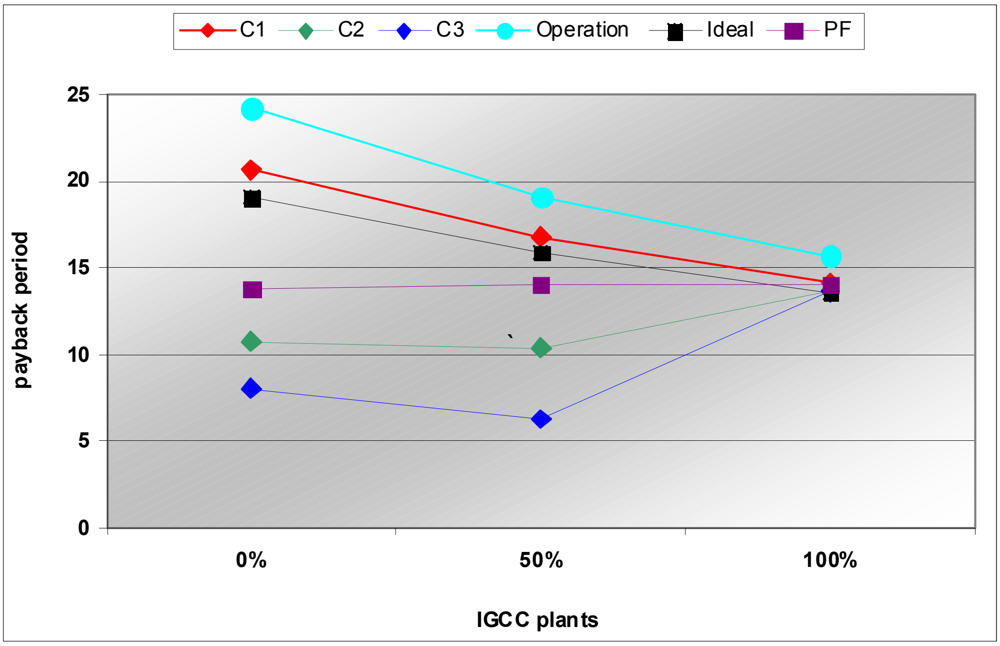


Figure 12: Payback period (years) related with Hydrogen Co-production

The information that Figure 12 is based on assumes that the capital cost for Hydrogen Process Unit is equal to 10% of the capital cost for power generation. However, storage and transport costs for hydrogen yield have not been considered.

In this case, a general approach regarding the total cost for hydrogen co-production can be developed. Knowing the total income and the payback period is lower than that of power generation alone, an upper bound with respect to the capital cost for hydrogen production can be produced.

For example, consider that the IGCC plant with hydrogen co-production needs to have a payback period equal to that of PF plant. The upper value for the spending cost concerning the HPU is given by equation 1:

Capital cost for HPU=(Total income)*PP-Capital cost for Power generation (1)

Thus, knowing the rate of hydrogen generation, the capital cost for the HPU, storage and transport can be estimated. If the estimated capital cost is greater than the capital cost of equation 1, then it is not necessary to use the co-production option.

The preceding observations show that, 50% integrated IGCC plants should be used for power generation and hydrogen co-production since they provide the maximum overall profit and they have the minimum payback period. For the specific hydrogen electricity price, partial integrated IGCC plants have payback period even less than the PF plant.

It should be noted that at present there is not an established market for the collection of hydrogen from a hydrogen production site in the UK, though if there were large quantities of hydrogen available then it would be reasonable to assume that a market would be created.

The price of 3£/GJ used is based on the fact that gas prices are in the region of £2/GJ to £2.40/GJ (and set to rise further) and £3/GK seem to be a reasonable price as hydrogen is a better fuel and would therefore command a higher price. If, however, the price where too high then it would be cheaper to convert natural gas to hydrogen and use that source instead.

5.3 Maintenance Scheduling

The model for the maintenance scheduling considers the production loss due to plant unavailability to satisfy the power demand as a result of maintenance actions. In our case the production loss varies since it is dependent on the electricity price. A model has been developed that provides the number of maintenance policies per year taking into account that the reliability function has to be greater than a threshold value for a plant to be operable (this value has been arbitrarily assigned). Additionally, it provides the profit loss due to corrective and preventive maintenance graphically so that decisions can be made about in which period the maintenance operation will be applied.

A case study is illustrated in order to see explicitly how the model works:

Suppose that the plant consists of two main blocks. The blocks 1 and 2 are series connected. This means that when one block does not operate (due to failure or repair action), the other can not operate without an alternative feed. For example, if block 2 does not operate, then the block 1 cannot operate for 100%-integrated design. The reason for that response is due to the fact that the gas turbine provides air to ASU. Without gas turbine operation, there is no power generation or oxygen production from ASU. Thus, the gasifier (block 1) can not operate since there is no oxygen supply.

The Mean Time Between Failure (MTBF) and the time for corrective / preventive repair policies have been obtained from data related with previous corrective maintenance actions. This data is presented in Table 6.

Table 6: Data regarding the MTBF time and the repair time for corrective and preventive action

Parameters	Block 1[11]	Block 2[12]
MTBF (days)	950	1100
Repair time for corrective action (days)	25	19
Repair time for preventive action (days)	18	15

The profit loss due to corrective and preventive maintenance action is calculated from the algorithm. The results are presented in Figures 13 and 14.

The figures represent the profit loss from the preventive and corrective maintenance. It should be noted that corrective maintenance occurs at unscheduled time period since it is performed only when the components fail. In contrast, the preventive maintenance is a scheduling action aiming the improvement of the reliability function so as to minimise the possibility for failure. The problem is WHEN maintenance action should be executed so as to have more available income.

As it can be observed in Figures 13 and 14, the profit loss due to unplanned failure is high at the beginning and at the end of the time horizon, due to electricity prices being higher in during colder weather at the beginning and end of the year. Considering that the reliability function is high at the beginning of time horizon (which means that there is a small possibility for plant failure) these periods may be ignored (as plant failure is unlikely). Conversely, the later time intervals in the year cannot be ignored since the reliability value is decreased. In other words the possibility for plant failure increases. Thus, maintenance action should be executed based on the following objectives:

1. Minimising the possibility for plant failure in the later time intervals in order to avoid the indicated profit loss.

2. Suggesting the optimal time interval for repair aiming at profit loss minimisation - due to the downtime of the plant - and the less number of maintenance operations – because of the indirect cost for repair action (e.g. staff).

[11] Gasifier, ASU and gas cleaning plant
[12] Gas turbine, steam turbine and HRSG

3. The system's reliability function has to satisfy its threshold value at the end of the time horizon.

In order to find the appropriate time period for maintenance, the profit loss resulting from preventive maintenance is observed. Then, the time interval for repair action is selected based on the following observations:

1. If preventive actions are applied in early time periods then there is the possibility to have the reliability function lower than the threshold towards the end of the year. Therefore, more actions would need to be applied in order to have a satisfactory reliability value at the end of the time horizon (a year in the example). However, additional repair actions result in additional maintenance cost due to the associated labour costs.

2. If preventive actions are selected in later time periods, there is the possibility for plant failure before maintenance is carried out. In that case, the plant undergoes corrective maintenance action, resulting in a higher ultimate cost.

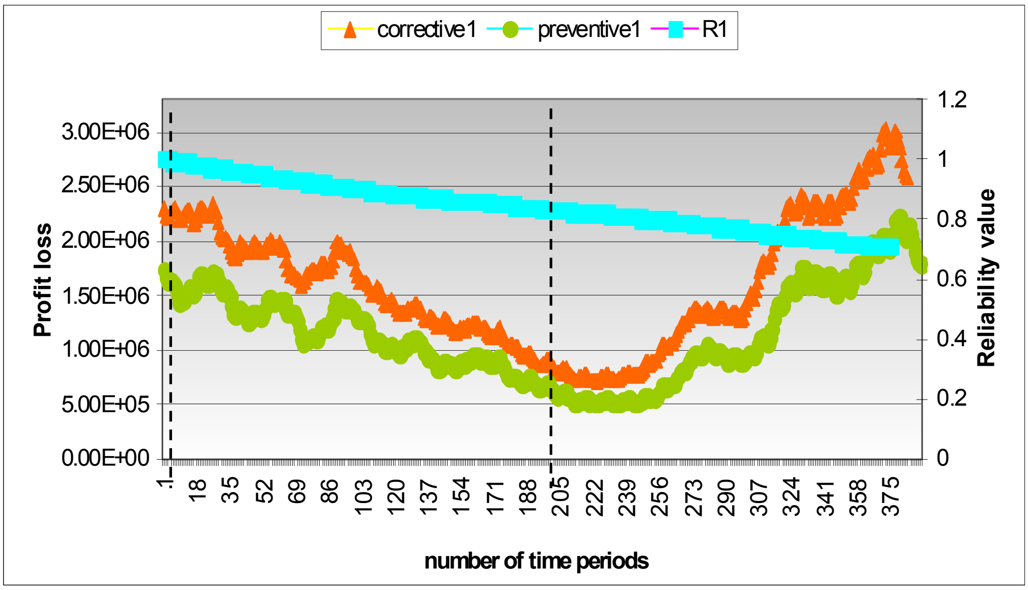


Figure 13: Profit loss (£) due to corrective and preventive maintenance for Block 1 for 50% integrated IGCC plant

Figure 14 represents the profit loss from the corrective and preventive maintenance in Block 2. Observing Figures 13 and 14, it can be seen that the maximum and minimum profit loss occurs at the same time for Blocks 1 and 2, which reflects the electricity price. The only difference is the value of profit loss and reliability function (the latter depends on the MTBF time for each Block).

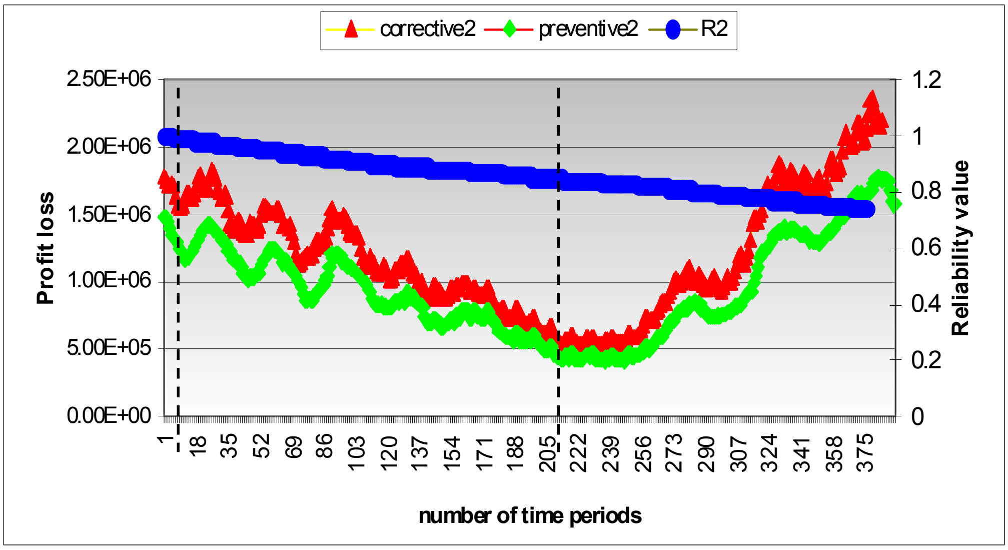


Figure 14: Profit loss (£) due to corrective and preventive maintenance for Block 2 for 50% integrated IGCC

The model suggests the optimal point for maintenance action considering the criterion 2. According to it, the optimal time to repair is presented in Table 7.

Table 7: Profit loss with respect to Criterion 1 and 2 for 50% integrated IGCC plant.

Criterion 1	**Block 1**[13]	**Block 2**[14]
Time period (day)	143	152
Reliability	0.87	0.88
Profit loss (£k/yr.)	818	692
Total loss (£M)	**1.51**	
Criterion 2	**Block 1**	**Block 2**
Time period (day)	213	235
Reliability	0.82	0.83
Profit loss (£k/yr.)	504	418
Total loss (£M)	**0.922**	
Net income (£M)	**25.3**	

[13] Gasifier, ASU and gas cleaning plant
[14] Gas turbine, steam turbine and HRSG

Maintenance is scheduled for both blocks 1 and 2 to minimise the lost profit. Though ideally this may be at different times, practically speaking the maintenance will be carried out simultaneously minimise plant downtime. Using different values for power price, time duration for power generation and fuel cost, different profit loss will be observed. In spite of this, if the power price during the summer months is less than the other months, the typical time period during which it is most beneficial to carry out maintenance will not change. As a consequence, the optimal time interval for maintenance is during periods of low electricity price (summer months). Specifically, it will be that time interval with the minimum accumulated profit loss during the repair time.

As it can be seen from the Table 7, when the reliability function is high, a cost equivalent to £588,000 has to be considered (the extra profit that would be lost if maintenance were to be performed according to criterion 1 rather then criterion 2). Of course, when the electricity price is higher then the cost will be increased. The other factors that affect the previous cost are the MTBF time as well as the time for corrective/preventive maintenance.

For 100% integrated plant the profit loss due to maintenance operation increases since it realises more profit when it operates. However, the difference between the income from operation and the maintenance cost (net income including maintenance actions) is observed to be higher for 100% integrated plant (see Table 8).

Table 8: Profit loss with respect to Criterion 1 and 2 for 100% integrated IGCC plant.

Criterion 2	**Block 1**	**Block 2**
Time period	213	235
Reliability	0.82	0.83
Profit loss (£k/yr.)	603.33	506.31
Total loss (£M)	**1.10964**	
Net income (£M)	**28.0**	

It has to be noted that a basic assumption used in the model is that it is not possible to repair both blocks at the same time due to availability of the staff, though in reality maintenance will be carried out simultaneously to minimise plant downtime (and lost profit).

Summarising, 100% integrated IGCC plants have the best performance with respect to the other types of IGCC plants even when maintenance cost has been included for the calculation of the overall profit. The net income for the 100% integrated plant is greater than for the 50%

integrated plant even though the profit losses are greater as the efficiency of the plant is higher. This results in higher profits for the period when the plant is running, which more than offset the profit that is lost due to maintenance.

6 CONCLUSIONS

6.1 Operational Scheduling

The model provides the optimal running strategy for power plants. Explicitly, monthly graphical estimation with respect to the profit and the Operational Inflexibility Cost is provided so that decisions can be made concerning how a plant is to operate. Secondly, the operation mode for each time period is suggested, in order to maximise profit.

Using the figures that are related with the Operational Inflexibility Cost, the following benefits are obtained:

a. A graphical approach for the profitability of different power plants on a monthly basis (though you could apply the method using any sensible time period) has been developed. Thus, it is known which plant (in a varied portfolio) would be more beneficial to operate for each period so as to increase the total profit and reduce the OIC.

b. You can decide in which month(s) or period(s), not to operate so as to have lower OIC and consequently lower profit loss.

In terms of power generation technologies, the fully integrated IGCC has the best overall performance (excluding fixed costs). It is concluded that the higher the fuel price, the better the operation of IGCC compared with PF plant as the cost of electricity is lower and it can therefore run base load more often. In terms of the degree of integration, the fully integrated IGCC presents better performance rather than the non-integrated and the partially integrated IGCC plant. The reason is the higher efficiency and the lower power consumption from the ASU as air is supplied from the GT compressor rather than the GT exhaust. As far as the overall operation of non-integrated IGCC plants is concerned, the fuel price affects mainly their profitability & therefore their operation.

6.2 Hydrogen Co-Production

The co-production of hydrogen is not affected by the efficiency, only by the degree of ASU integration. Thus, although the 100% integrated IGCC plant may be appropriate for power generation, the 0% and 50%

integrated IGCC plants are ideal for the hydrogen co-production, as hydrogen can be produced when power is not generated. The selection between 0% and 50% IGCC plants depends on the hydrogen price and the electricity price.

The co-production option results increase in income though this is not the only criterion for its selection. Capital cost for the Hydrogen Process Units (HPU), storage and transport of hydrogen should be taken into account. An upper bound for the capital cost that should be spent for the additional components is obtained from the model to ensure that payback is no longer than for power generation alone.

6.3 Maintenance Scheduling

The maintenance scheduling is based on graphical approach of the production loss due to corrective and preventive maintenance policies. The aim of the preventive maintenance is to repair the components so as to reduce the possibility for plant failure when the production loss due to plant unavailability is the maximum.

The developed algorithm suggests the optimal number of maintenance actions per year so as to have reliability above a certain threshold at the end of the period in question. What is more, the optimal time for maintenance actions are suggested considering the criterion for profit loss minimisation. This is shown to be during the summer months when electricity prices (and therefore potential profit) are low.

Additionally, the following advantages appear:

1. In the case that component reliability information is used, instead of for a block of plant, identification of the component with the maximum profit loss can result. Thus, decisions can be made, if it is necessary to have back up components held in stock that will be able to operate while the first is repaired. In this case, additional capital cost for the back up components needs to be taken into account

2. Managers can decide when to schedule maintenance, considering maximum profitability or maximum reliability.

6.4 Other Issues

The overall profitability of the plant is more dependent on the base capability of the plant than its flexibility. The benefits of gasification plants such as their superior efficiency, lower emissions and fuel flexibility are likely to affect the long term profit to a greater extent if the reliability of the component plants are proven.

The higher the efficiency of the plant, the less relevant operational flexibility becomes, since high efficiency plant will run base load more often and for longer than lower efficiency plant (if all other factors are equal, such as fuel price, etc). The higher efficiencies of highly integrated IGCCs can offset the cost associated with the longer start up times of the gasifier, due to the increased likelihood of base load running).

7 REFERENCES

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