CHAPTER 6
CALCULATION AND INTERPRETATION OF RESULTS

6. CALCULATION AND INTERPRETATION OF RESULTS

After the monitoring which was performed during testing, the calculation of results should be seen as a three tier process:

- The primary process was the initial accumulation of data which was either the manual recording of, values such as the total air flow parameters by means of manometer fluid positions, or automatically recorded data from the SICOMP 70 process computer as described in Chapter 4, Table 4.5. The primary calculation of data consisted mainly of the averaging and totalising of recorder and manually monitored values according to the "integrity" criteria as discussed in Chapter 4.5.

- The secondary process was where all these monitored and calculated values of the parameters were developed to such a stage that they could be accumulated as engineering values and displayed as data in spreadsheets. These data files are voluminous due to the character of the tests and plant involved. It is not practically feasible to display all these calculated data, which consists of three spreadsheets, called Revision (Rev.) 0, 1 and 2, for the tests performed on each of the three coal qualities. Thus, instead of nine spreadsheets of data, a selection of the important parameters of Rev. 2 (final calculated results) for each of the Low, Spec. and High grade coal (three spreadsheets in total) are shown in Appendices F, G and H respectively. The methodology of how the final results were achieved via the three stages of Rev. 0, 1 and 2 will be explained in Section 6.1. Where applicable, data of Rev. 0 and 1 will also be shown in graphical form together with that of Rev. 2 to illustrate the relative difference. The tables in consecutive order in e.g., Appendix F consist of the following tests:

Table F.1: 630 MW tests

Table F.2: 550 MW tests

Table F.3: 500 MW tests

Table F.4: 450 MW tests

Table F.5: 400 MW tests

Appendices G and H contain a similar sequence of tables. For each one of these loads the columns appearing on one page consist of the parameter, its units and six different air flows' test values performed on one day, as explained in Chapter 4 (the highest air flow test first, with the lowest air flow test for the day's testing in the last column). The parameters in these data files are grouped into the following categories:

Flue gas analysis

Air and flue gas properties

Volumetric - Gravimetric back-end gas reconciliation

Coal quantity and quality (air dried and as received)

Milling plant

Working fluid conditions

Condenser performance

Electrical parameters

STEP output parameters

In the following sections, the discussion will justify of the method of calculation of results, with special reference to the sample calculations in Appendices A and B where necessary, and interpretations with trending graphs where applicable. In this chapter attention will be concentrated on the concepts, philosophies and techniques involved. Some of the detail of the calculations is contained in the appendices mentioned, the purpose being not to confuse the logical flow of concepts with too much detail.

- The tertiary process was where the highest order of parameters were calculated and interpreted. Generally these were the parameters that included the final Thermal Efficiencies and Optimum Air Flows that led to the eventual recommendations in Chapter 7 and the customisation of the STEP program. These comprised the parameters on which decisions were made and technical philosophies formed, which included the compiling of Operational Procedures or the revision of existing ones, as well as Statutory formulations for Lethabo Power Station.

In general, it should be noted that many of the graphs in Chapters 6 and 7 are not X-Y graphs, but are trend graphs were the X - axis divisions are only consecutive tests, performed from high to low air flow for each day, thus having no scale.

6.1 DIRECT EFFICIENCY CALCULATION METHOD

This section initially describes the secondary calculation process. The internationally accepted norm (as is the case in ESKOM, RSA) is to employ only the indirect or losses method in performance testing calculations, often by means of BS 2885. The main reason being the inaccuracy of measuring the coal mass flow and CV determination needed in the direct method. In the coal mass flow a reasonably high degree of accuracy can be obtained with the volumetric feeder calibration (Appendix A, Sample calculation A.5), but the density and representivety of the sampled coal renders the mass flow and CV determination too inaccurate for efficiency calculations.

This presented a problem when reconciling the calculations of Excess Air Reduction tests[5] performed on Lethabo Unit 1 prior to these tests, utilising the traditional BS 2885, which showed a 50 t/h error in coal flow (out of a 400t/h total coal flow) on the direct side when a STEP program simulation was performed with the same data. BS 2885 mainly emphasises the indirect method, whilst STEP utilises both the direct and indirect calculation methods, forcing reconciliation via the minimising or explanation of the unaccountable losses (see Appendix I for the explanation of the STEP methodology). Mainly due to the discrepancy exposed by the process, the recommendations could not be implemented. It should be pointed out that the discrepancy did not occur due to human error or faulty instrumentation etc., but rather a deficiency in the philosophy of using the indirect losses method only for this purpose. This gave rise to the author's identification of a need and the quest to develop a testing and calculation method that would also cross-check the results with the direct side, since the indirect side method alone proved not to take all influences into account. Also, the final result of this project relies on credible overall unit efficiencies as the main criterion to determine the optimum combustion air flow. The indirect method alone is thus not adequate, since efficiency of the unit is not an output thereof. The inconsistency of coal CV determination with the bomb calorimeter (as will be seen in the comparative results) also contributes to the problem. The methodology of the technique explained in this section addressed these problems.

This method can be termed a "Three criteria Back-end gas mass balance technique". Broadly, this means that the mass flow of the flue gas at the boiler back-end was determined in three different ways and each must be equal, for mass-energy balance to have been achieved. The density of the coal was then back-calculated to satisfy this condition and that produced a coal mass flow derived from the volumetric feeder integrator readings. A special CV calculation formula was developed and together with the units sent out, an efficiency was obtained. Thereafter, these trends were refined by means of curve fitting techniques, interpolation and other cross-checking criteria (Section 6.2) to obtain the optimum combustion air flow and other parameters corresponding to the highest overall thermal efficiency for each coal quality at each load.

These three-criteria spreadsheets, Rev. 0, 1 and 2, produced the required mass-energy balance values by forcing the applicable parameters (e.g. back-end gas mass flows) to converge by means of macros operating various iterations in the spreadsheets (e.g. Appendix A, Sample calculations A.3.4 and A.7). This will be explained in the sections below. A final point to mention in general is the interpolation capability in the trends obtained graphically, due to large amount of sets of data of these tests. This aspect was used to identify and correct erroneous values caused by minor problem with instrumentation.

6.1.1 Revision 0 data files

Initially a Rev. 0 data file was compiled for each of the Low, Spec. and High grade coal tests. A characteristic of the Rev. 0 spreadsheets which distinguishes them most from Rev. 1 and 2, is that they display the values of the parameters in the most basic form as measured, instrument errors etc. not corrected. The iterations were allowed to operate after a hypothetical coal density of 1000 kg/m^3 was inserted for all coal qualities as a point of departure for this first iteration (Rev. 0). The construction of the spreadsheet parameters as per the above mentioned categories are as follows:

Flue gas analysis:

Flue gas oxygen was measured after the economiser as wet volumetric (see Chapter 4.7.6) and air heater outlet as dry volumetric (see

Chapter 4.7.7). CO, NO_x, SO_2, CO_2 and O_2 were measured with the mobile analytical facility at the ID fan discharge as dry volumetric (see Chapter 4.7.8). CO was measured with an infra- red, cross-duct scanner as well. All the readings were taken at the pre-determined reference points and weighted according to the factors obtained from the traverses performed (see Appendix B). All these gas analysis values were converted from wet to dry and from volumetric to gravimetric for calculations where applicable (see Appendix A, Sample calculation A.3.1). They were mostly displayed as volumetric percentages in the spreadsheets since that is the mode on the panel indication. The associated Ostwald diagram values of CO_2 and O_2 were values obtained from the revised Ostwald diagram (see Appendix A, Sample calculation A.6).

Air and flue gas properties:
Many of the parameters measured in this category do not require involved explanations, since they are straight forward and used in the determination of other parameters, which can be seen in the calculations of e.g. Appendix A. Only certain parameters in this category will be discussed.

The air heater gas outlet temperatures were measured according to the same weighting factors and measuring points determined by gas duct traverses as the oxygen (see Chapter 4.7.7 and Appendix B). The no-leakage air heater outlet temperature was calculated from the measured air heater outlet temperatures and the oxygen difference before and after the air heater according to the method described in

Appendix A, Sample calculation A.3.2. This is to predict the real temperature, had there been no air in-leakage, thereby creating a fixed basis of reference. The impact thereof would otherwise give too low a dry flue gas loss which would be a false value, therefore this modification was also built into the STEP program (see Appendix I). The actual dry flue gas loss was calculated in the same way as in the STEP program:

$$Q = m\ c_p\ (T_H - T_L)$$

This is the typical equation where the heat given off by the flue gas must equal the heat taken up by the water and steam. The remainder of the heat not given of by the flue gas (to the steam or air in regenerative air heaters) is the dry flue gas loss. The resulting changes in target values on the indirect side of the STEP program, which deals with accountable losses, could lead to future Second Law analyses.

Important to note is that it is the difference in temperatures (compensated air heater outlet and air heater inlet) that matters in air heater evaluation, not only the air heater outlet temperature. The temperatures used in the dry flue gas loss formula above however are the FD inlet and the air heater outlet temperatures. Important is the fact that the increased mass flow of the flue gas caused by excess combustion air flow has a greater influence on the dry flue gas loss value than the temperature difference in the above equation. The

ID fan discharge temperatures were measured directly by the mobile analytical facility as LH and RH values, which were averaged with the mentioned weighting factors (Appendix B).

The moisture in flue gas was needed for each and every test since the back-end gas mass flows had to be calculated on a dry ash free (DAF) basis. The detailed explanation of how this was determined and calculated is given in Appendix A, Sample calculation A.9.

The total air flow at the measuring aerofoils was calculated as the total of the LH and RH side as in Appendix A, Sample calculation A.2 is from basic principles by means of manometer fluid differentials, compensated for moisture in air and using the specified C_d factors. This was performed once per test mainly to obtain the correction factors for the eqivalent continuous reading from the SICOMP computer.

The "Air Flow Total" in the table was obtained by applying that correction factor to the SICOMP reading, adding the predetermined leakage at the aerofoil casing (measured with a vane anemometer), the burner core air and mill seal air leakage. The burner core air leakage proved to be a constant at all loads (11.93 kg/s) and was also determined by means of a vane anemometer. All the burners contributed to this in-leakage continiously, whether the mill serving its row of burners were in service or not, since the leakage was a function of the differential pressure between the furnace and atmosphere. The mill seal air in-leakage was determined by pitot-tube traverse and cross-checked by vane anemometer and proved to be a constant (3.657 kg/s per mill) multiplied by the number of mills in service. The combustion air was the quantity produced after the air heater leakage was subtracted from this total air supplied. This was the quantity that contributed to the combustion process that could be measured (including its measurable leakages). The Rev. 0 Air Flow Total and Combustion Air can be seen in Figure 6.1 for all tests.

There was a quantity of air that participated in the combustion process that could not directly be measured, i.e. the furnace in-leakage. This quantity comprised of the leakage between all the sootblower lances and carriages, the carriages and furnace walls, the purging air of the wall blowers and the eight pyrometers, the leakage between the pyrometers and the furnace wall, the thirty six burner inspection doors seals and the many furnace inspection doors. This quantity was determined by means of comparison between pitot-tube traverses at the economiser outlet (including the gases originating from the combustion of coal) and all the air supplied including the measurable in-leakages as mentioned above. The value was also evaluated against the result of this iterative calculation process (Rev. 2) and compared favourably with the difference between the stoichiometric or theoretical air (calculated from a different source) and the tests with the minimum air flows (measured as above) approaching stoichiometric value. This can be seen later on the air flow graph Rev. 2. The estimated furnace leakage amounted to a constant 35 kg/s. An explanation can also be seen in Appendix A, Sample calculation A.3.4.

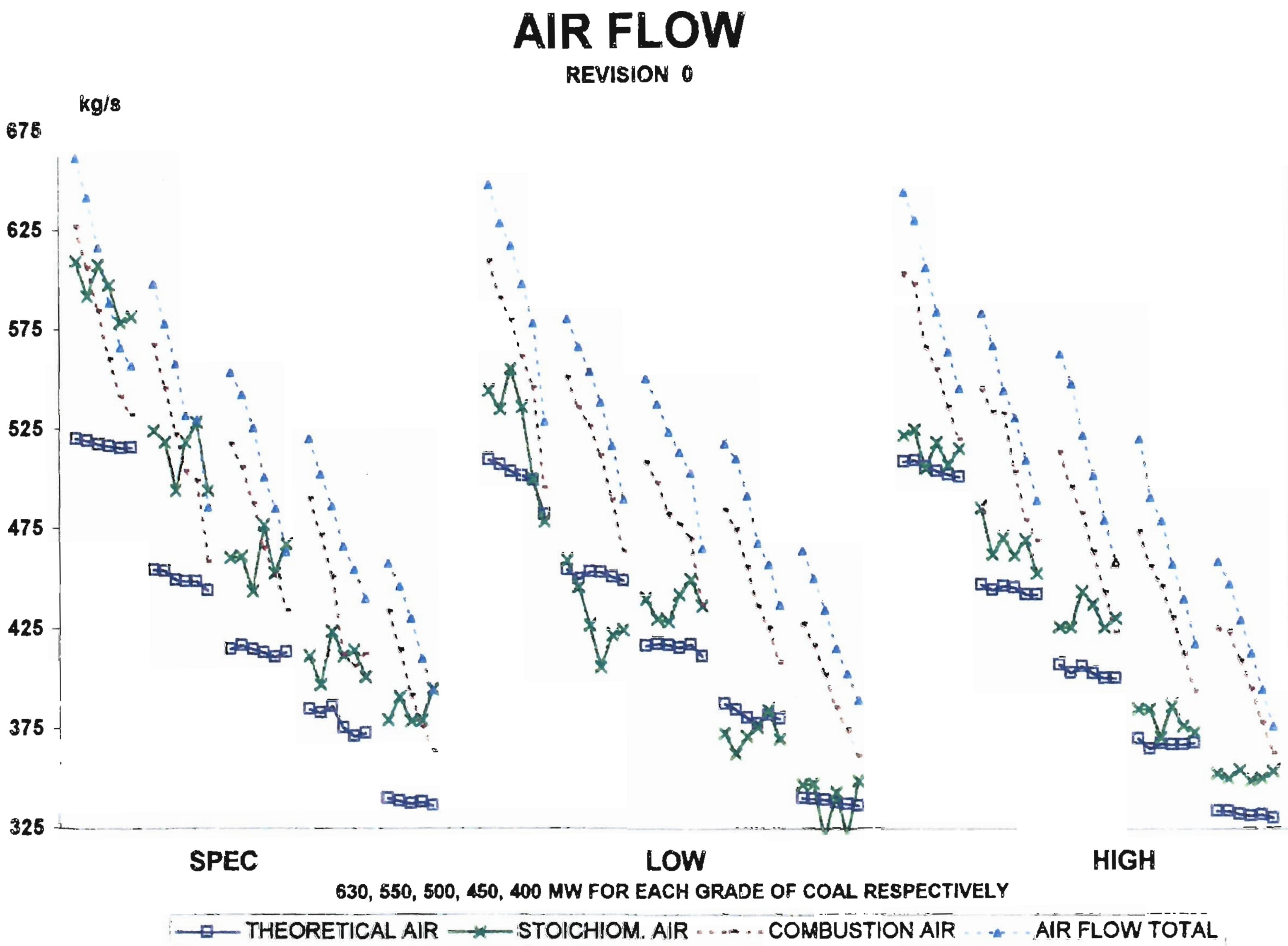


Figure 6.1: AIR FLOW (Rev. 0)

The calculated furnace oxygen is a back-calculated value from the economiser outlet oxygen once the furnace in-leakage was known, similarly to the calculation of air heater leakage, stoichiometric and theoretical air utilising the newly derived formulae, as in Appendix A, Sample calculations A.3.3 and A.3.4. (These formulae are gravimetric or mass based and were found to be more accurate than the traditional volumetric formulae which proved to be inadequate.) The furnace oxygen can not be measured since it does not appear in a localised plane (due to the leakage points being widely spread over the furnace). It is not a physical entity, but the value representing that oxygen is intended for spreadsheet calculation. Since all furnaces do not leak equally and a furnace leakage can vary with time, this was a more absolute reference than economiser oxygen. These calculations were based thereon, especially in the calculation of the theoretical air from the formulae in the above mentioned sample calculations. The furnace oxygen was the oxygen value used and not the economiser outlet oxygen.

Some clarification of terminology in this document is needed, since the theoretical air is the equivalent of the stoichiometric air, but calculated from the air flow and oxygen side as in Appendix A, Sample calculation A.3.3. The stoichiometric air is the same quantity, but calculated from the chemical equations used in the combustion of coal (Appendix A, Sample calculation A.1). This is one of the important aspects in the gas balance technique utilised here. In Rev. 1 and 2, coal density and other parameters are iterated to ensure these two values are equal, calculated from different sides with totally different parameters. It can be seen that the theoretical and stoichiometric air were not equal in Rev. 0 (Figure 6.1). Especially the stoichiometric air has an erratic trend.

It was found necessary to determine the air heater leakage by means of an iteration. This calculation is one of the iterations performed automatically by the macro in the spreadsheets. Whenever any parameter in the spreadsheet was changed (during the manipulations of Rev. 0 and 1), the air heater leakage iteration would produce a new air heater leakage that would satisfy the new conditions. The Air heater leakage iteration methodology is extensively explained in (Appendix A, Sample calculation A.3.4). Important to note is that with this method this leakage is obtained in terms of kg/s, not as a fraction of the flue gas.

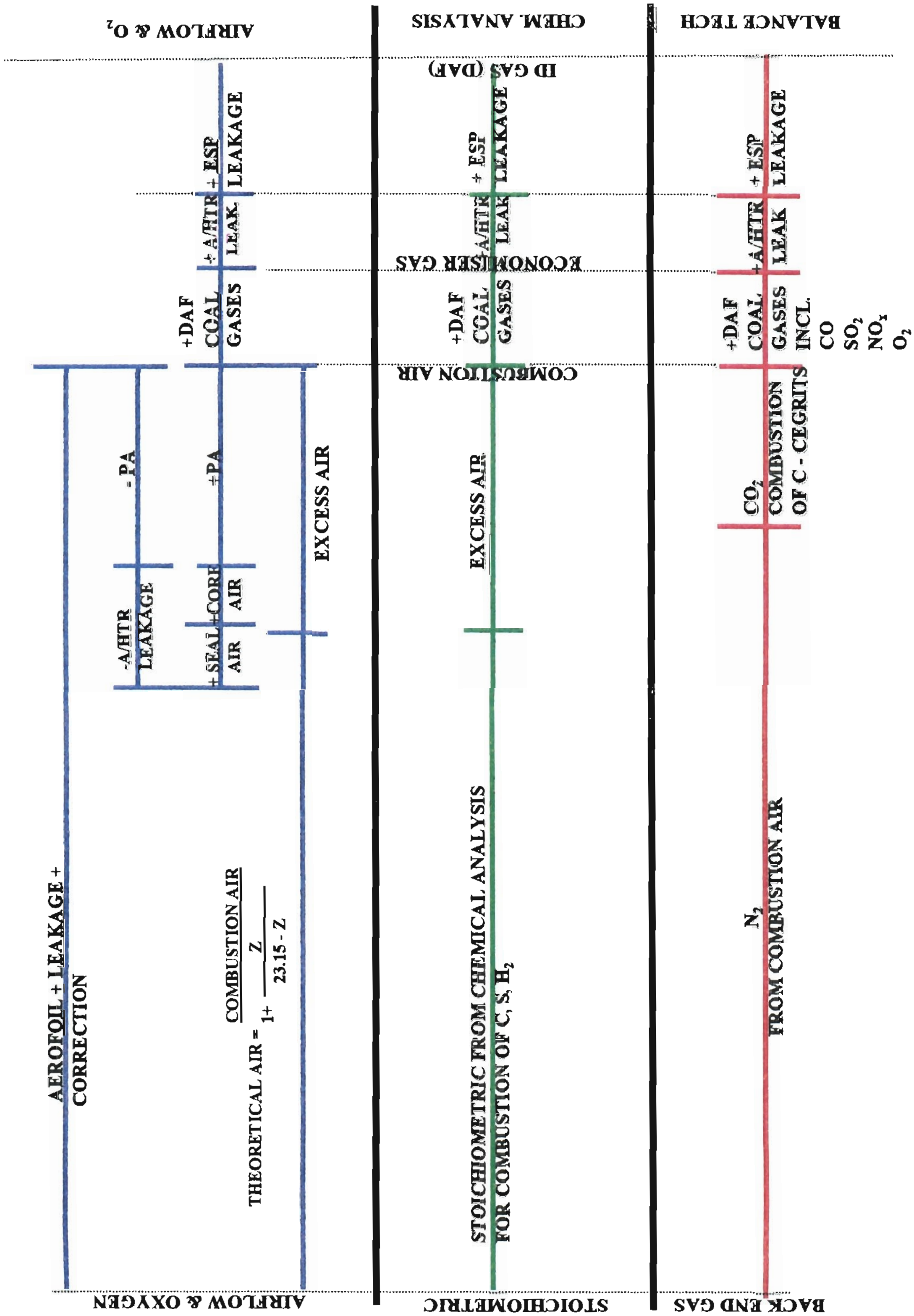
After Rev 0 and 1, this air heater leakage produced a trend which could then be fixed as a function for each load for each coal quality, which will be shown graphically in the discussion of Rev 2. Similarly, the electrostatic precipitator in-leakage was determined with the equivalent formulae and trends as a function of load and coal quality. The reason that some of these in-leakages (air heater and precipitator) had slightly different values for different coal qualities at the same load (and sometimes total air flow), was due to the fact that the number of mills in service were different. This resulted in different ratios of primary and secondary air flows for the same total air flow causing other differential pressures over especially the secondary air heaters. The excess air was calculated as in (Appendix A, Sample calculation A.1).

Figure A.4 in and the explanation involving Table A.1 in Sample calculation A.3.4, Appendix A, provides a comprehensive picture of how all the air flows, in-leakages, air heater leakage and gases are added or subtracted to eventually produce the economiser and air heater outlet gas quantities (DAF).

The calculation of the back-end (ID fan) gas quantities on a DAF basis in the three different ways mentioned above, can best be explained whilst viewing Figure 6.2. The diagram is divided in three sections when viewed in landscape mode. The air flow, gases etc., diagramatically add up from left to right to eventually produce the total ID or back-end gas quantities.

The first criterion by which the ID gas was calculated is from the air flow and oxygen side. The respective additions and subtractions of total measured air flows and leakages (as explained above and indicated in the figure) eventually produce the combustion air. This combustion air must also be equal to the theoretical plus excess air, as indicated in Figure 6.2. The theoretical air is obtained from the indicated formula (and its derivitives as explained in Appendix A.3.3).

Figure 6.2: THREE-CRITERIA BACK-END GAS BALANCE TECHNIQUE



The addition of the DAF gases resulting from the combustion of coal (Appendix A, Sample calculations A.1 and A.3.1), the air heater leakage and the electrostatic precipitator (ESP) in-leakage totalises the ID gas according to these criteria. This is called "ID Gas (DAF)" and was considered as the most reliable, representative and accurate criterion and was used as "anchoring pivot" toward which the other two criteria were iterated to converge. The formula in Sample calculation A.3.3 is very important for eventually calculating the final efficiency:

$$\text{Theoretical air} = \frac{\text{Total measured Air Flow} - \text{Air heater leakage}}{\left(1 + \dfrac{z}{23.15 - z}\right)}$$

The reasons why this air flow and oxygen criterion were regarded as so important and reliable are firstly its representivity. The whole stream of air flow is "sampled" when the mass flow is determined by manometer and the oxygen sampling matrix also produces a representivity much greater than coal sampling (for CV and density determination), etc. Secondly, the effort and methodologies that went into the measurement, instrumentation and integrity of these values are equalled by neither of the other two criteria (refer Appendix A.2, A.3.3, A.3.4 and Chapter 4.7). The reason why this criterion, due to its accuracy, was not sufficient as only one in the process, is because the overall unit efficiency can not be calculated from this alone. The energy input (coal mass flow, CV etc.) was necessary and obtained from the second criteria.

The second criterion for calculating the ID gas mass flow was done by means of the chemical or stoichiometric equations (Appendix A.1 and A.3.1). Refinements were brought into the calculation to cater for e.g., incomplete combustion. The unburnt carbon in ash was firstly subtracted from the total carbon. The remainder of the carbon then initially produced CO (incomplete combustion) where the measured CO in flue gas was subtracted, then the remainder of the CO formed CO_2 (see Appendix A, Sample calculation A.7). The stoichiometric air was derived in this way. The coal gases, air heater and ESP leakages have the same values as above. This second criterion is called the "ID Gas (Chem. Anal.)".

The third criterion is actually called the "ID Gas (Balance Tech.)". This criterion utilised the back-end gas analysis (mobile analytical facility) and is based on the method that required what came out at the back-end, must be satisfied by what and how much was combusted at the front-end. It used the back-end flue gas analysis (also considered more representative than the coal side and quite accurate) with CO_2 as basis (because it is the largest measured component in the flue gas, rendering any multiplication error minimal). This, and the way of catering for incomplete combustion (as explained above) required two iterations (Appendix A, Sample calculation A.7). The CO_2^+ in the revised Ostwald diagram (Appendix A, Sample calculation A.6) could be compared against the measured CO_2.

The above mentioned analysis and manipulation of values can be seen in the Volumetric - Gravimetric back-end gas reconciliation, which is the next set of values. Graphically, these gas trends for all the tests can be seen in Figure 6.3. It should be noted that all three of these back-end (ID) gas mass flows are unequal in Rev. 0.

Coal quantity and quality and ash analysis:
The coal volume flow was calculated (Appendix A.5) from the feeder-integrator readings and served as a fixed input in Rev. 0, 1 and 2. The coal density in Rev. 0 was a hypothetical input of 1000 kg/m^3 for all coal qualities as a first iteration and the coal mass flow calculated from that. In Rev. 1 and 2 the iterations and macros solved for densities that would satisfy the three back-end gas mass balance criteria and then with the fixed coal volume flow produced coal mass flow.

Parallel ultimate and proximate coal analyses were performed by three laboratories (Lethabo, ESKOM TRI and New Vaal mine) giving results on an air dried basis. These were converted to an as received basis by means of the moisture analysis. The CV was determined with a bomb calorimeter for each sample as well. The representivity of the samples for the CV calculation presented a similar problem as found with the density. Experimentation proved that daily averages had to be biased 50 % to that of each test value, to get the best

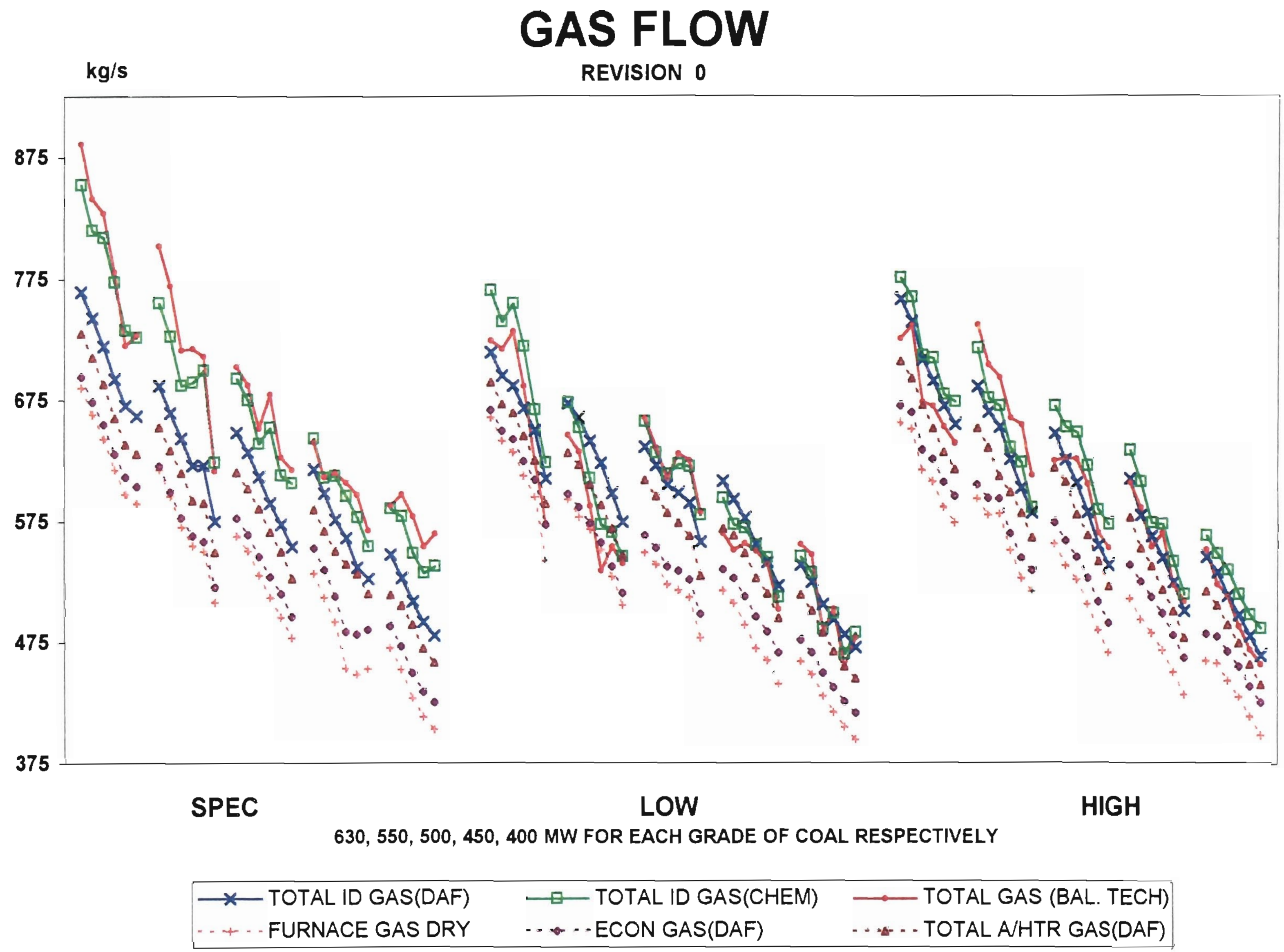


Figure 6.3: GAS FLOW (Rev. 0)

representivity when compared to the CV band of the specific coal ordered, which was known beforehand (Chapter 4.1.5 and Appendices C, D and E). These tests and the mentioned calculation methods also highlighted the fact that the CV determined with the bomb calorimeter was not representative of heat reeased by the combustion process in the burner. All the above, including the development of a calculated net CV at constant pressure (NCV_p), as opposed to the gross CV at constant volume (GCV_v) as per the bomb, is explained with motivations and references in Appendix A, Sample calculation A.8. (This NCV_p was based on a Dulong type formula, calculated from the elemental analysis.)

A parameter that is important for Lethabo coal is the heat percentage contained in the volatiles (HIV). All the volatiles in Lethabo coal are not combustible, but some are inert. It is therefore not always adequate to evaluate the percentage volatile content only, but also the HIV values. This value is calculated as such:

$$HIV = \frac{(CV_{as\ received} - (\text{fixed carbon } \% / 100 \times 33.82))}{CV_{as\ received}} \times 100$$

The value of 33.82 MJ/kg (calorific value of pure carbon) is the same value as that used by Gill[14] in the Dulong method calculated CV (Appendix A, Sample calculation A.8).

There were no ash analyses performed in the sense of initial deformation temperatures (IDT), ash fusion temperatures (AFT) etc., but unburnt carbon in dust and bottom ash was evaluated. These two values were averaged with weighting factors of 92,7 : 7,3 respectively as the ratio of dust (fly ash) to bottom ash. This is the ratio which was determined during the electrostatic precipitator guarantee efficiency tests. It is not known whether this ratio stayed constant with varying loads or air flows, but the trend should not be affected for the purpose of this project and this ratio was all that was available.

Milling plant:

The number of mills in service for each test was specified (also used in the mill seal air calculation) as well the mill configuration (see Chapter 5.1.1). The pf fineness distribution (% passing through the 75μm sieve) was noted, but a better image can be obtained by viewing the graphs in Appendix J. There were a few anomalies, but in general it can be stated that the process succeeded in keeping the pf fineness as constant as possible, thus eliminating it as a variable.

Working fluid conditions:

The reheater spray flows were separately noted since they were not included in the measured feed flow. The feed flow was measured by the special calibrated orifice (Chapter 4 and Appendix A, Sample calculation A.4), resulting in the total feed flow amounting to the sum of the orifice reading and the reheater spray flows. The total feed water flow to the boiler had to be accurately determined, since the STEP program is very sensitive to this value. These flows and accompanying temperatures were monitored to evaluate the influence of varying combustion air flow on the turbine side.

Condenser performance:

The condenser parameters were measured, since the condenser performance has a powerful effect on the STEP program and the accompanying accounted losses. It is also one of the first indicators to highlight a change regarding a change in target values. The tests were conducted in a very cold month of May with some of the tests at night time having even colder temperatures. Condenser performance is sensitive to these ambient temperature changes and any possible influence on the rest of the cycle had to be monitored.

Electrical parameters:

The electrical energy consists of the units generated (UG) and the auxiliary power that was consumed by the unit to operate its pumps, mills, fans etc. This was measured by calibrated current and voltage transformers (CT's and VT's) and converted into power by a computer that monitored continiously and provided a printout. Reconcilliation was necessary concerning the CW pump configuration, since they are supplied by different unit boards and the other two units on the Western side of the station, Unit 2 and 3, had been off for certain periods of the time during the Unit 1 testing. The CW pumps also do not consume identical power (due to different impeller diameters) and all this was thus noted during testing (see Chapter 5.1.7) and taken into account. The net energy on which overall efficiency calculations were based was the units sent out (USO) and that was obtained by subtracting the auxiliary power from the UG. These values were also entered into the STEP program where further calculations were performed, e.g. overall efficiency.

STEP output parameters:
The direct side overall efficiency is calculated on an energy in vs. energy out principle:

$$\eta = \frac{\text{USO}}{\text{Coal mass flow} \times \text{CV}}$$

Various overall efficiencies were calculated for each test. The same coal mass flow and units sent out were used throughout, but the different CV's were used as discussed previously, i.e. GCV_v as obtained by the bomb calorimeter, the daily averages thereof, the daily average biased 50% to the actual test value and NCV_p calculated from the elemental analysis.

From Figure 6.4 it can be seen that the efficiency calculated using the GCV_v as obtained by the bomb calorimeter gave peculiar erratic trends for a days' testing (unlikely to have been caused by the varying combustion air flow). Also, the orders of magnitude did not seem logical or probable (it is unlikely that Lethabo plant could have efficiencies exceeding 40%, and that with the low grade coal producing

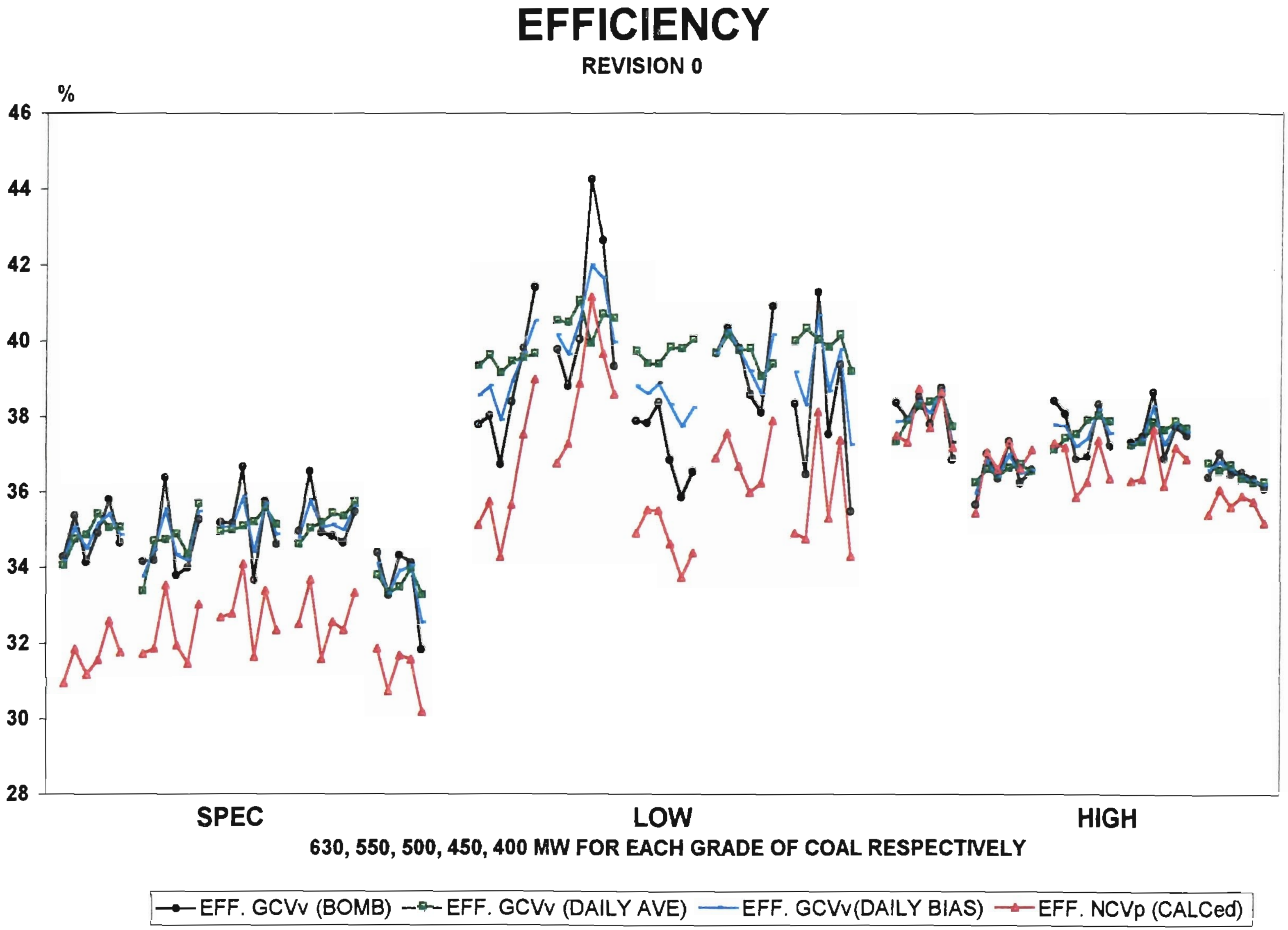


Figure 6.4: EFFICIENCY (Rev. 0)

efficiencies much higher than that of the spec. and high grade coal). It should be remembered that these efficiencies (Rev. 0) emanated with a hypothetical coal density of 1000 kg/m^3, but still, the variance could not have been due to that. The effect of this method (after Rev. 1 and 2) will be seen later, in the change of shape and order of magnitude of these efficiency graphs.

The overall STEP factor is the percentage of the target efficiency achieved by the actual efficiency:

$$\text{STEP Factor} = \frac{\text{Actual efficiency}}{\text{Target efficiency}}$$

The actual efficiency is as shown before. The target efficiency is the inverse of an optimum sent out heat rate multiplied by several correction factors (having the effect of sliding targets) involving the coal quality, load, etc. (See Appendix I for an explanation of STEP and the associated losses.)

The total accounted STEP loss is the sum of all the individual boiler, turbine and unit STEP losses calculated in a similar way as the above definition for the overall STEP factor. The unaccountable loss is the remainder when the STEP factor and total accounted losses are subtracted from 100%. A breakdown of the applicable accounted losses can be seen in the latter part of the spreadsheet.

6.1.2 Revision 1 data files

In Rev. 1, a hypothetical case had to be created first, in order to eliminate any possible erroneous data in the air flow, in-leakages and oxygen criteria. As explained before, this air flow side was the most reliable of the three criteria, and used as "anchor", toward which the values of the stoichiometric criteria were iterated (Rev. 1), and thereafter the back-end gas reconciliation iteration produced the realistic final results (Rev. 2).

First of all, the same principle in forecasting the maxima and minima of air flows (Figure 5.2 and the accompanying discussion in Chapter 5.1.6) was used to create a linear regression of the Total Air Flow (previously explained in section 6.1.1) and economiser oxygen in flue gas, for the values of one days' testing. The reason that these were the values that had to be linearly regressed is made clear in Appendix A, Sample calculation A.3.3. In summary, it can be seen in the equation below, where "z" equals the economiser oxygen in flue gas.

$$\text{Theoretical air} = \frac{\text{Total measured Air Flow} - \text{Air heater leakage}}{\left(1 + \dfrac{z}{23.15 - z}\right)}$$

These linear regressed values of economiser outlet oxygen against air flow produced a straight line. If this line was extrapolated to intersect the air flow axis (corresponding to oxygen = 0), that value would be the theoretical air flow. Since this value was obtained from the perfect straight line of linear regressed values, it was used as a target theoretical air flow for this Rev. 1 iteration. The validation for achieving this was by the utilisation of the "interpolation ability of large amounts of data in trends", as previously mentioned.

If in the above equation, this target theoretical air (for each day), the linear regressed oxygen values and the carefully measured total air flow (including the measurable leaks) were made inputs, an air heater leakage were solved for in each test. (It was found that this air heater leakage were a close approximation to a third degree polynomial, as a function of economiser gas flow). From these fixed economiser oxygen values (also used as "anchor" in Rev. 2) and this determined Rev. 1 air heater leakages, fixed air heater outlet oxygen values were determined. Similarly, with these air heater outlet oxygen values fixed and curve fitting from trends for ESP in-leakages, values for ID outlet oxygen were determined. These values were valuable as reference in the Rev. 2 iteration, where the reverse of this process took place (explained in Section 6.1.3).

Again, with the economiser oxygen values fixed as "anchor", the same process as above was performed in the other direction. This is how the furnace in-leakage and back-calculated furnace oxygen in flue gas were confirmed (see more detailed explanation in Appendix A, Sample calculation A.3.4).

All the above produced the theoretical air being a straight line (equal values) for each days' testing (Figure 6.5). To have satisfied this condition from the stoichiometric side i.e. the stoichiometric air equalling the theoretical air, some hypothetical assumptions had to be made initially to the criteria on the chemical side. (A basic need for the above also evolved around the erratic trend of the stoichiometric air in Rev. 0, due to the density.)

The hypothetical assumptions were based on the following:

- the coal analysis for a days' testing was exactly constant (percentage elements per kg of coal),
- and the machine load was exactly constant for that day, (USO, steam flow, feed flow)
- and the stoichiometric air flow also had to be constant for that day.

The order of magnitude was already determined by the theoretical air exercise above. Thus, in Rev. 1, the values used in the coal elemental analysis (C, H, S), as well as the USO, were made the daily average of those equivalent values in Rev. 0. This influenced the values of the stoichiometric air calculation per kg of coal, as well as the CV calc. method.

The stoichiometric air values achieved as such, were made equal to the theoretical air above by iterating the coal density until the two values were equal (Figure 6.5).

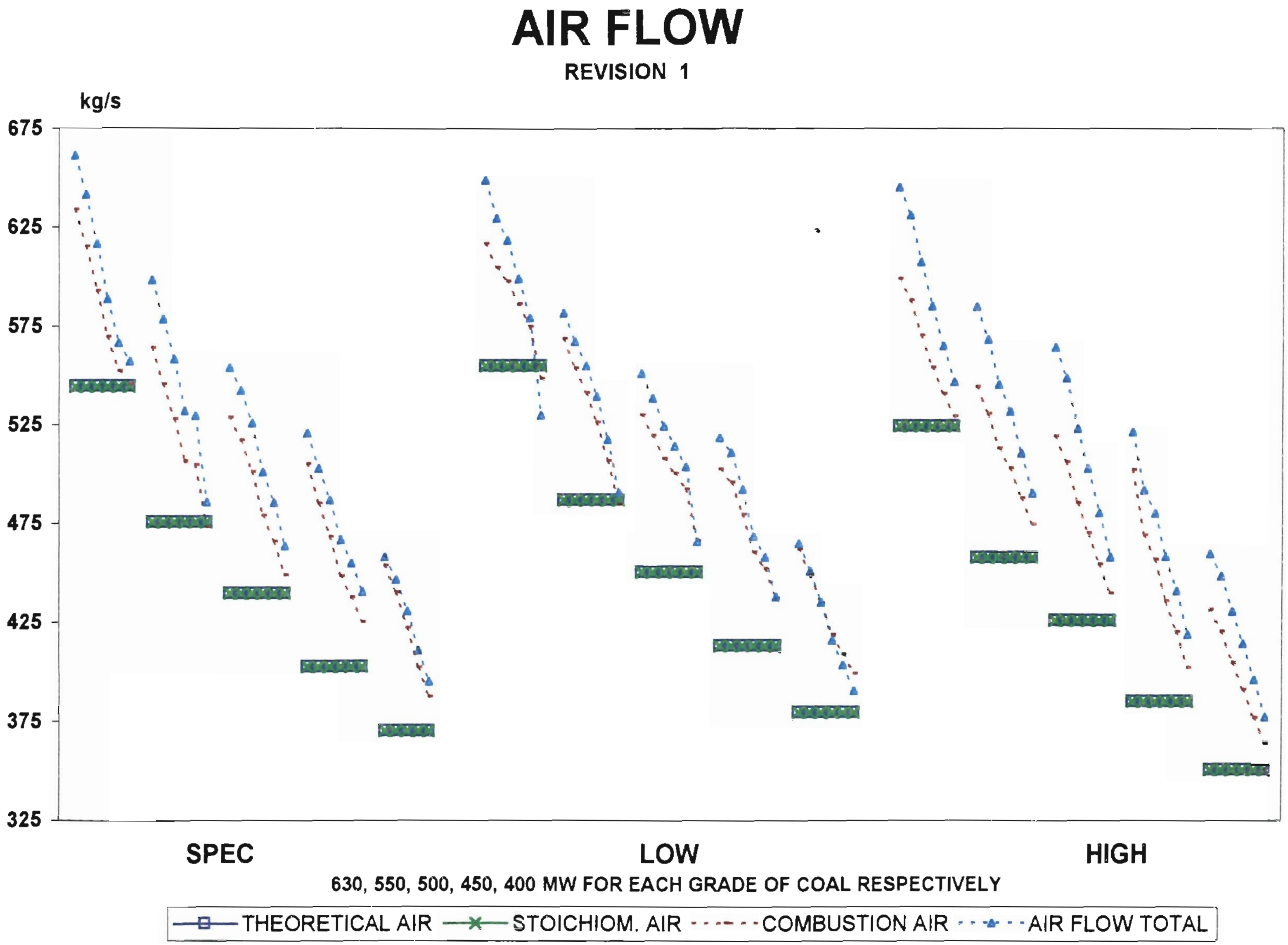


Figure 6.5: AIR FLOW (Rev. 1)

This whole exercise then produced the Total ID Gas (DAF) from the air flow, oxygen and leaks criteria to be equal to the Total ID Gas (Chem) for all the tests too (Figure 6.6). The Total ID Gas (Balance Technique) was still not equal to these two values on all the tests.

The new coal densities determined also produced new coal mass flows and together with the bomb CV's and the new calculated CV's, new efficiencies were also produced (Figure 6.7). There had to be merit in what had been achieved by this methodology thus far. The graphical trends of the calculated CV efficiencies (and some of the bomb CV efficiencies) were less erratic and showed smoother curves, with maxima or apices in some cases. The order of magnitude of all the efficiencies dropped to more acceptable levels and the high grade coal showed the highest values, with the spec. grade efficiencies lower but close to that of the low grade coal.

6.1.3 Revision 2 data files

The third and final step in this direct efficiency calculation method, was the utilisation of the third criterion, i.e. the back-end gas reconciliation. The point of departure was the inheritance of the Rev. 1 values of total air flow, the fixed economiser outlet oxygen, fixed furnace and ESP in-leakage (and resulting furnace oxygen), as explained in Section 6.1.2, into Rev. 2.

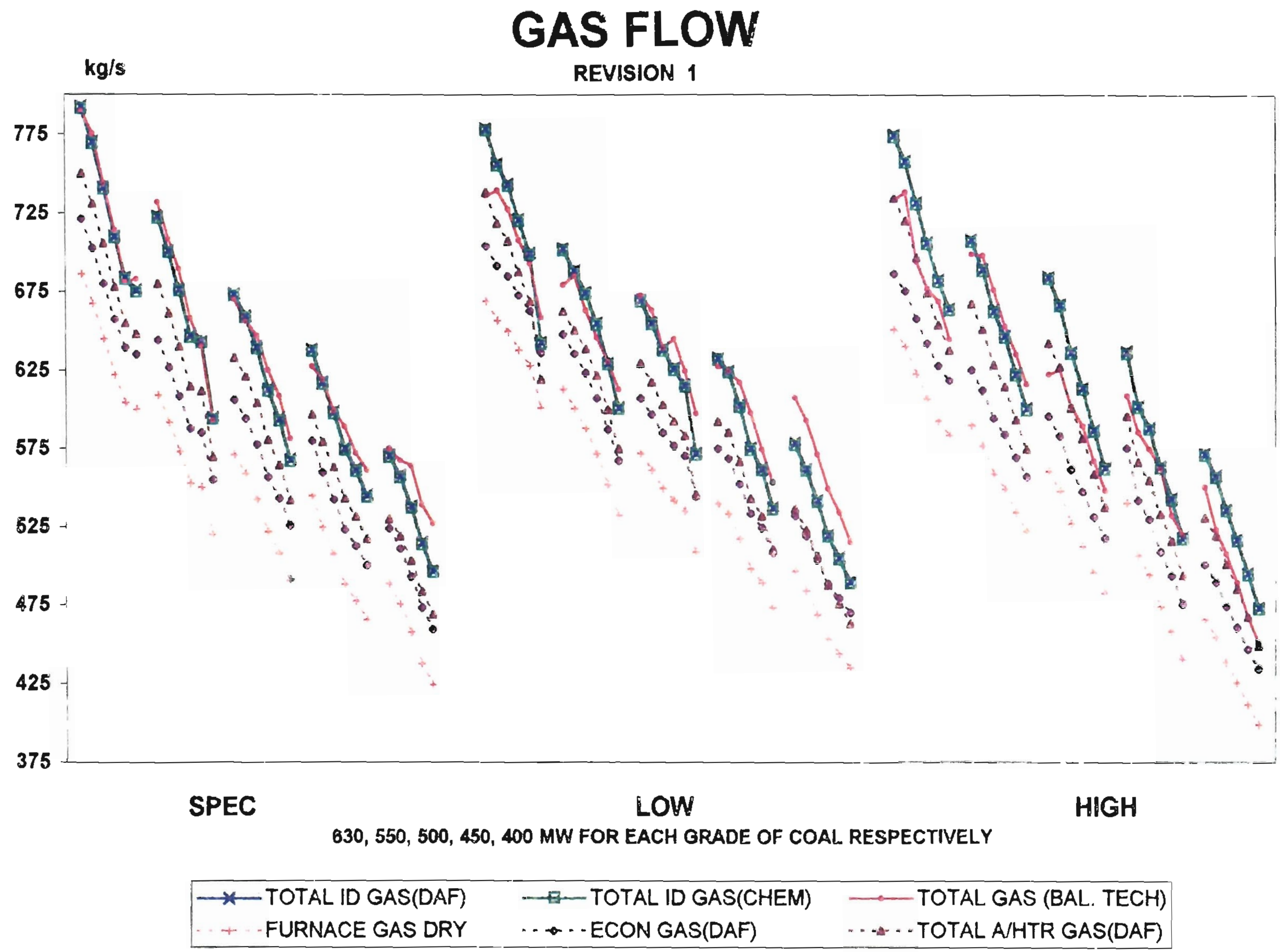


Figure 6.6: GAS FLOW (Rev. 1)

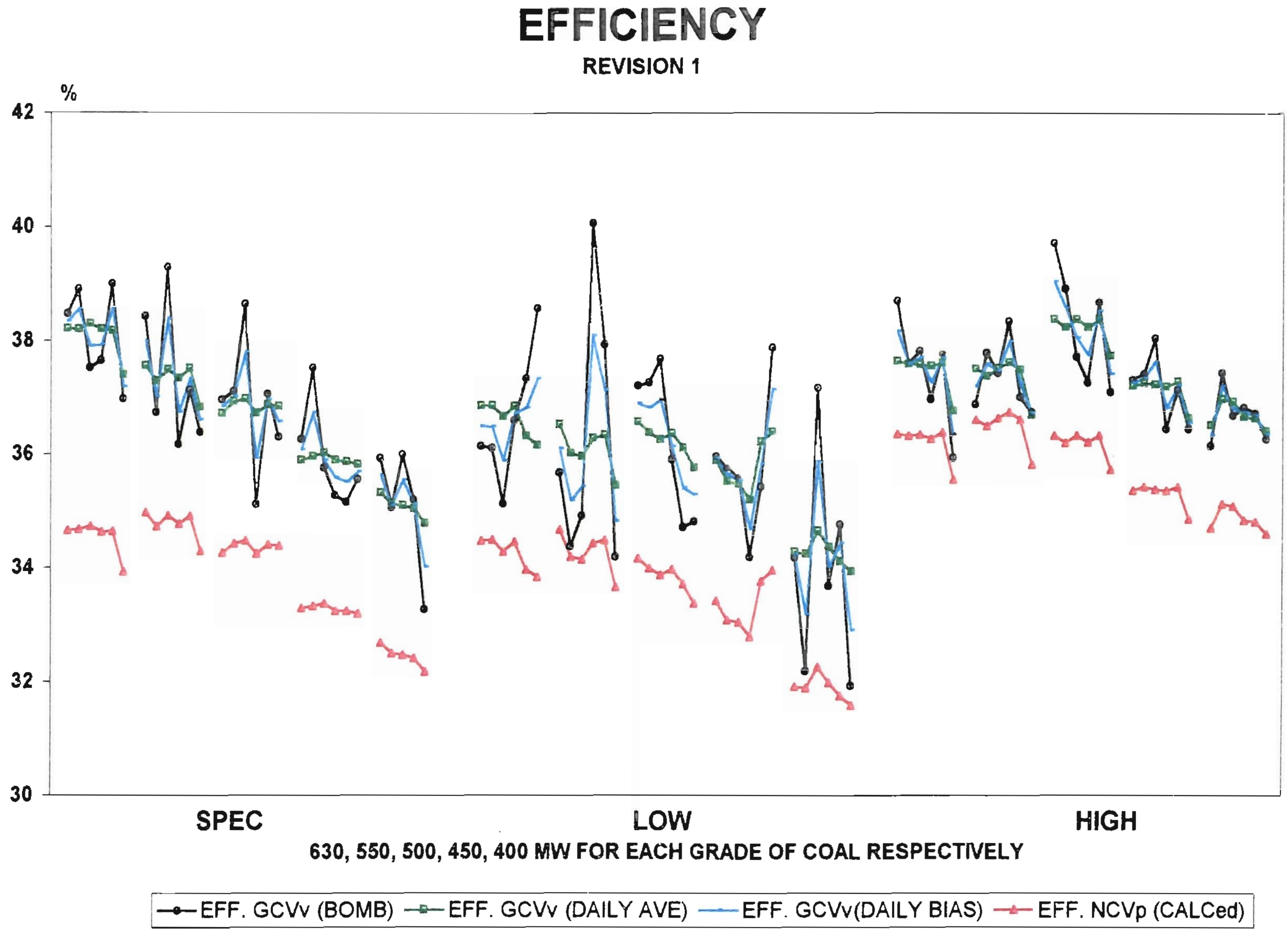


Figure 6.7: EFFICIENCY (Rev. 1)

It should be remembered that the CO_2 was used as basis to calculate the Total ID Gas (Balance Technique) in the back-end gas reconciliation method (Appendix A, Sample calculation A.7). The method thus determined the total gas mass flow from the CO_2 calculated by mass flow per kg of coal burnt (unburnt carbon and incomplete combustion taken into account) and that was the mass flow that was represented by the percentage measured in the gas analysis. The measured CO_2 also indicated what the O_2^+ ought to have been (via the revised Ostwald diagram, Sample calculation A.6) and vice versa.

The Rev. 1 daily average values for coal elemental analysis, USO, etc. were corrected back to the actual representative coal analysis (Figure 6.8) as in Rev. 0 (the daily average biased 50% to each test value), i.e. the hypothetical case reverted to the actual. The CO_2 values for each test were then iterated with a macro until the Total ID Gas (Balance Technique) also equalled the Total ID Gas (DAF). The density was then iterated until the stoichiometric air equalled the theoretical air as in Rev. 1 (which implied the Total ID Gas (Chem) equalled the Total ID Gas (DAF too)). See Figures 6.9 and 6.10. Each time the above operations were performed, all the previously mentioned iterations in Rev. 0 were automatically recalculated (air heater leakage, equivalent Ostwald gases, CO_2 back-end gas mass flow, and the CO incomplete combustion iterations) to have all mass-energy considerations satisfied. (For resulting leakages see Figure 6.11.)

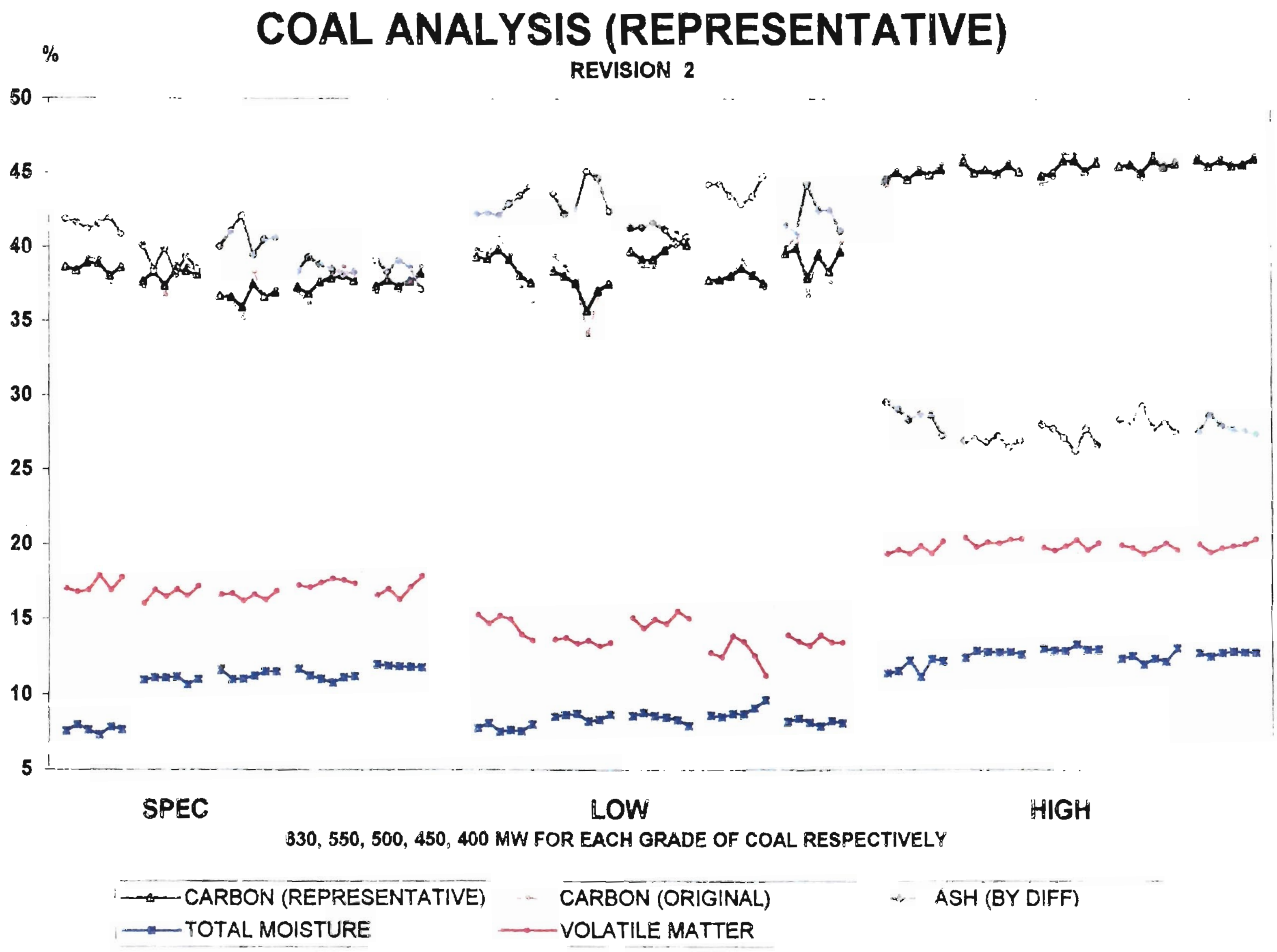


Figure 6.8: COAL ANALYSIS

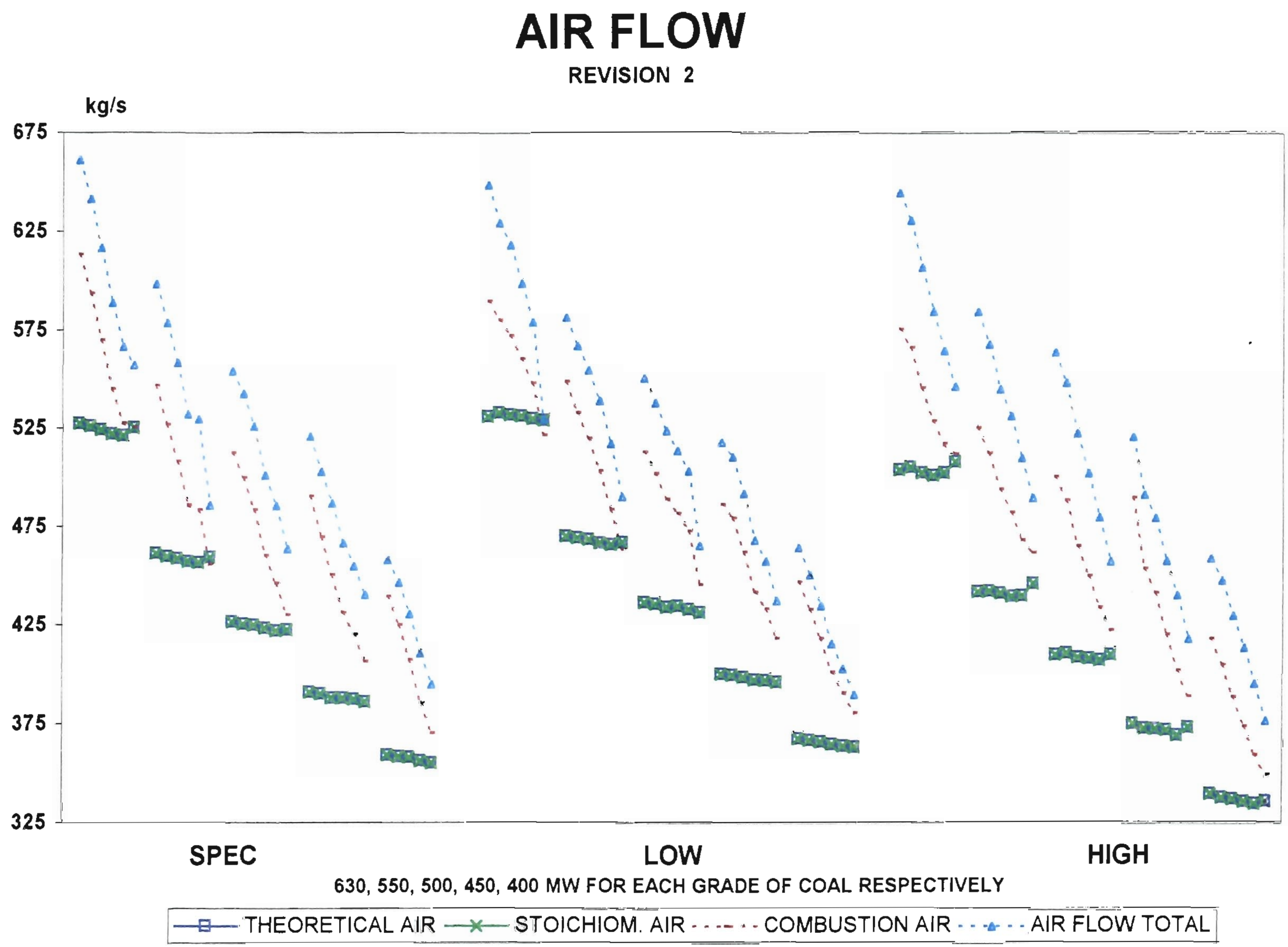


Figure 6.9: AIR FLOW (Rev. 2)

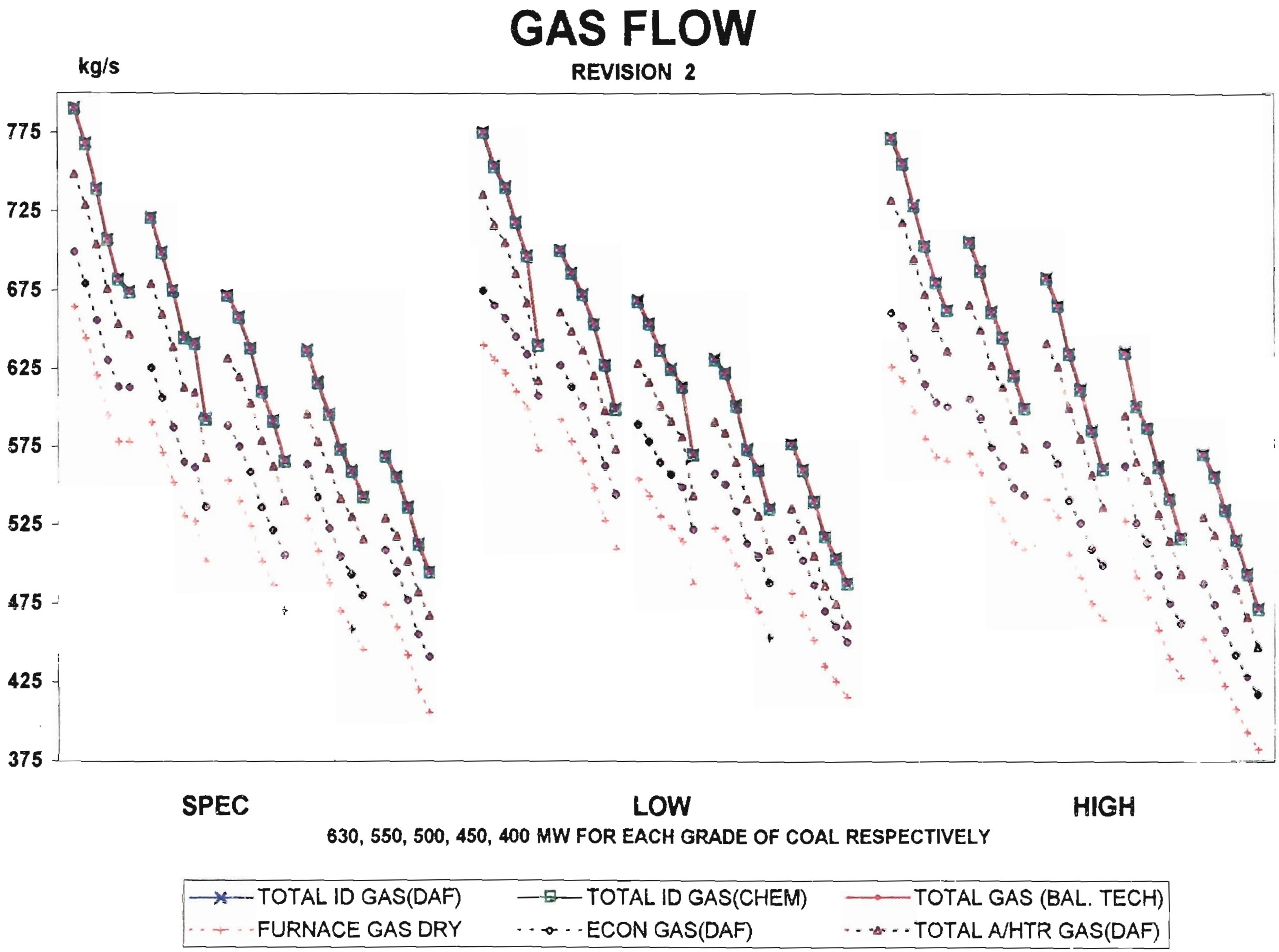


Figure 6.10: GAS FLOW (Rev. 2)

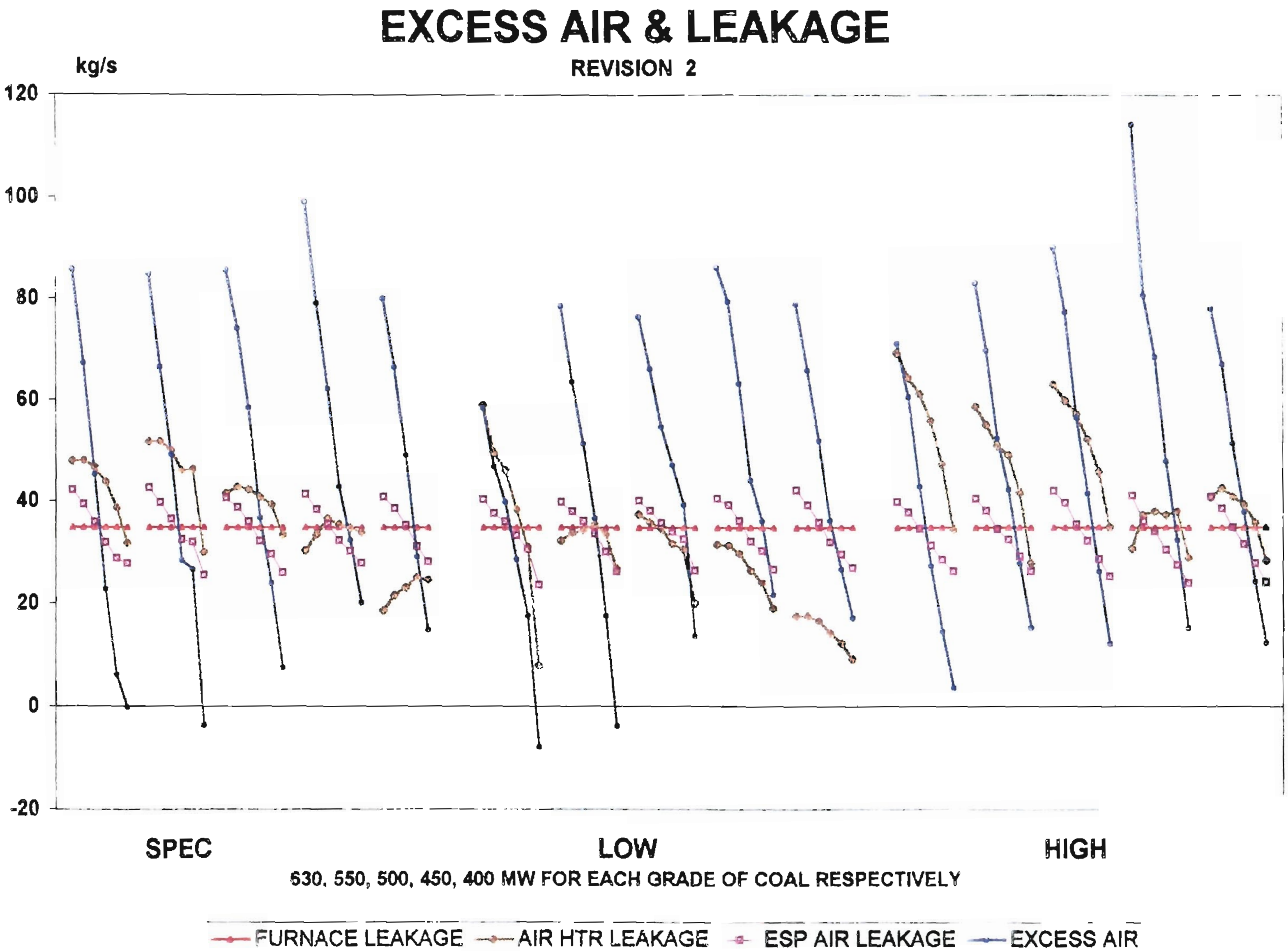


Figure 6.11: EXCESS AIR AND LEAKAGES

In Figure 6.11 the calculated excess air indicated negative values for the least air flow tests on certain days. This means the air flow could have been slightly sub-stoichiometric. (This can actually be confirmed in the CO graph which is discussed later and the oxygen graph (Figure 6.12), since those tests showed drastically rising CO and low to negative back-calculated O_2 values relative to the other tests of the same coal quality.)

Each time the above mentioned operations were performed, another calculation took place which was different to that in Rev. 1. The newly obtained CO_2 produced an equivalent O_2 according to the Ostwald diagram equations. The average of this value and the actual measured O_2 produced a new ID O_2. In a backward calculation with the equations in Sample calculation A.3.2 and A.3.3, by using this ID O_2 together with the fixed and previously determined ESP leakage, an air heater outlet O_2 was calculated. This newly obtained air heater outlet O_2 and the fixed economiser outlet O_2 (linearly regressed in Rev. 1), produced a new realistic air heater leakage, by means of the same equations. These air heater leakages produced new realistic theoretical air values from the equation below:

$$\text{Theoretical air} = \frac{\text{Total measured Air Flow} - \text{Air heater leakage}}{\left(1 + \dfrac{z}{23.15 - z}\right)}$$

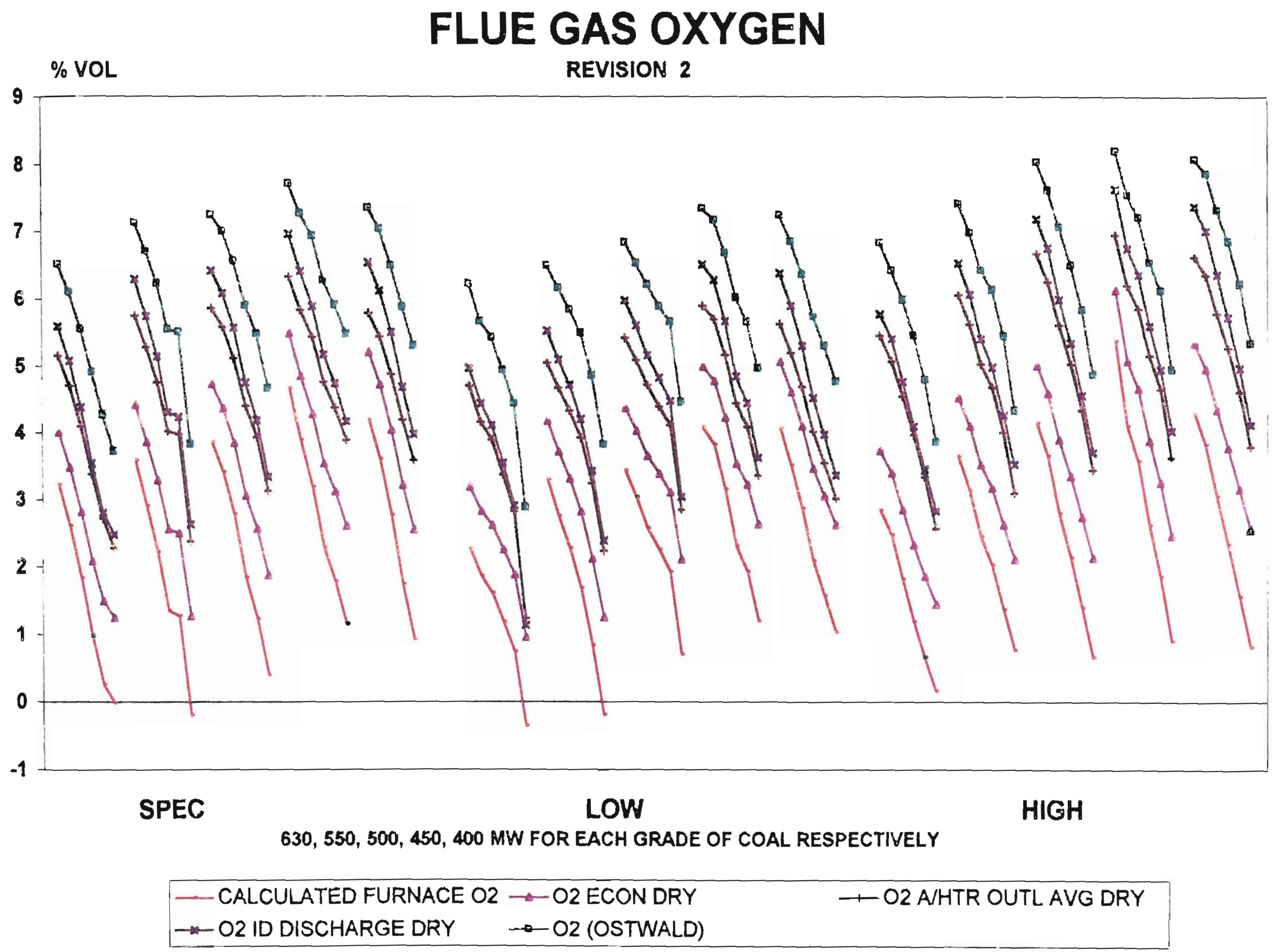


Figure 6.12: FLUE GAS OXYGEN CONTENT

The density was then again iterated, followed by the CO_2, and repeated until the stoichiometric air was equal to this theoretical air and all three the back-end gases were equal (Figures 6.9 and 6.10). These final densities produced coal mass flows and the required direct side efficiency curves (Figure 6.13).

This whole process had to be verified, although feasible results had been achieved with the efficiencies, etc. The iterated CO_2 which resulted after the three back-end gas mass flows had been made equal compared more favourably with the original measured value than the Ostwald value derived from the original measured O_2 value (Figure 6.14). For this exercise CO_2 was considered more important, reliable and accurate than O_2 for calculating gas mass flow, due to reasons mentioned (also the mass flow of CO_2 was greater than O_2, reducing multiplication errors, and it could only have originated from combustion, not in-leakages as was the case with O_2). The calculated coal densities which resulted have enabled this gas mass flow balance to show a remarkable trend correlation with the surface and especially the total moisture in coal (Figure 6.15). The Rev. 0, 1 and 2 densities are shown and the progressive improvement in the trend to correlate with the moistures is noticeable. Values of the densities for the different coal qualities and tests also correlated well with the typical characteristic of these coals and the moisture contents (e.g. the highest density for the low grade coal with its high shale and ash content).

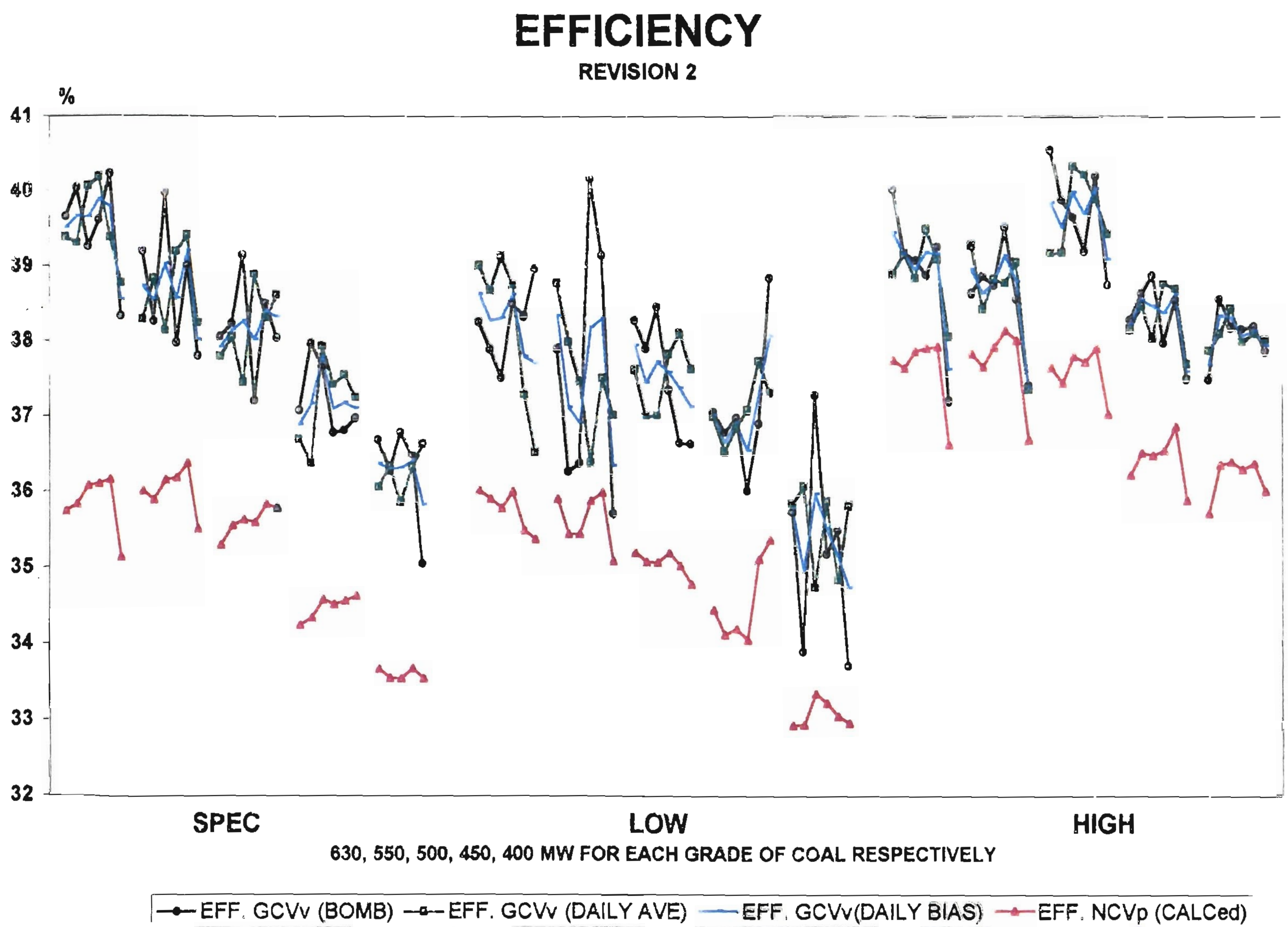


Figure 6.13: EFFICIENCY (Rev. 2)

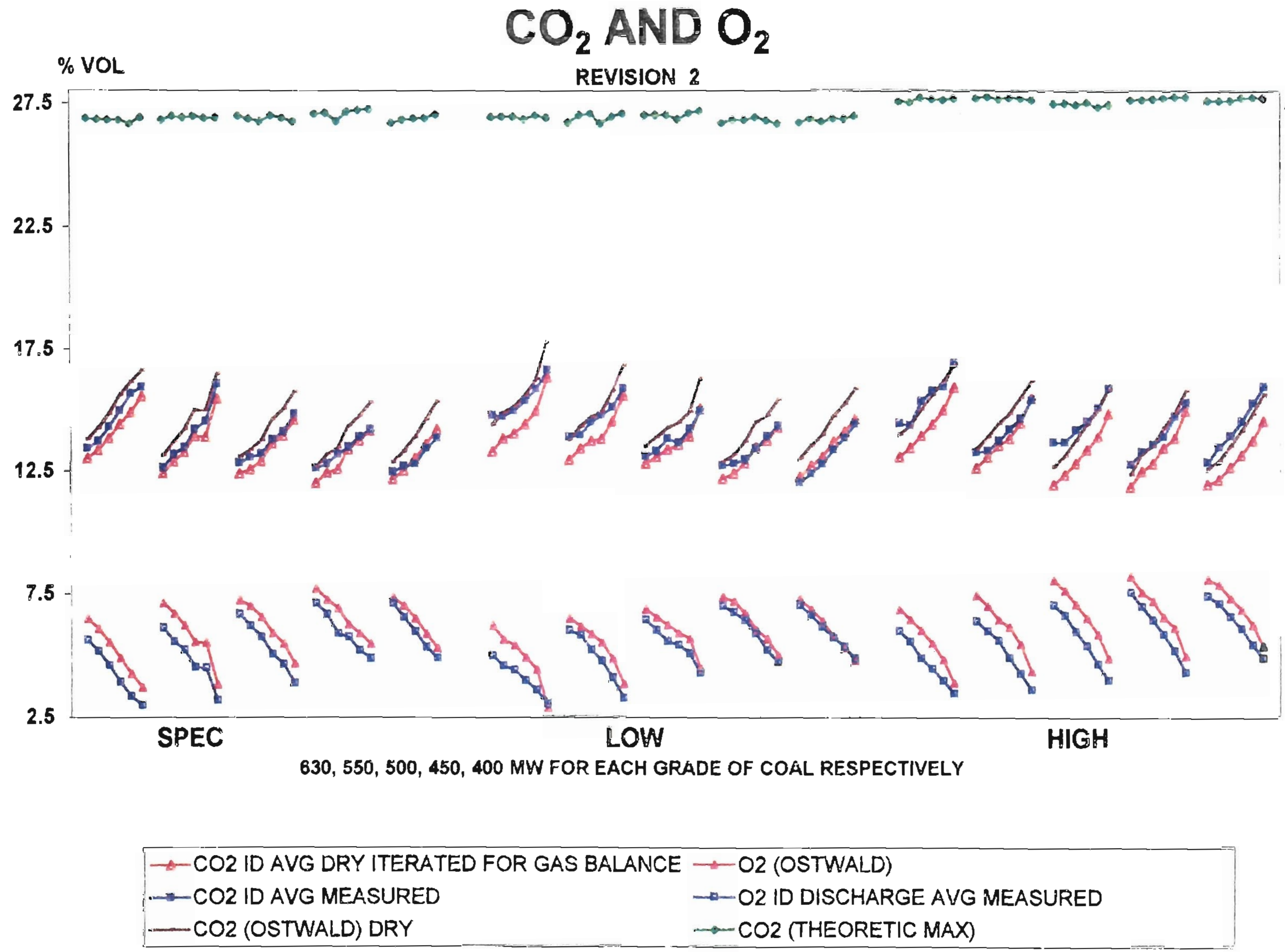


Figure 6.14: BACK-END CO_2 AND O_2 CONTENT

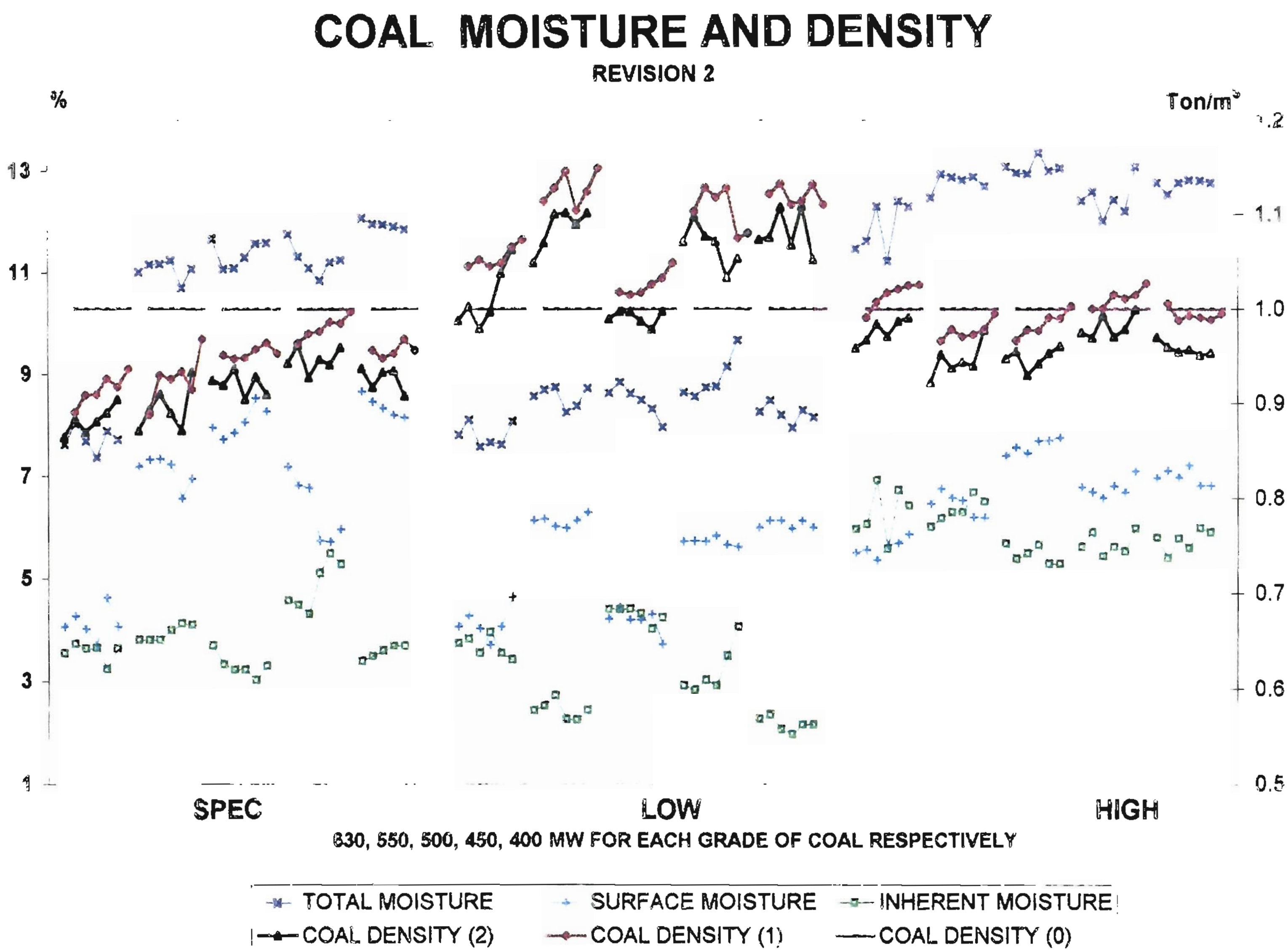


Figure 6.15: COAL MOISTURE AND DENSITY

6.2 MULTI-DIMENSIONAL VALIDATION AND CURVE-FITTING

In Section 6.1, this direct efficiency calculation method produced usable realistic overall efficiency graphs (Figure 6.13) plotted per test for the three coal qualities. The same overall efficiencies plotted against Total Air Flow, produced the X-Y graphs in Figures 6.16, 6.17 and 6.18. Although the maximum points seemed obvious and the large sets of data produced smooth curves with apparent probable apices only in some cases, there was also no certainty regarding the possibility of the maximum values being between the test points.

A mathematical curve fitting process was devised to produce a sixth degree polynomial curve-fit for each days' test points. This curve intersected most valid points of the actual test values. The first criteria applied to determine the air flow that produced the maximum efficiency on a load for a coal quality, was inspecting the possibility of that point being the mathematical maximum of the smooth curve-fit intersecting the points. The graphs in Figures 6.16, 6.17 and 6.18, were points connected by straight lines. This was not necessarily representative, therefore the curve-fit was necessary. These curve-fits are shown as ghost images on most of the graphs in the above mentioned figures.

It should also be pointed out that some of the tests were unfortunately not valid. E.g., the last two tests (lowest air flows) on the Low grade coal, 450 MW, were invalid tests, as explained in Chapter 5.2.4.

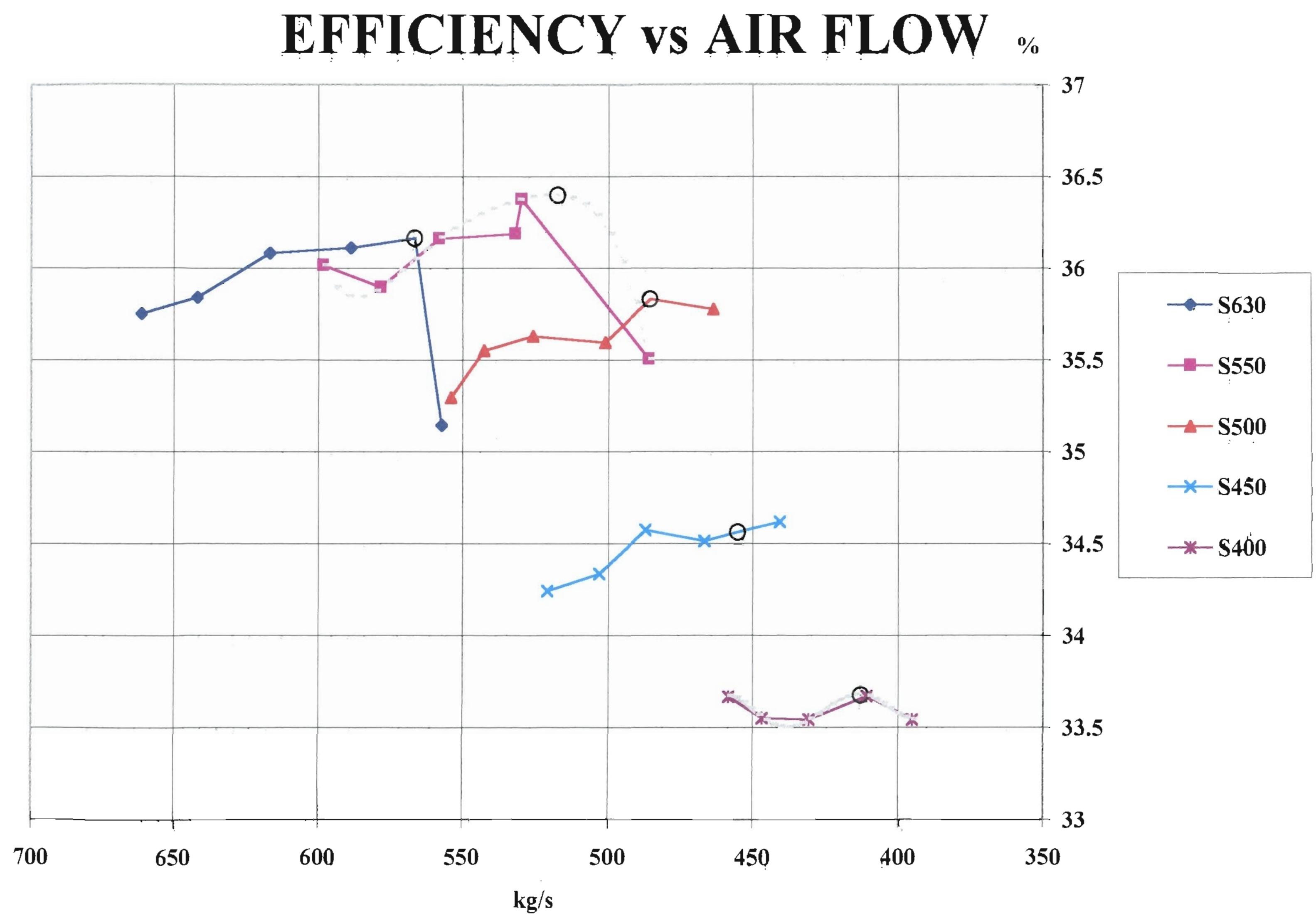


Figure 6.16: EFFICIENCY vs AIR FLOW: SPEC. COAL

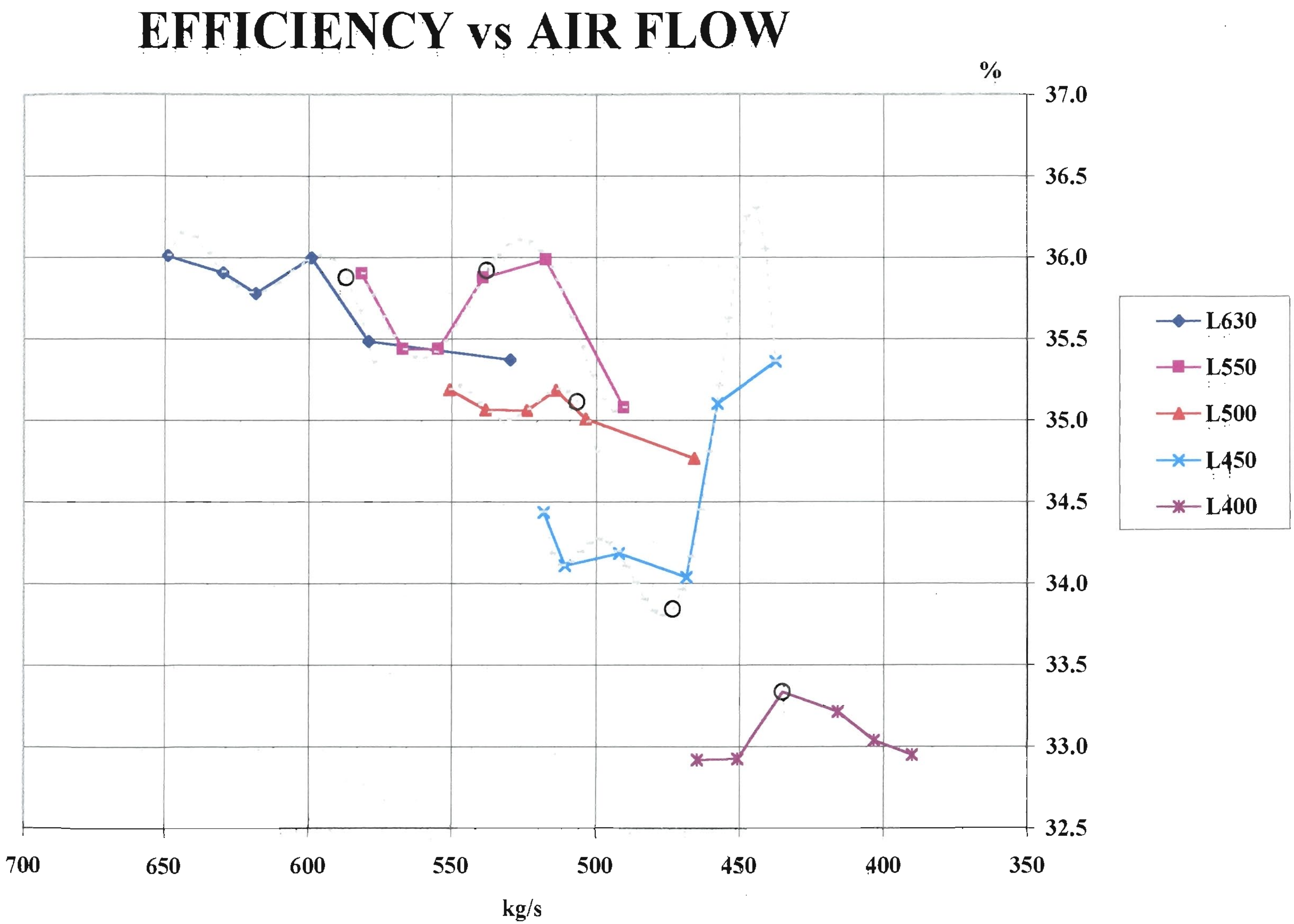


Figure 6.17: EFFICIENCY vs AIR FLOW: LOW GRADE COAL

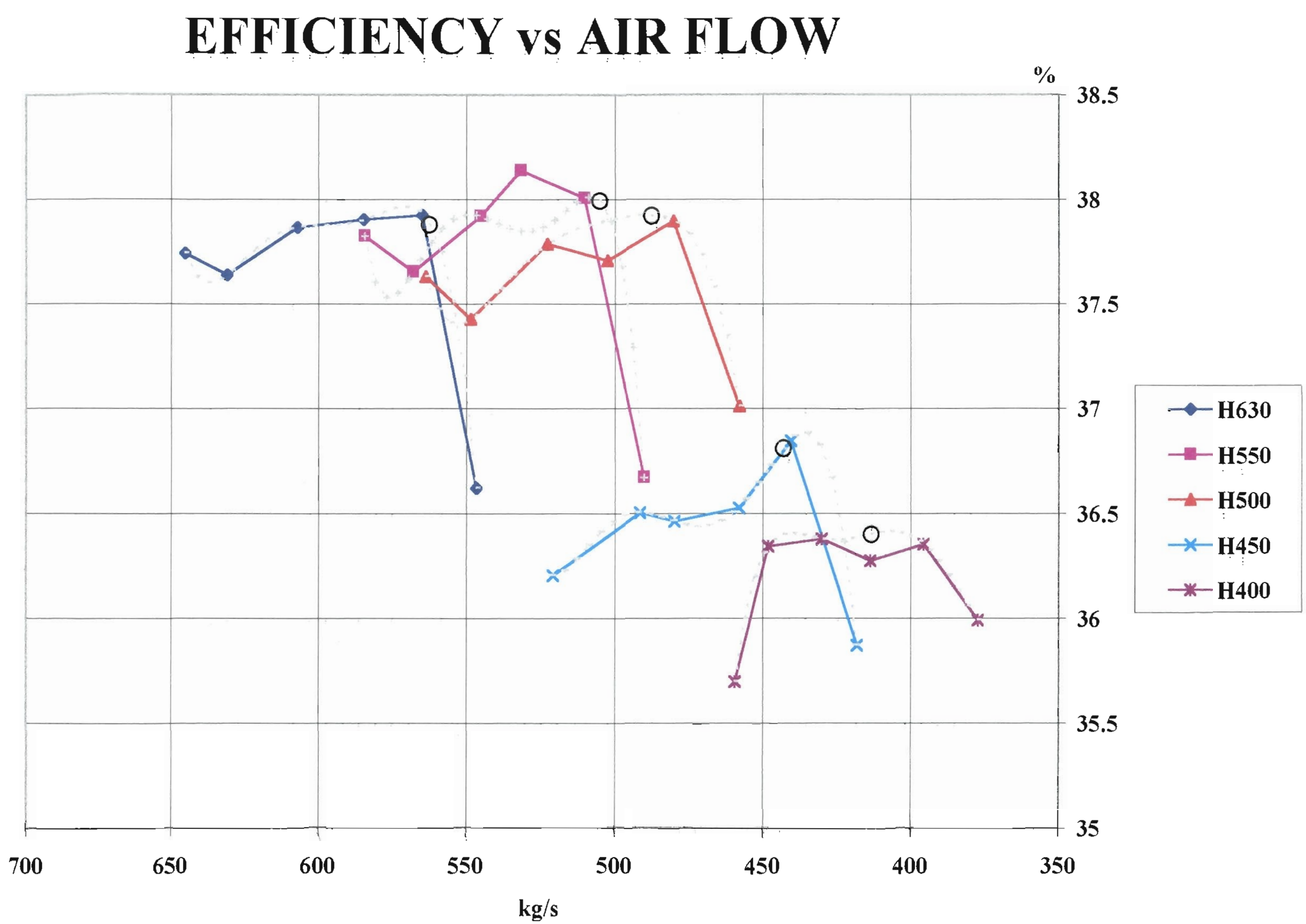


Figure 6.18: EFFICIENCY vs AIR FLOW: HIGH GRADE COAL

It will be seen that on some of these efficiency graphs, the first tests showed higher efficiencies than the later tests, which seemed against the logic of the trend. This was due to the time of day the test was conducted, as can be seen in the operational data in Chapter 5. e.g., in most cases the testing commenced in the early morning, when the first air flow (highest) test of the day was executed. Many times problems had to be sorted out after the first test (restripping a mill, recalibrating a suspect oxygen analyser etc.), enabling the execution of the second test much later that morning when the ambient temperature had risen. The lower temperature during the first test resulted in a more favourable condenser vacuum, contributing to the higher efficiency, since condenser vacuum has one of the most significant effects on efficiency. Some of the series of tests were conducted during night shift, these having the opposite effect as ambient temperature dropped. Operational outside effects such as these had thus also been taken into account during the evaluation process for the maximum point.

As mentioned, the power of the large sets of data was also used by permitting interpolation between loads (not only air flows) to assist the determination of a maximum, which benefit is not so obvious. This was extensively used in evaluating the optimum air flows (corresponding to maximum efficiencies) and economiser oxygen values, against units generated respectively. This is what is meant by cross-checking the results from another dimension, (Figures 6.19 and 6.20).

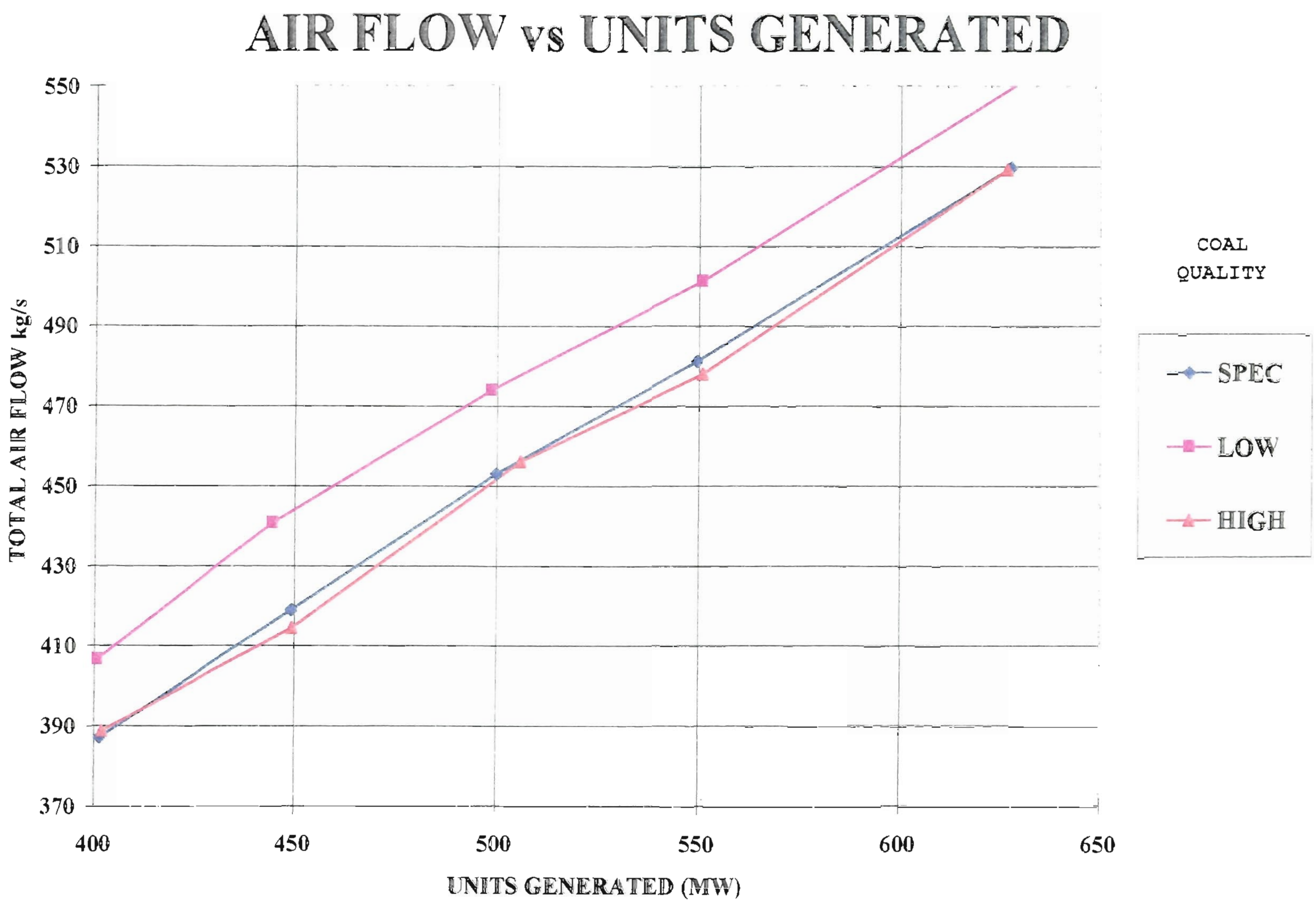


Figure 6.19: AIR FLOW vs UNITS GENERATED: CURVE FIT

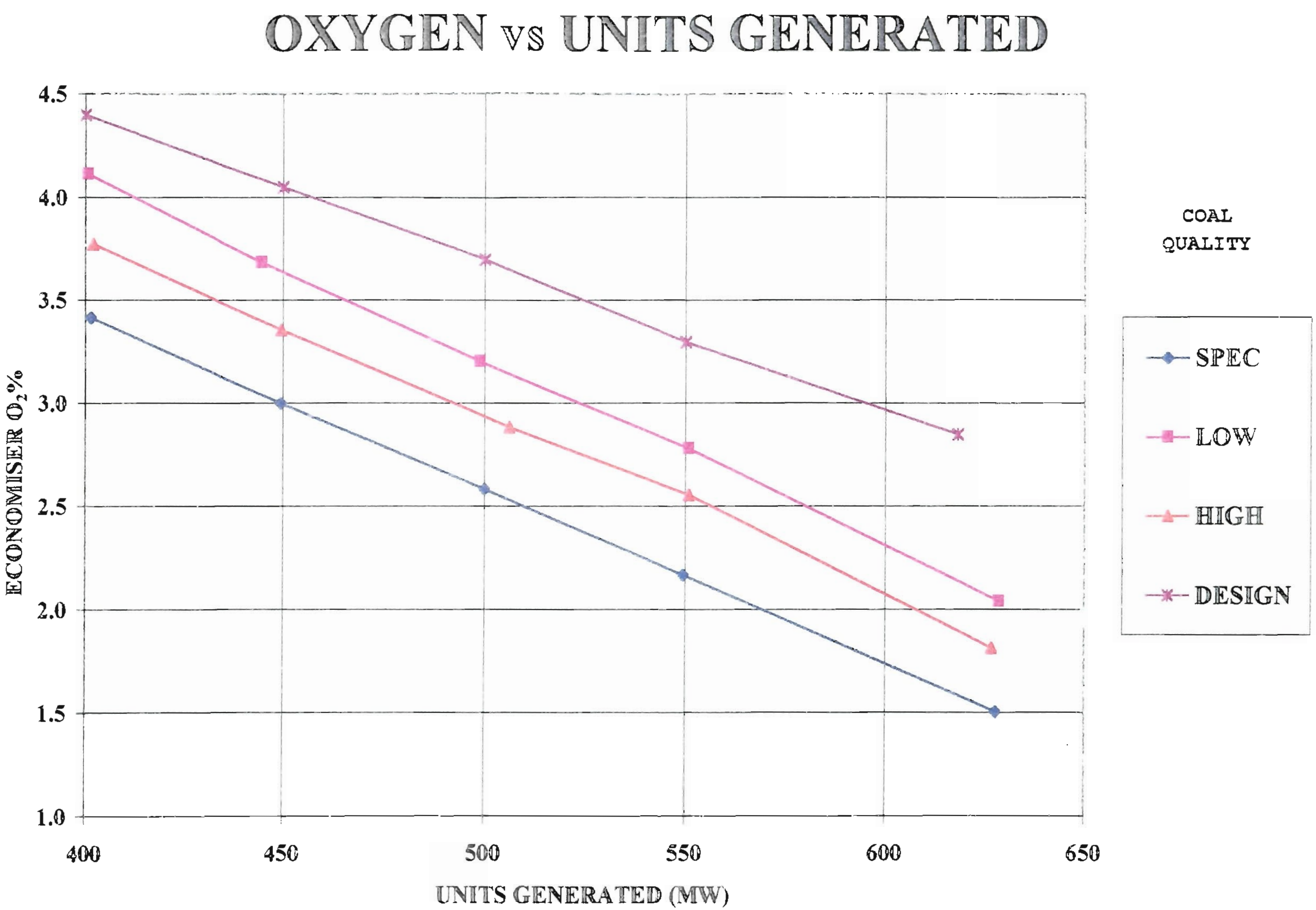


Figure 6.20: FLUE GAS OXYGEN vs UNITS GENERATED: CURVE FIT

The above mentioned graphs of air flow and oxygen against units generated had to be close to a straight line, or at least a very smooth or continuous curve. This was known from the design data and expected according to logic. If an apparent maximum point proved to produce an anomaly on these air flow or oxygen graph trends, it was usually where an efficiency graph had a very flat trend, giving a range of possibilities for the maximum in that vicinity. These air flow and oxygen against UG graphs thus greatly assisted in determining the maximum.

Figures 6.19 and 6.20 were the end result after all the above criteria were applied. Figure 6.20 also compared the new graphs obtained by these tests against the original design graph. The economiser outlet oxygen in flue gas differed from original design and these tests produced a different optimum for each coal quality. Originally no design air flow guideline was supplied.

All the maximum efficiencies of the spec. coal tests, which were obtained as such (encircled points on Figure 6.16), were compiled into one graph against units generated (Figure 6.21) to determine the load which would provide the absolute maximum efficiency. This amounted to 36.4 % at approximately 555 MW (90% MCR). This is different to the 100% MCR maximum provided by the turbine manufacturer, due to the fact that these tests evaluated the combined behaviour of the boiler and turbine as a unit and not as separate entities.

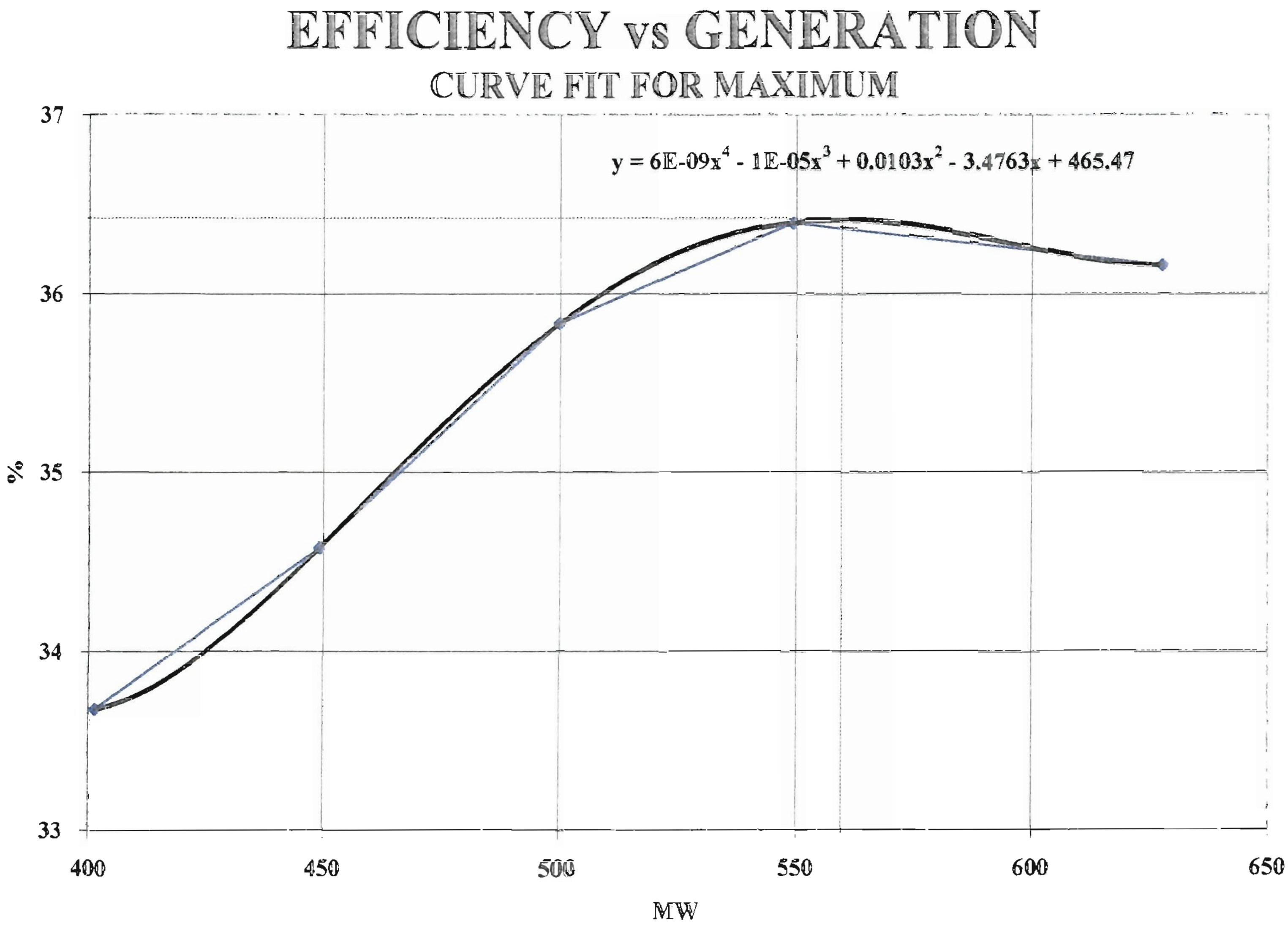


Figure 6.21: EFFICIENCY vs UNITS GENERATED: CURVE FIT

It became apparent that air flow could be a more important guideline than oxygen. Since, although the spec. and high grade coals had almost the same optimum air flows, the respective resulting oxygen guidelines differed significantly. This was attributed to the fact that the high grade coal had much more inherent oxygen than the spec. grade coal from the analysis (Appendices G and H). Thus, although the optimum air flows were very similar in quantity, the resulting oxygen values were significantly more in the case of the high grade coal, the high oxygen content in coal contributing to the flue gas oxygen quantity. Aspects such as this (coal quality and composition difference, furnace in-leakages, etc.) thus render the air flow a more absolute, safe and correct guideline opposed to flue gas oxygen, and this will be taken into account in the final recommendation.

6.3 ADDITIONAL OBSERVATIONS AND INTERPRETATIONS

There were some parameters measured that did not directly contribute to this efficiency calculation, but which needs interpretation. These explanations could in addition further validate the results achieved.

The Units Generated (Figure 6.22) illustrates that the load remained rather constant during a series of tests for a day. The few deviations which prevented this parameter being a straight line throughout, were the required changes made by National Control, as

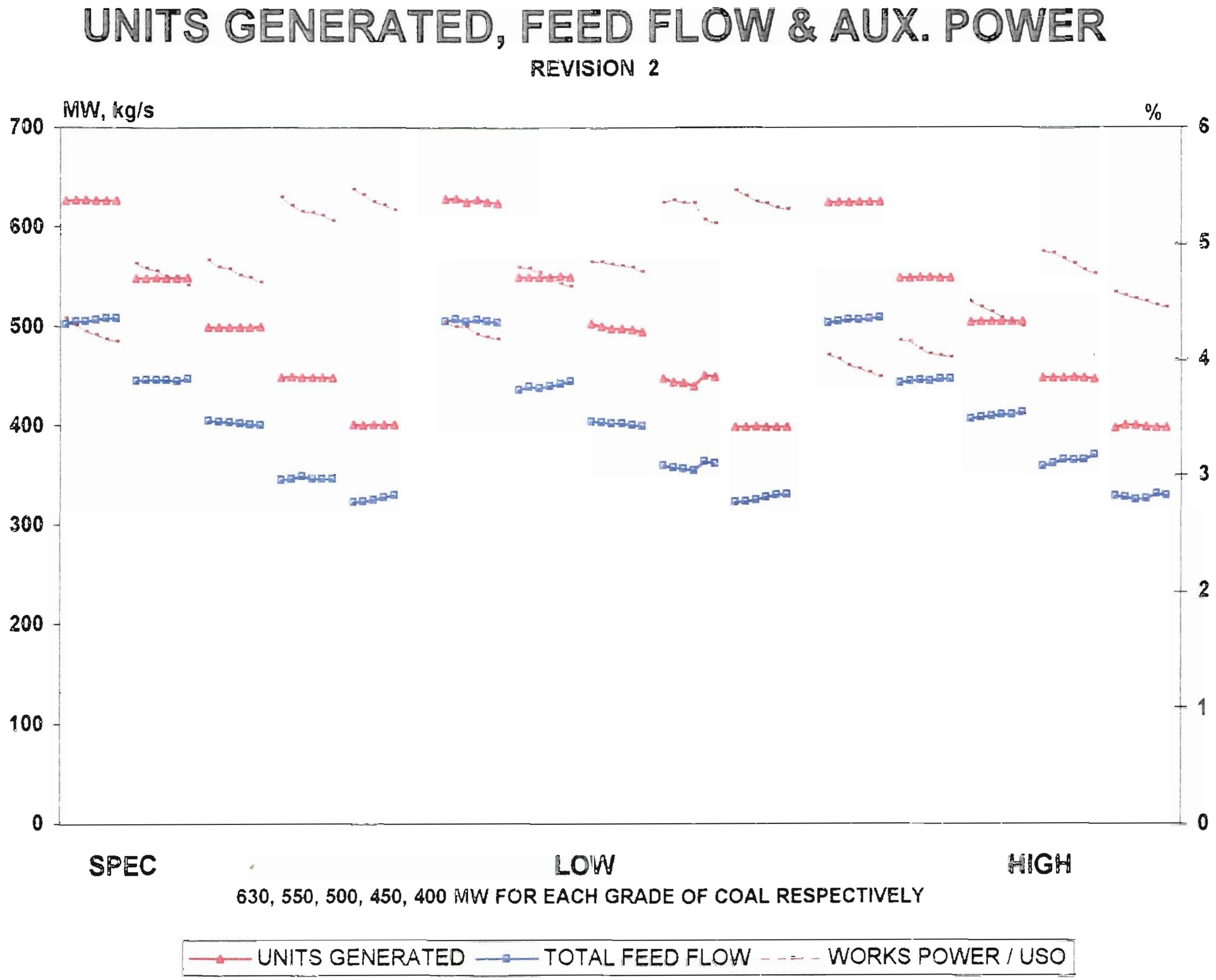


Figure 6.22: UNITS GENERATED, FEED FLOW AND AUXILIARY POWER

explained in Chapter 5. The only tests which were rendered invalid due to this parameter were the last two on the Low grade 450 MW tests, as mentioned previously.

The Auxiliary (Works) Power as a percentage of Units Sent Out (USO) (Figure 6.22) had a deminishing trend on each days' tests, caused by the fan power being directly proportional to the reduced air flow. This also served as one of the explanations why the optimum air flows obtained from these tests had higher values when compared to those achieved had the boiler been tested separately, or had the normally accepted criteria been followed (the least air flow theory). Also, the percentage is greater when fan power is a fraction of just the boiler auxiliaries, opposed to that of the whole unit. The fact that the average works power percentage increased with decreasing load is normal. It is caused by components such as mills and precipitators, which absorb constant power regardless of its load. There is also a certain fixed works power (e.g. lubricating oil pumps) that is constant regardless the load.

The Feed Water Flow (Figure 6.22) had a trend which was proportional to the theoretical/ stoichiometric air flow at a specific load (for constant units generated). This supported the theoretical/ stoichiometric air flow trends achieved, since because the working fluid flow rate proved proportional to the combustion rate, which had to be proportional to the theoretical/ stoichiometric air flows. In some cases, depending on the units generated, the feed water flow rate was inversely proportional to efficiency, which is correct.

The Main Steam Temperature (Figure 6.23, left hand temperature scale) remained very constant within a close temperature margin on the spec. and high grade coal tests. In some cases the first test (highest air flow) or the last test (least air flow) of the day showed a small increase in main steam temperature. This was due to the limit in the spray water control (steam attemperating) being reached, in compensating for combustion effects caused by either the high heat release barrier (see Chapter 4.1.1 for definition and explanations), due to the very high air flow, or possible slightly delayed combustion due to the combustion reaching a stage of being deprived of air respectively. The low grade coal tests showed the same trend as above, but with a greater variance in the main steam temperatures and with higher values. This was due to the lower percentage in volatile content of this coal, strengthening the above mentioned effect, relative to that of the spec. and high grade coals.

The Reheat Steam Temperatures (Figure 6.23, left hand temperature scale) remained more constant during testing at a load, with the occasional increased temperature on the first test due to the same reasons as above. The difference in average value between loads could have been influenced to different milling combinations (especially where top mills were in service or not). An important trend is that while the main steam temperatures varied in a closer range throughout

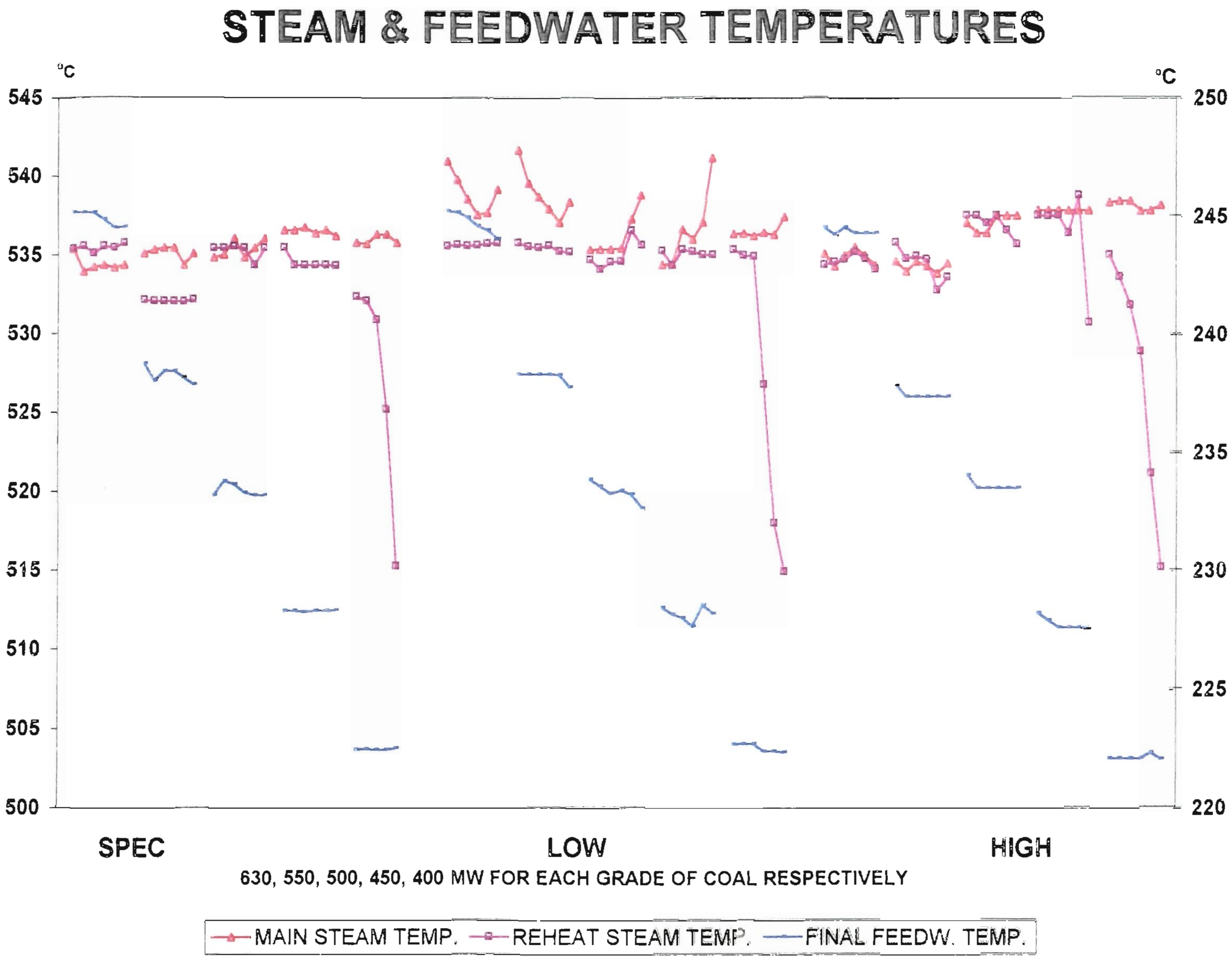


Figure 6.23: STEAM AND FEED WATER TEMPERATURES

all the tests, the reheat steam temperatures dropped significantly below target when the air flow was reduced at the low loads. An explanation for this is the fact that both the superheater and reheater tube banks are situated in the convection area of the furnace. The reheater banks are totally shielded from the radiant heat by the nose in the furnace, as well as the superheater banks. The superheater banks are also upstream of the flow relative to the reheater banks, being favoured by the convection heat transfer.

This phenomenon did not occur at one specific percentage excess air on a load with different coal qualities, possibly due to different milling combinations. The fact that this decay in reheat steam temperature was so significant (lower than 515 °C) motivates strongly against the least air flow theory. It also supports the logic that the optima should be at higher air flows. The same trend occurred on the Unit 2 tests[2], proving this not to be an isolated case. The high grade coal showed the worst case of this behaviour (on 400 MW as well as 450 MW). This allows predicition of similar findings on power stations with higher coal qualities too, not limited to Lethabo with a great portion of its coal being low volatile content coal.

In most cases, in parallel with the above phenomena, the final feed water temperature also reduced slightly (Figure 6.23, right hand temperature scale) or its flow rate increased (Figure 6.22). This is attributed to the reheat steam at reduced temperature passing through the IP and then LP turbine cylinders only. (There is no bled steam taken from the HP turbine cylinder and only main steam passes through it.) It is from the IP and LP turbine cylinders that the bled steam for the HP and LP feedheaters is taken. It is logical that the total enthalpy of the feed water would reduce if the bled steam total enthalpy for those heaters was decreased, or the flow rate had to increase to maintain the same total enthalpy. This implies reduced efficiencies, since the whole unit with its turbine side effects such as the above were also taken into account, not the boiler only.

The Unburnt Carbon in Ash (Figure 6.24) consisted of the carbon in dust and the carbon in rough (bottom) ash, which had a ratio of 92.7 : 7.3 percent respectively, as explained in Section 6.1.1 under "Coal quantity and quality and ash analysis". Due to the "grab-sampling" method applied at the submerged scraper conveyor (SSC) after each test, it can be seen that the representivety of the bottom ash was not good. This was not serious since it constituted only a small portion of the total ash. The greater portion, the fly ash or dust is actually the component of the ash that represents what happened in the combustion process. The mean carbon in ash was weighted according to the ratio above. Except for minor anomalies, the trend showed a typical behaviour throughout where the lower the combustion air flow, the higher the unburnt carbon in dust.

There was a noticable increase in the carbon in dust value with the first test or two at each load, indicating that the air flow was

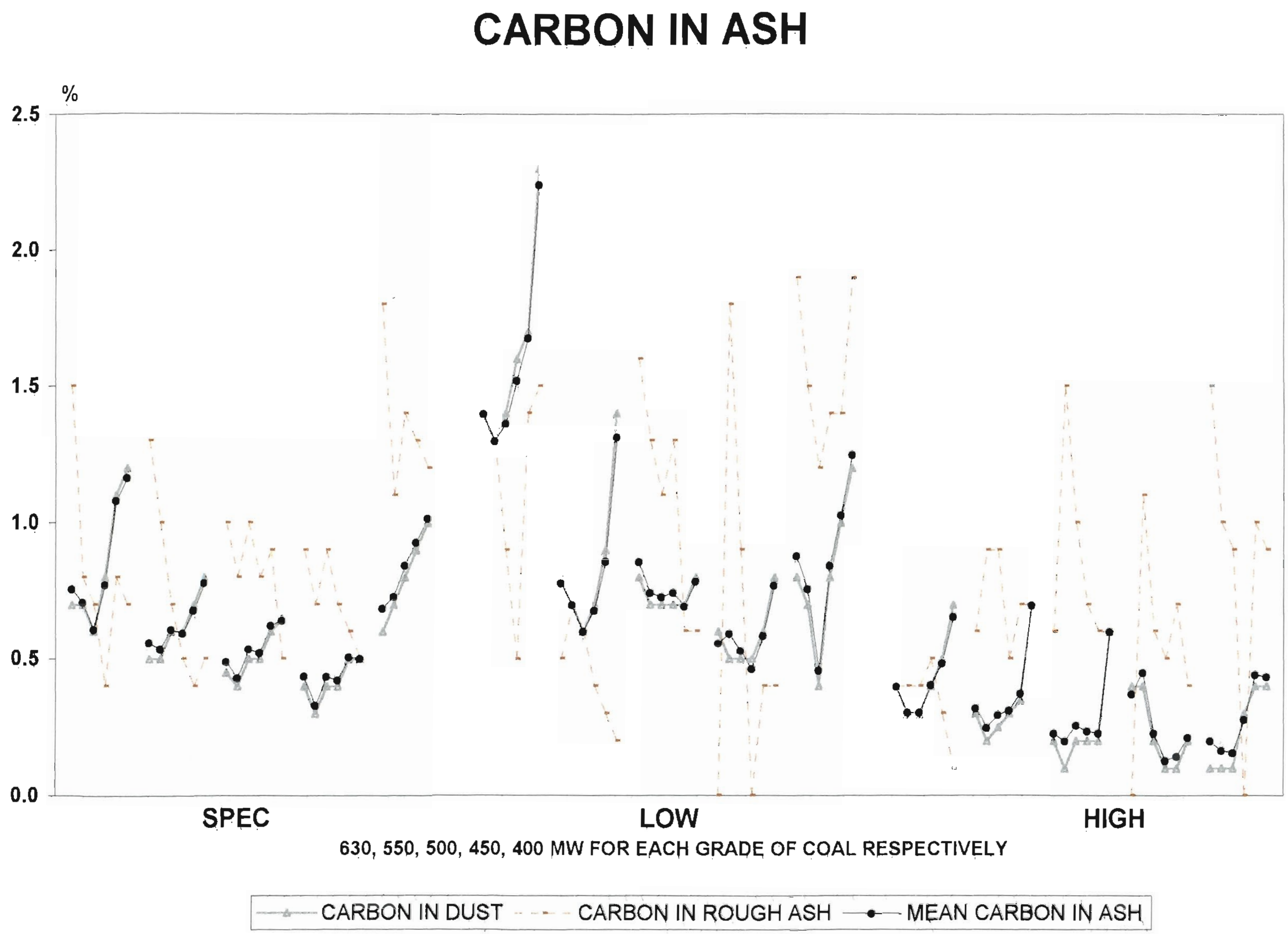


Figure 6.24: UNBURNT CARBON IN ASH

excessive relative to the burner dimensions and the swirl generator setting, causing some degree of incomplete combustion. This corresponds with leading international findings on burner swirl in pf combustion research[29]. The trends (Figure 6.24) also showed that the high grade coal had on average the lowest carbon in dust per load, followed by the spec. grade, with the low grade having had the highest carbon in ash due to its low volatile content. Each coal quality also had the highest carbon in dust at the highest load, thus proportional to load which was normal.

These trends of carbon in ash also indicated the improbability of maximum efficiency occurring at the least air flow. This is supported by the research concerning the Deflagration of Coal[30]. This research highlighted the actual reason why Lethabo low grade coal ignited at all, since in theory it is not suitable for this application of pf combustion. Briefly, the findings indicated that a certain minimum amount of oxygen had to be available for adequate ignition, and that the combustion efficiency improved with increased oxygen. In the presence of adequate combustion air the oxygen was stated to infuse the pf particle prior to ignition, causing the particle to swell enough to be fragmented, thus increasing the surface area available for heat transfer exponentially. This compensates for the low active volatile content of the coal, which is the major ingredient in sustained exothermic pf combustion. The findings of this microscopic scale study argued against a least air supply theory, but rather that the maximum efficiency would occur with some higher value combustion air flow, which were the findings of this macroscopic full scale tests.

The formation of CO due to the reduced air flow (Figure 6.25), corresponded in trend with the carbon in dust. The fact that CO only started forming significantly at the least air flows at a load, indicated a well balanced boiler with burners and mills in good operational condition (see Chapter 5.1.7, 5.2, 5.3 and 5.4). The high grade coal produced the highest CO values for approximately the same percentages of excess air, followed by the spec. grade and the low grade having the least. This leads to the conclusion that low grade coal should rather not be subjected to very low air flows as an operating practice, since a CO monitor will give very little prior warning to major efficiency changes.

The formation of SO_2 was proven dependent on the sulphur content of the coal. It is noted therefore that the High grade coal had less SO_2 formed (Figure 6.25) on average per load than the Low and Spec. grades (see coal qualities, Appendices F, G, and H). The increased trend of ppm SO_2 in flue gas at a load was due solely to the reduction in excess air, causing lower flue gas mass flow, the absolute quantity of SO_2 remained the same however.

The NO_x showed an almost opposite trend to that of the SO_2, due to the increase of thermal NO_x formation with increasing air flow, on all

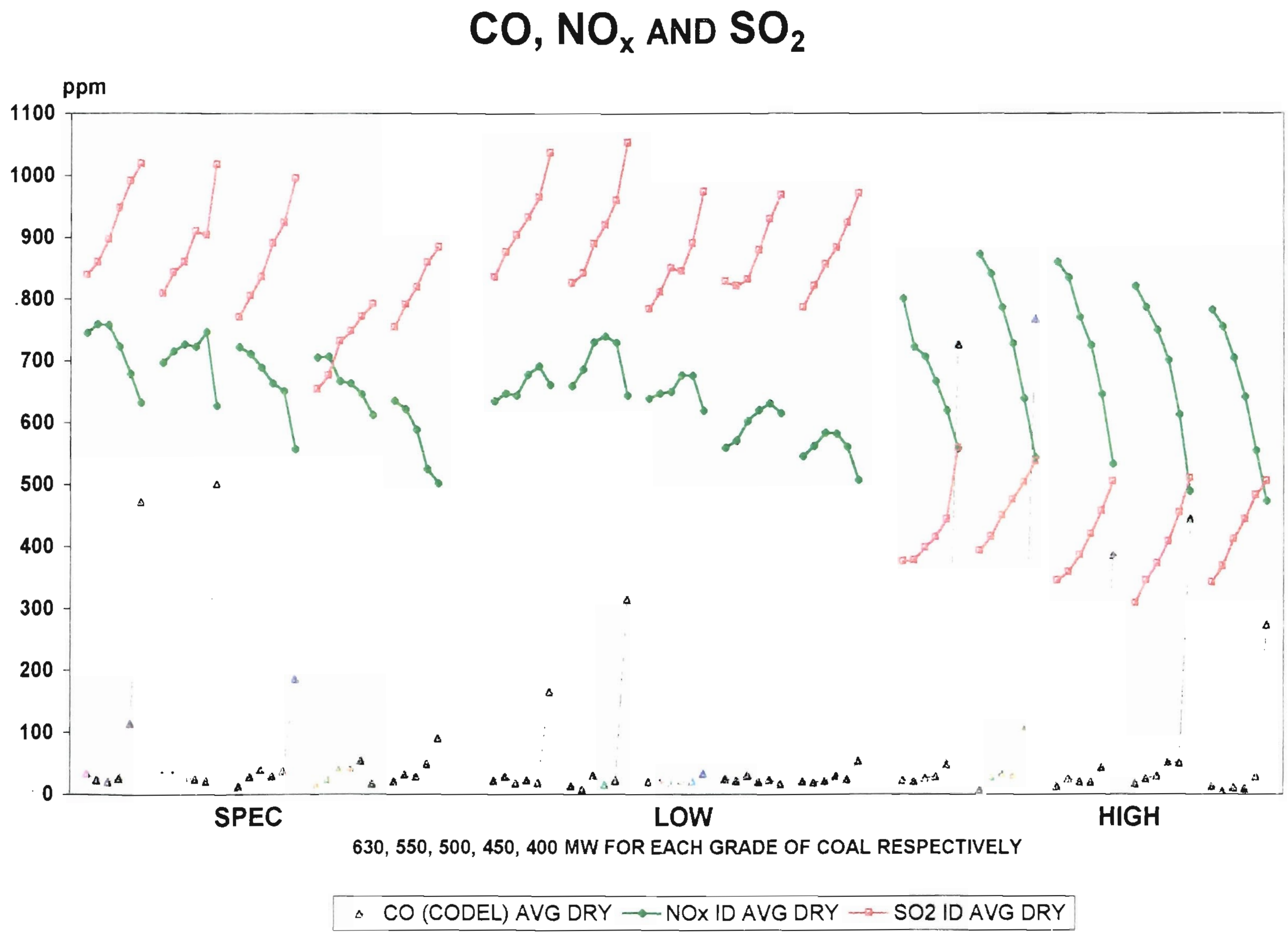


Figure 6.25: CO, NOx AND SO_2

the high grade tests and most of the spec. grade tests. Fortunately, on these tests the maximum efficiency points coincided with the second to third best NO_x emission rates on the trend of a load. The two highest loads on the spec. grade and all the low grade tests showed an apex in the trend, with the maximum amount of NO_x emission rates unfortunately in the vicinity of the maximum efficiency points.

It is suggested that this should not be offered as an argument to favour the least air flow criteria, due to the fact that the difference in the lowest and highest NO_x emission rates on these loads were less than 100 ppm NO_x. Also, it should be remembered, that in the temperature range of this combustion process (± 900 - 1300 °C), approximately two thirds of the NO_x in flue gas comes from the nitrogen in coal, not thermal NO_x formation[32]. Air flow adjustment does not have all the influence on NO_x formation. A final argument supporting the highest efficiency air flow as optimum, is the fact that the absolute amount of CO_2 released into atmosphere is much more, a quantity five orders higher than NO_x and SO_2. The highest efficiency would result in burning the least coal, (and which introduce less nitrogen in coal) which would produce less CO_2.

The optimum air flow and oxygen in flue gas, which were determined from these maximum efficiency criterion tests, required lower air flow values than the design values (Figure 6.20). Lower CO_2 and NO_x emission rates would result from these guidelines than the original design. These NO_x values compared favourably with average European emissions[31]. The reference shows graphs of standard burners producing NO_x emission rates of 550 - 850 ppm in Europe, with special low NO_x burners producing NO_x levels of 250 - 500 ppm.

The profile of the Ambient and FD Inlet Temperatures were proportionally related (Figure 6.26) and showed an indication of the time of day the tests were conducted (confirming the argument offered in the explanation of the effect of condenser vacuum advantage on the tests conducted in the early morning (Figure 6.16, 6.17 and 6.18, Section 6.2). The FD inlet was higher than ambient by that amount of heat recovered from the boiler house radiant loss, since the FD intakes are situated at 73m level inside the boiler house. The No-leakage Air Heater outlet temperatures are higher than the measured Air Heater outlet gas temperatures by the amount of heat saved had no air heater leakage taken place (as explained in Section 6.1.1).

The important trend to note here is the fact that these mentioned temperatures showed an increasing trend with reducing air flow, while the Dry flue Gas (Dfg) Loss had a decreasing trend with the same. This proves that mass flow had a greater influence on Dfg loss than temperature (an argument also offered in Section 6.1.1, under Air and flue gas properties). Although Dfg loss is favoured by the least air flow theory, it is not the only loss and this overall efficiency approach produces the maximum at the sum total of all boiler and turbine gains and losses.

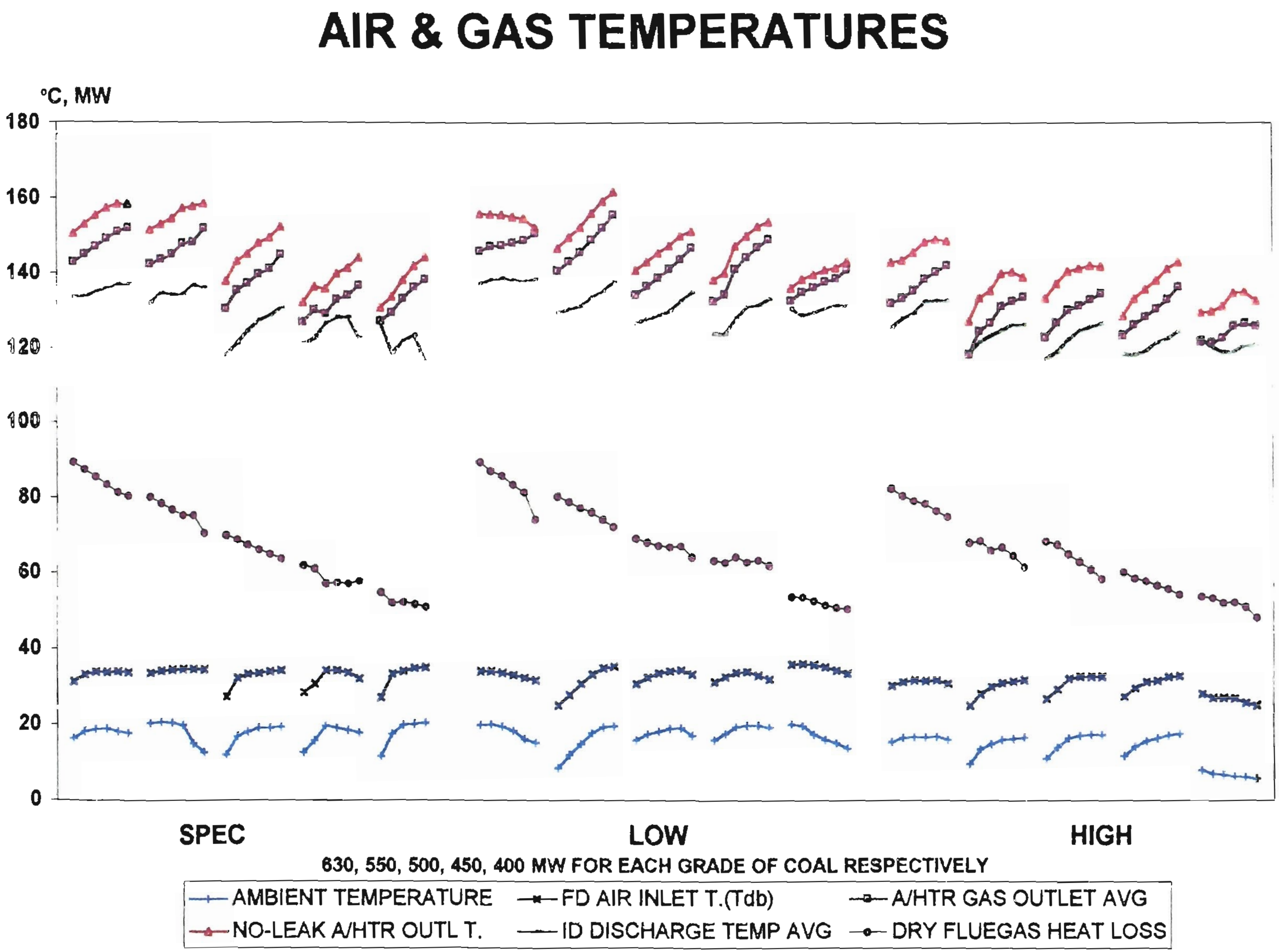


Figure 6.26: AIR AND GAS TEMPERATURES

6.4 RESULT EVALUATION AND COAL CHARACTERISATION

The results produced by the calculation process explained in this chapter, allowed guidelines to be defined for the optimum air flow (with accompanying oxygen in flue gas) for each of the loads and coal qualities. The maximum efficiencies (at the optimum air flows only) for the three different coal qualities are plotted on the same graph against units generated and air flow respectively in Figures 6.27 and 6.28. These graphs have highlighted an average difference of ± 0,5% between the optimum efficiencies of the spec. and low grade coals, and an average difference of ± 2% between the spec. and high grade coal efficiencies. It also showed an average difference of ± 2% between the efficiencies of the worst and the best loads on each coal quality. Figures 6.16, 6.17 and 6.18 also showed that the efficiency difference between the optimum and the worst air flow can exceed 1%. These differences are not negligible and savings in coal and generation sales would be significant.

The question was then raised, from a practical and operational point of view, how the operator would know what the coal quality would be at any point in time, so that the total air flow could be adjusted (by means of the panel Air/Fuel Correction facility), according to these guidelines? The CV Correction indication on the panel could not be used as guideline for the coal quality, since coal CV is not the only input for this value.

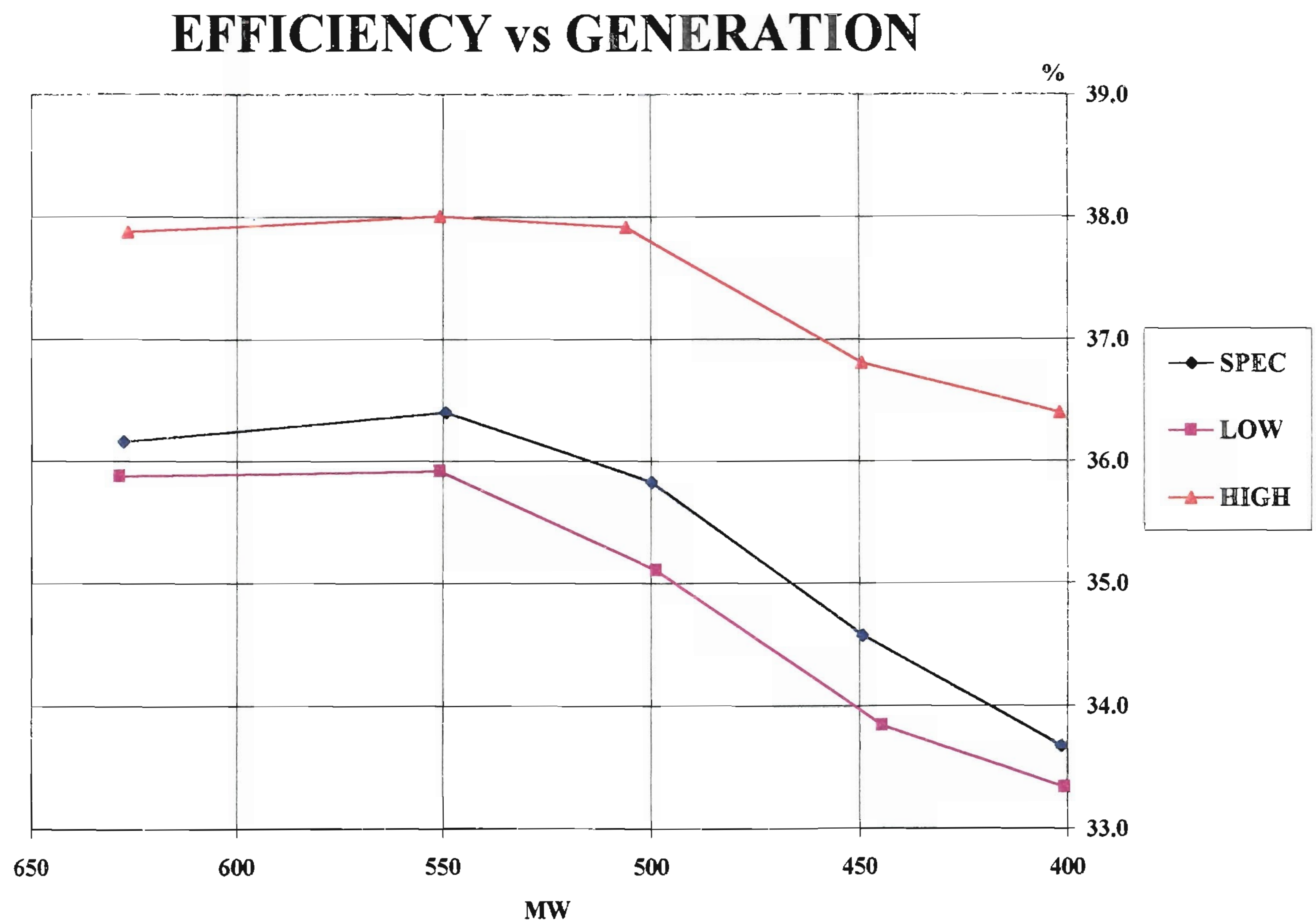


Figure 6.27: MAXIMUM EFFICIENCIES vs UNITS GENERATED

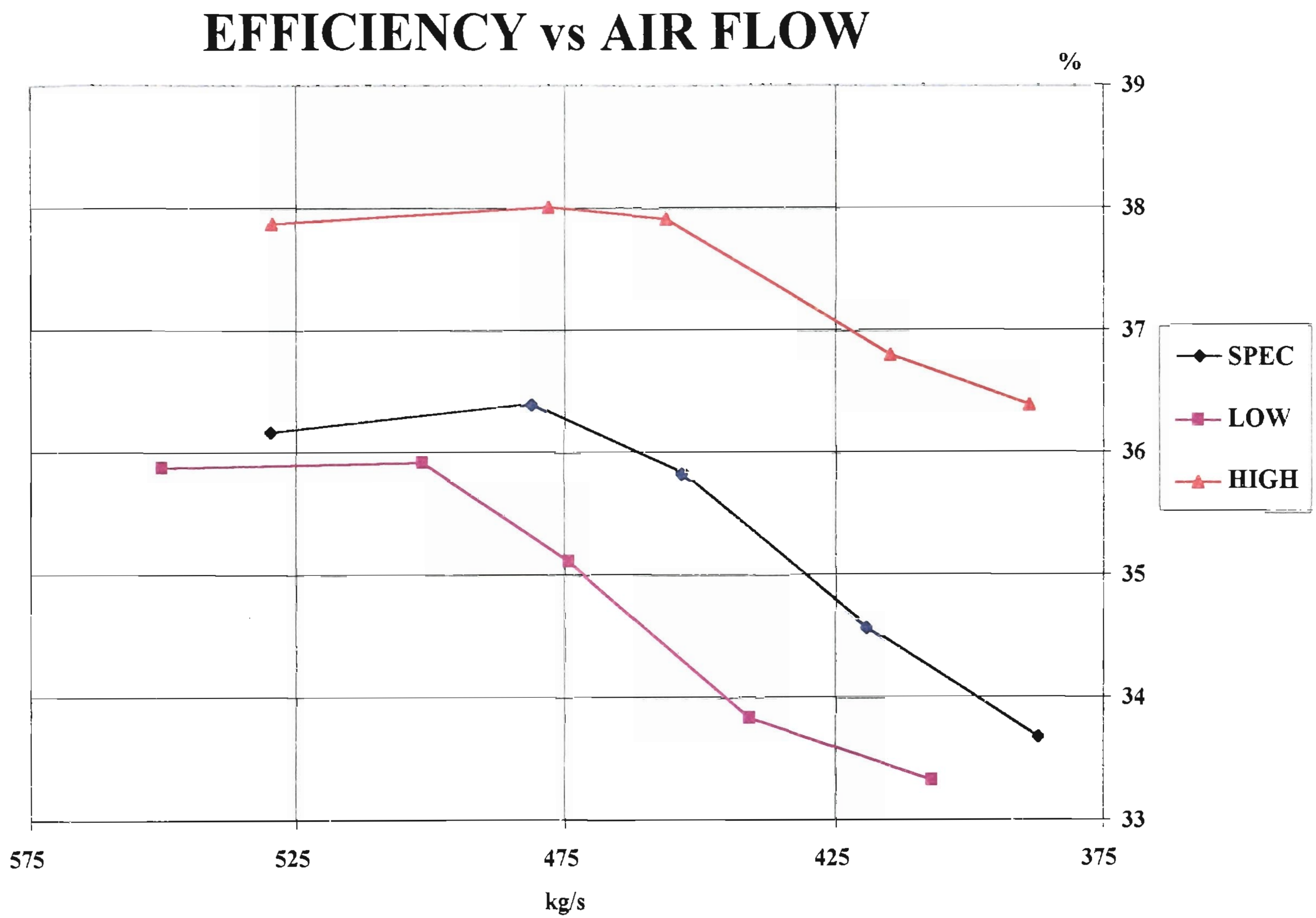


Figure 6.28: MAXIMUM EFFICIENCIES vs OPTIMUM AIR FLOWS

This reading is also a function of three variables: steam flow, PA flow and drum pressure. (Also see Chapter 3.5 for the discussion of the "boiler master controller" and Figure 3.23). Other variables such as how recently the furnace was sootblown would also produce a different value on the CV correction. These guidelines were also not based purely on CV, since the CV of the Low and Spec. grade coals were virtually equal, but significantly different optimum air flows and accompanying maximum efficiencies resulted, as mentioned above.

The solution offered was having the coal characterised according to these test results and to embark on a "blockburning" and segregated coal supply plan for Lethabo Power station. The author's recommendation from these test results is that it would be more advantageous not to blend the coal, but to supply it in the close margins of these qualities tested (Chapter 4.1.5, Figure 4.5 and Table 4.2).

The possibility should be explored to mine and supply the coal as Low and Spec. or High grade coal. This way it would be known in advance whether, Low grade coal would be supplied for a period of time. An operating instruction for that period of time could then be issued in advance, prescribing the optimum air flow and flue gas oxygen guidelines. The unit capability and boiler master controller, etc., could be set to suit, and this foresight could enable the operating to be adopted accordingly. Also, a wider range of coal from the mine could be utilised, positively influencing the life cycle costing for the power station and the mine. The coal contract clauses for bonuses and penalties should be revised, so as not to penalise the mine for supplying low grade coal for certain periods of time.

An important point that should be highlighted was the evidence that the maximum efficiencies with spec. coal, burnt at optimum air flows during these Unit 1 tests, were higher than the efficiencies during the equivalent Unit 2 tests[2] with blended coal of approximately the same CV. These Unit 1 tests' spec. coal was mined from the middle seam and then blended into the prescribed margin, where the Unit 2 test coal was a blend from an array of low, spec and high grade coal, having the same resulting CV. (E.g., The 550 MW tests had efficiencies of 35,9% for the low grade and 36,4% for the spec. grade coal, vs 35,0% for the Unit 2 test blended coal with spec. CV).

A blend of coal, consisting of low, spec. and high grade, can not distribute the air supply during the combustion process so that the spec. and high grade particles would only absorb the optimum air quantity, thus releasing the surplus air to the low grade that would need a higher amount for optimum. Unfortunately the blend of coal would experience that the spec. and high grade received more than optimum and the low grade received less than its optimum. That is also why a blending process can not simultaneously satisfy a target volatile content as well as the resulting weighted target CV. The required "blending" thus degrades to "mixing", and the seperate components combust individually. The author thus defined coal quality in two modes: The "Contamination" aspect, which dictates the CV of the coal, mainly caused by the amount of moisture and ash, and the "Reactivity" aspect, determined by the ratio of carbon to volatile content. Any "Clean Coal Technology" can thus only be applied to the coal to improve its heating value or CV, but unfortunately not to satisfy another condition for optimum air flow. By beneficiation the ash and moisture quantity could be improved, but the reactivity determines the optimum air flow, proved by the low grade and spec. grade coals in these tests having the same CV, but differing optimal air flows and resulting efficiencies.

These coal reactivity limits had to be redefined for Lethabo based on these test results. Initially, the comparisons in the figures that follow were made on a dry ash free basis (DAF), to eliminate any contamination effects, or gains that could have resulted from beneficiation. Figure 6.29 shows the CV vs total carbon. This scatter graph proved the above statements, since the Low grade coal showed the highest CV vs carbon content when evaluated on a DAF basis, but it performed the worst. An internationally accepted way that is often used to evaluate coal is by comparing the hydrogen content against the total carbon, DAF, (Figure 6.30, providing an initial indication of the aliphatic to aromatic nature of the organic matrix). By this method the spec. grade coal appeared as the coal with the best volatility, but the high grade coal had declined to the worst case, so this definition could not be the correct criterion.

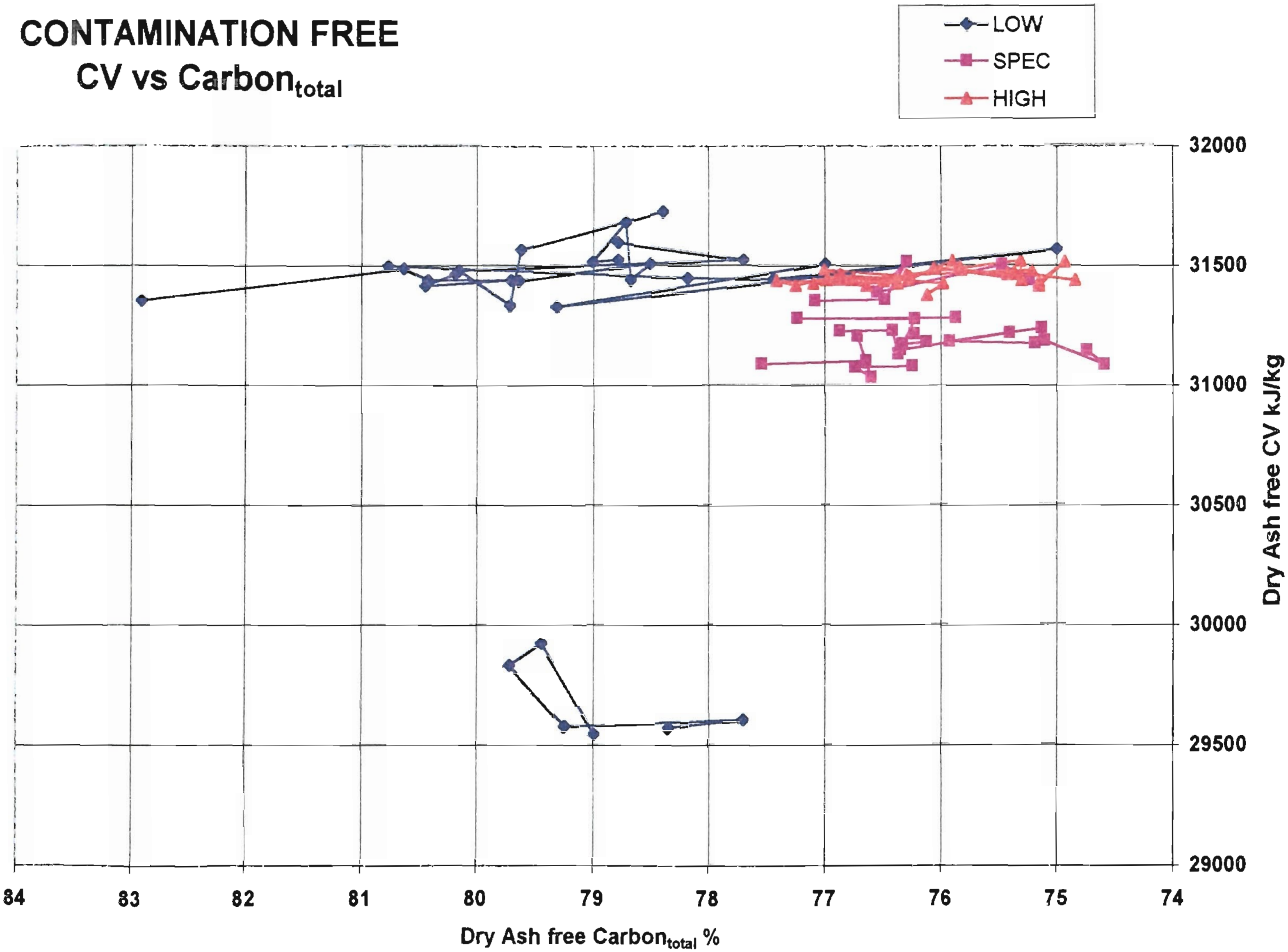


Figure 6.29: CALORIFIC VALUE vs TOTAL CARBON (DRY ASH FREE)

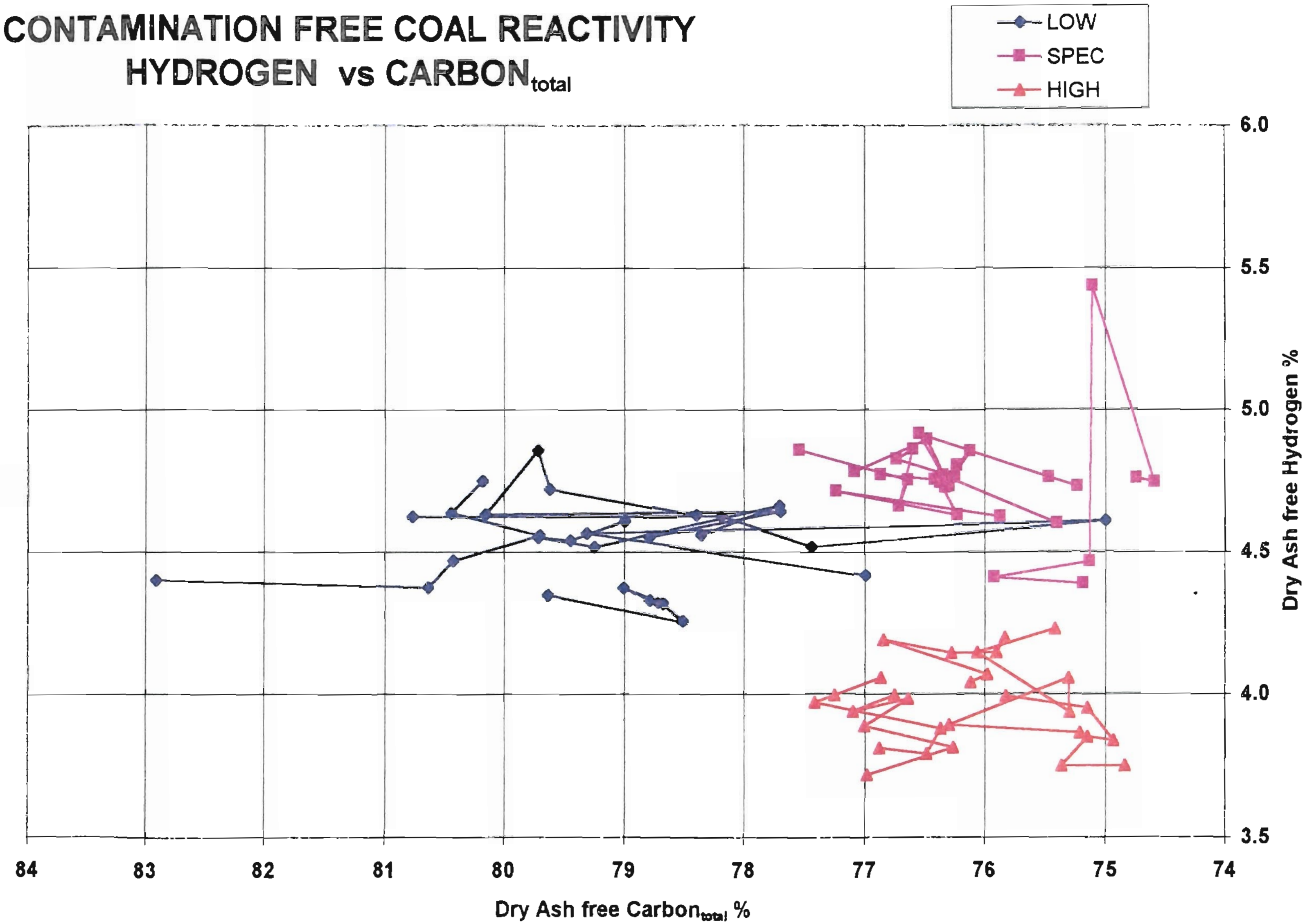


Figure 6.30: HYDROGEN vs TOTAL CARBON (DRY ASH FREE)

The total volatiles vs the total carbon gave a more significant image of the behaviour of these coals (Figure 6.31). With the contamination eliminated, the low grade coal still had the highest total carbon, but the spec. and high grade coals had advanced to display the best volatile content, significantly distinguished from the low grade. It was the authors opinion that total carbon is not the correct parameter to use in this type of evaluation, since some of the volatiles are also contained within that (C_xH_y type volatiles).

An evaluation of the total volatiles vs the fixed carbon only (**Figure** 6.32), seemed to be the comparison required. A clear division between the low grade coal relative to the spec. and high grade coal emanated. The spec. grade coal was also slightly superior to the high grade coal on this graph, meaning that the high grade was only less contaminated. A classification could then be formed for Lethabo coal concerning optimum air flow and operational and mining guidelines. (See Chapter 7 for the calculated ratio of carbon : volatiles and final recommendation). This graphical comparison would always have a linear relationship on a DAF basis since the remaining components displayed on the graph should always add up to 100%. A graph of only the active volatiles vs fixed carbon were compiled to test its value in this coal classification (**Figure** 6.33), but it can clearly be seen that Figure 6.32 would be preferred.

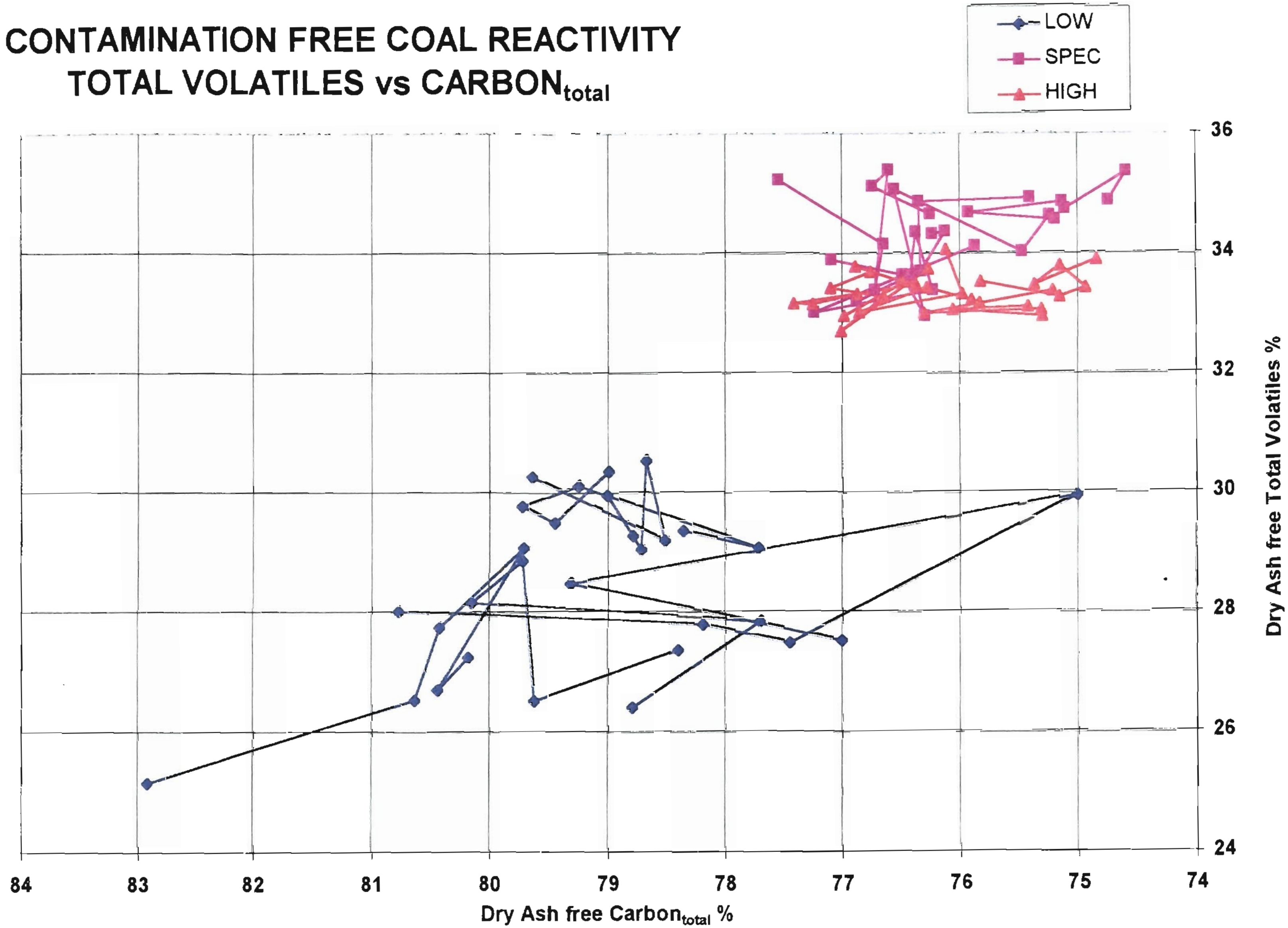
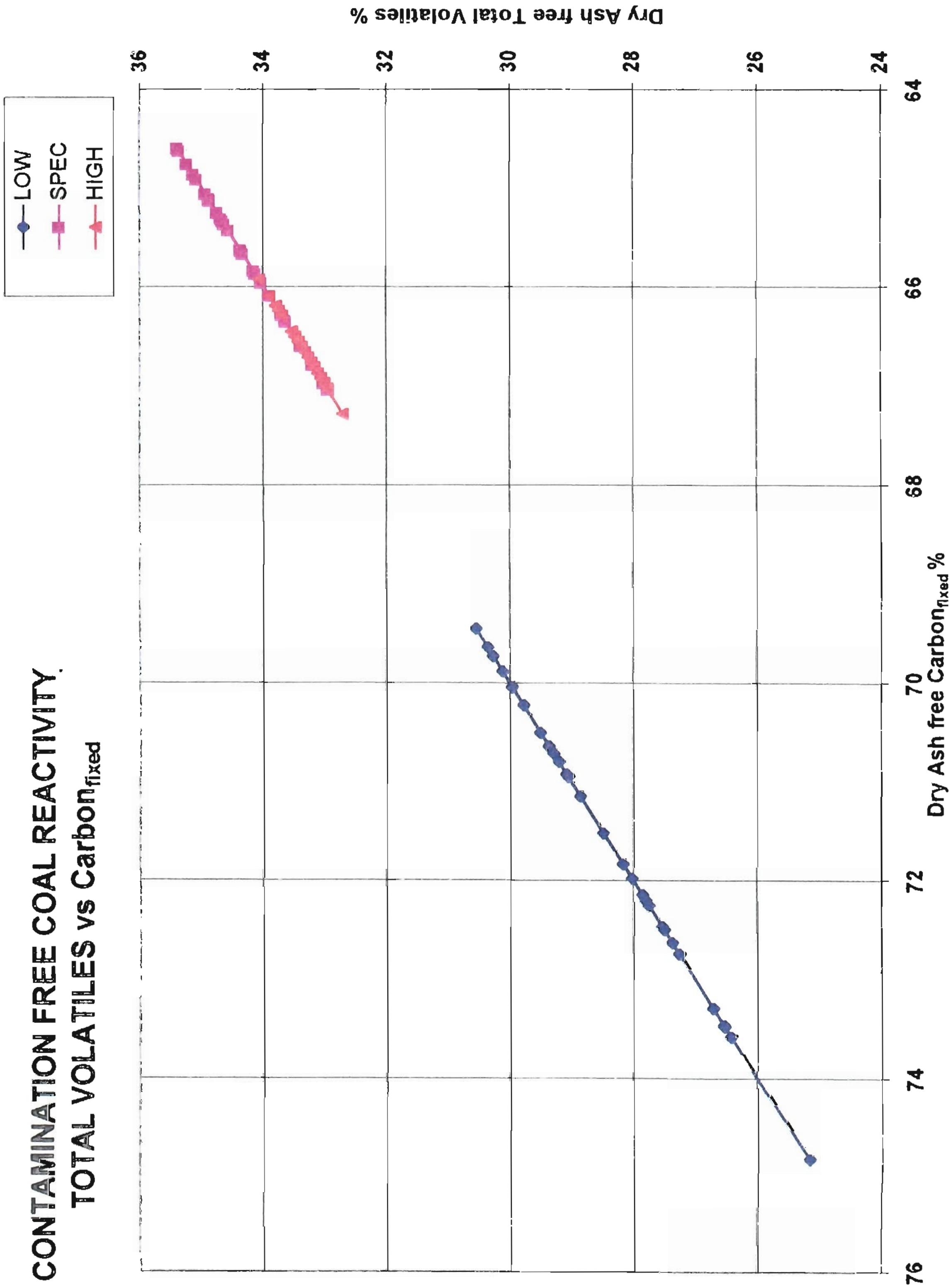


Figure 6.31: TOTAL VOLATILES vs TOTAL CARBON (DRY ASH FREE)

Figure 6.32: TOTAL VOLATILES vs FIXED CARBON (DRY ASH FREE)



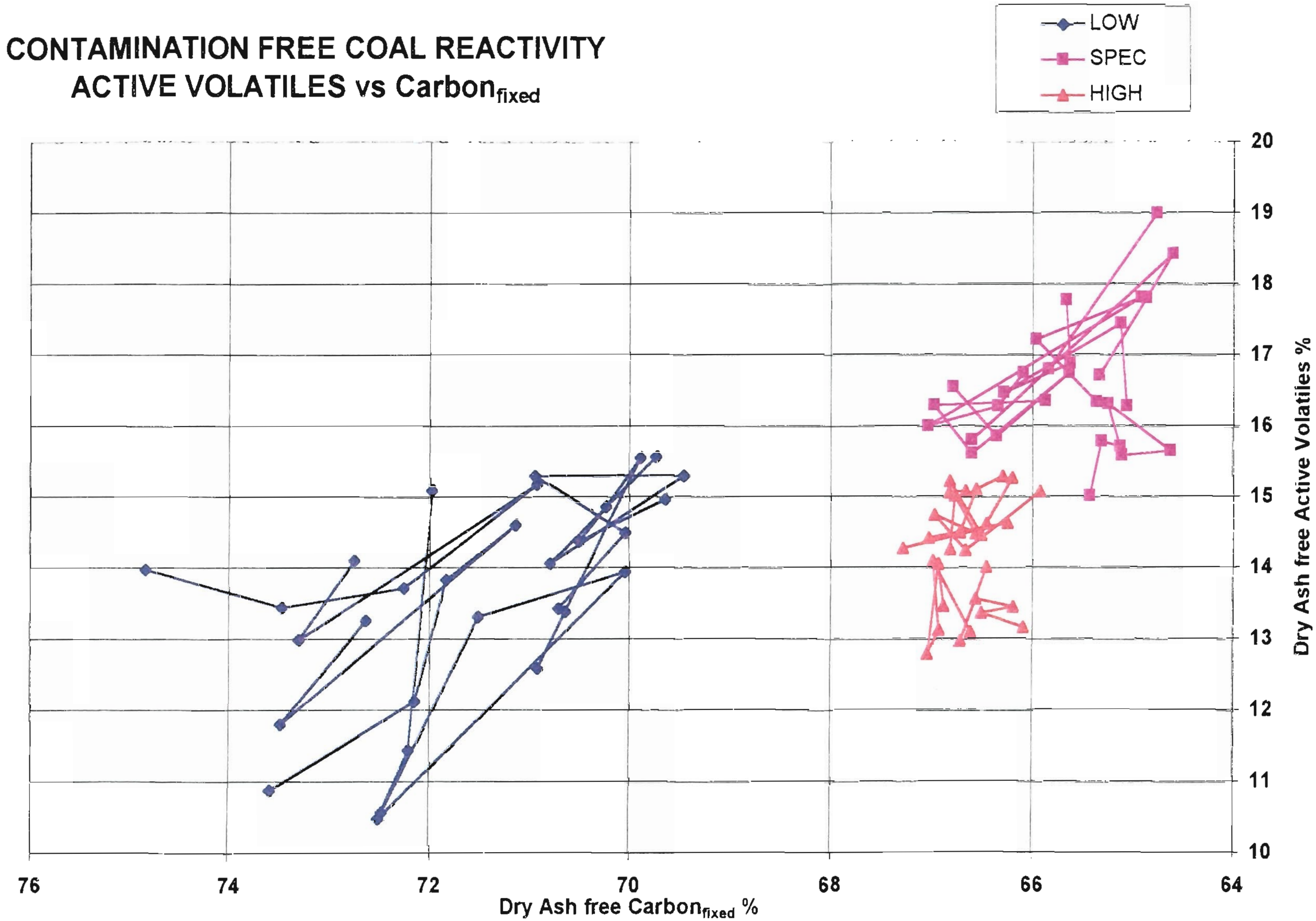


Figure 6.33: ACTIVE VOLATILES vs FIXED CARBON (DRY ASH FREE)

6.5 STEP PROGRAM CUSTOMISATION

STEP (Station Thermal Efficiency Performance) is the official computer program used in ESKOM since 1970. Appendix I, included in Volume II and based on Reference[33], describes the STEP System's background (Appendix I.1), the STEP philosophy (Appendix I.2), the system's attributes (Appendix I.3), the mechanism of how it operates with some of the main formulae (Appendix I.4), the system's shortcomings (Appendix I.5) and how this project and its results enabled the customisation thereof for Lethabo Power Station (Appendix I.6).

In summary it can be said that the STEP system utilises STEP factors to evaluate the plant performance. The overall STEP Factor is e.g.:

$$\text{STEP Factor} = \frac{\text{Actual Efficiency}}{\text{Target Efficiency}}$$

There are various STEP factors for all the losses as well. The target efficiency or losses are reflected by polynomials and correction factors which are functions of variables (Appendix I.4: Mechanism), such as load, coal quality, atmospheric conditions, etc. The target efficiency or losses slide with these variables, to enable the actual to be evaluated against prevailing conditions.

An efficiency program was needed in this project to enable optimisation, accommodate monitoring and evaluation, and exercise control over future implementation and developments. The STEP system was selected because it slides the targets, evaluates the whole unit simultaneously as opposed to the boiler and turbine separately and utilises the direct and indirect methods of calculation (Appendix I.3: Attributes). These principles were needed, since they highlight the features of this project that distinguished it from other conventional approaches.

Tests such as these (air flow optimisation with different coal qualities) can not be repeated or the resulting calculations exercised on a continuous basis at relatively short intervals (seconds or minutes) to monitor and maintain optimum operation. STEP serves this purpose, since it is tailored to accumulate large amounts of data.

The results of this project were used to customise STEP for Lethabo since no other suitable tests were performed previously. The previous contractual tests (boiler and turbine acceptance tests, etc.) supplied data that was based on isolated and not unitised behaviour. The optimum target values were thus not the ones that would satisfy optimum unitised behaviour. These shortcomings (Appendix I.3) of STEP (incorrect targets, etc.) could finally be addressed and in addition the existing philosophy enhanced. Improved correction and weighting factors were added to suit the process and coal characteristics, e.g., the carbon in ash target sliding with volatile content of coal and the more representative and accurate CV of coal calculated from the ultimate analysis (Appendix A, Sample calculation A.8). The combustion air flow was also highlighted as the most controllable variable that effects the efficiency of the whole plant the most significantly.

The STEP customisation process (Appendix I.6) addressed many aspects, but a selected few will be illustrated. It can be seen (Figure 6.34) that after the customisation process the overall STEP factors for all fifteen optimum air flow points were all equal and peaked at 99.219 %. The reason they were not 100 % (since these were now the new maximum overall efficiency targets) was that the turbine deterioration loss could not be eliminated and the real turbine blade condition prevailed during the tests. Note that whilst the accompanying actual efficiency curves (Figures 6.16, 6.17 and 6.18) had different values for the maximum efficiencies on the different loads and coal qualities, the accompanying STEP factors were equal. This is because a STEP factor must enable evaluation of performance on equal terms. The target efficiencies had thus now been corrected for load and coal quality, by sliding them accordingly.

For this customisation process the unaccountable losses had to be zero, resulting in the total accounted losses being minimum (0,728 %) at the maximum efficiency (optimum air flow) points, totalling 100 % with the direct side STEP factors. It should be noted that the maximum efficiency points were where the combined effect of all the losses was minimum. That was not necessarily the minimum value of any individual loss, but that value coinciding with the optimum air flow (maximum efficiency) was made to be the new target for each loss. Figures 6.35 and 6.36 show the individual boiler and turbine

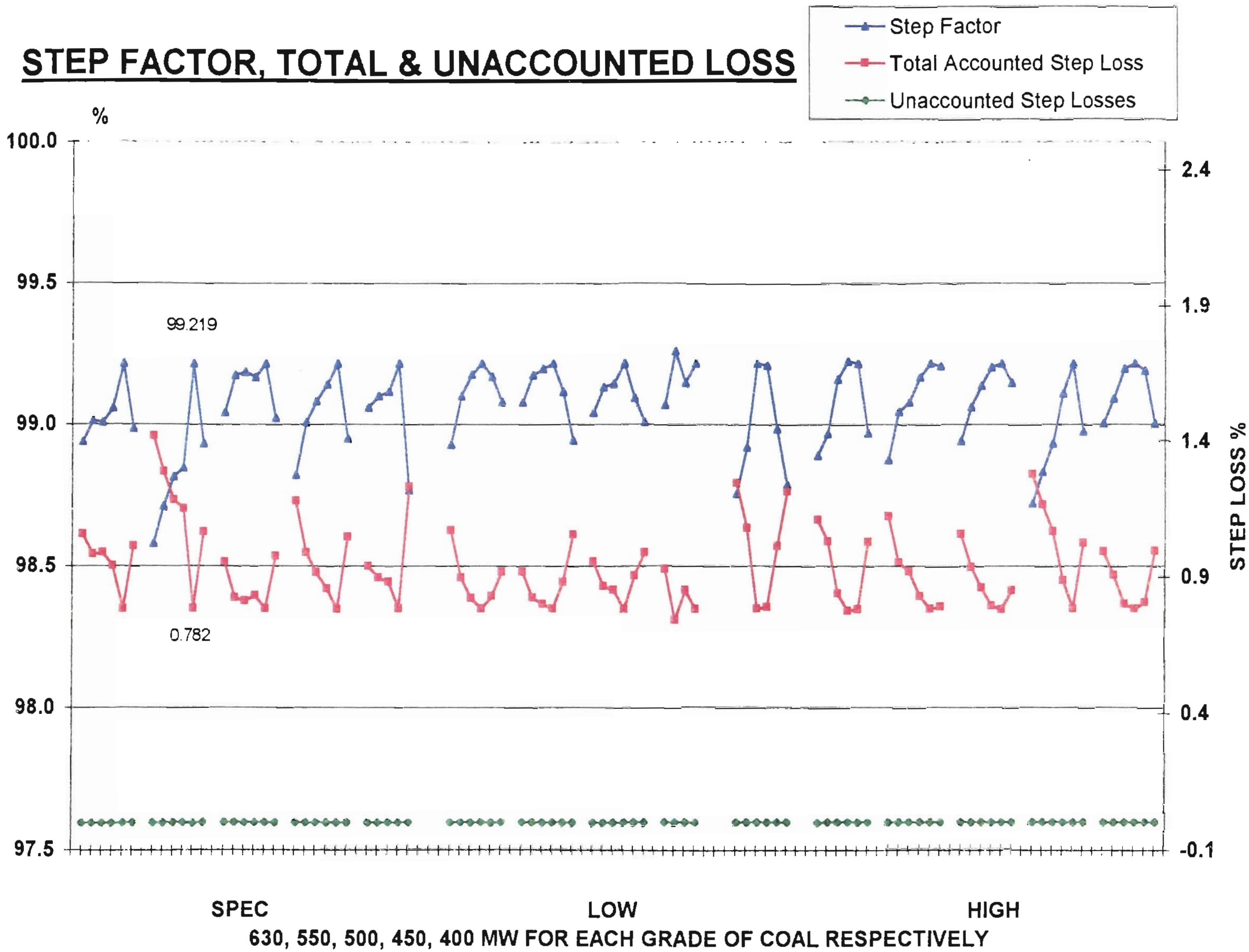


Figure 6.34: STEP FACTOR AND TOTAL UNACCOUNTED LOSSES

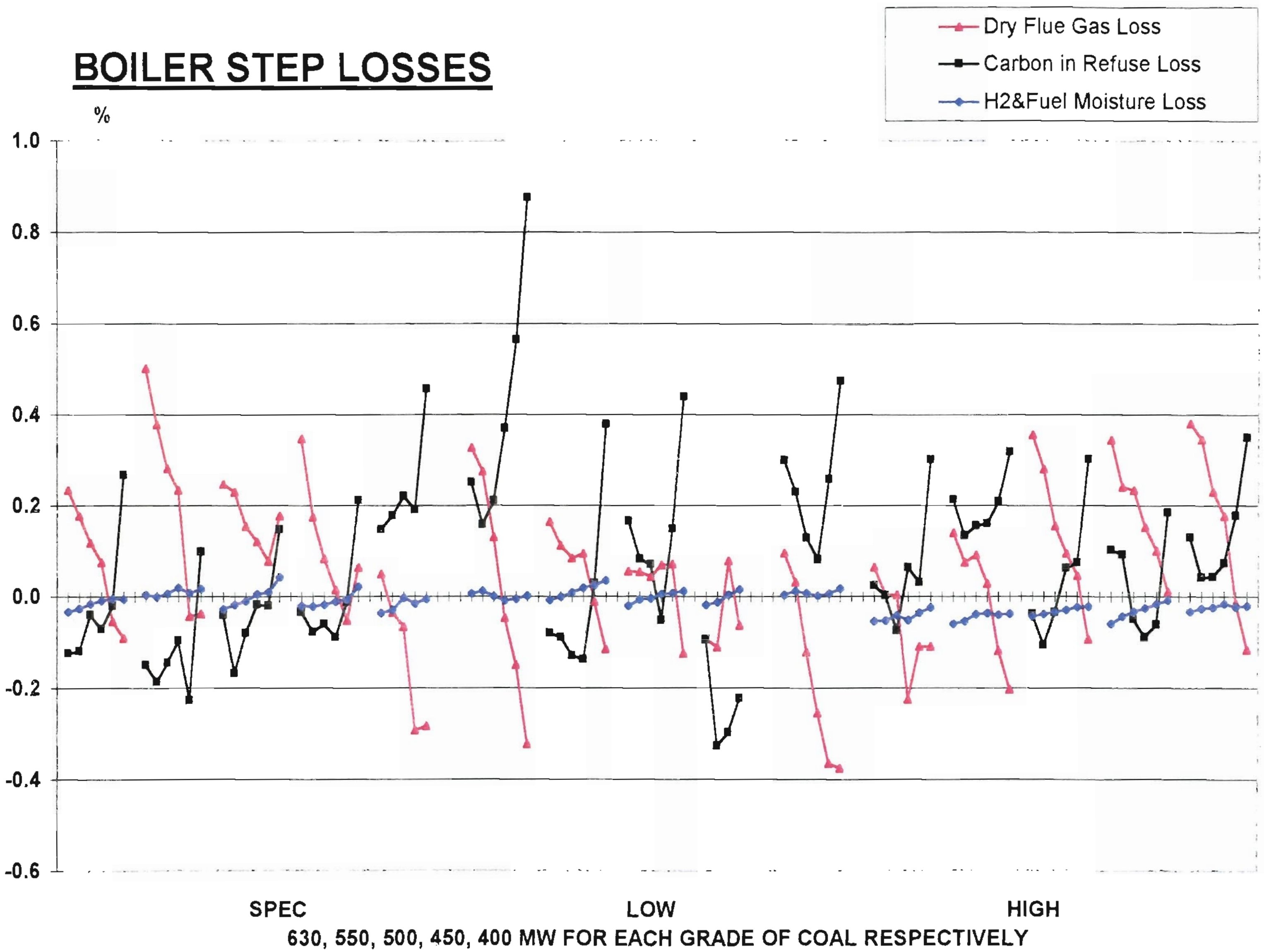


Figure 6.35: BOILER STEP LOSSES

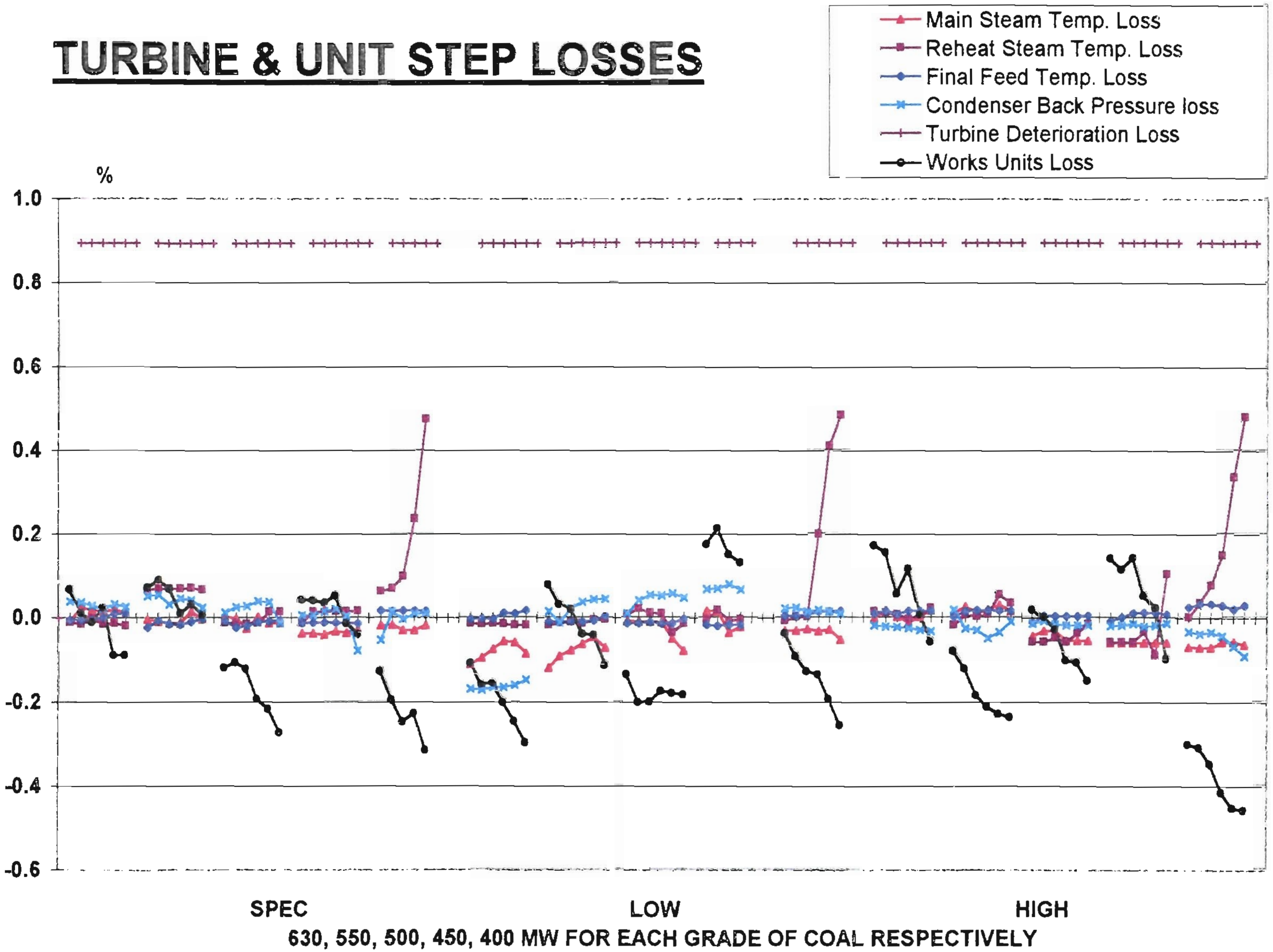


Figure 6.36: TURBINE AND UNIT STEP LOSSES

with unit losses respectively. Concerning the boiler STEP losses (Figure 6.35), it can be seen that the dry flue gas and carbon in ash had an opposing trend, which is correct, regarding the varying combustion air flow. The carbon in ash accounted loss was also higher in only one case (550 MW), which could be attributed to reasons other than air flow (mills, etc.), but in the other cases the loss values are in the same band, meaning that the volatiles correction factor was working correctly.

In the case of the turbine losses (Figure 6.36), the reheat steam temperature loss could be seen increasing at the low loads and low air flows, corresponding to the results in Figure 6.26. The Works Units loss had the correct trend (fan power dominating the downward trend in a load). It should be noted that some of the loads had shown a significant overall improvement on this loss. This was due to the unconventional milling combinations employed to ensure the pf fineness grading remaining as close as possible to being constant throughout, which was critical for this project. The works power target was defined with the correct milling combinations on each load. The overall evaluation of the losses and direct side STEP parameters thus gave proof of a representative and customised STEP program for Lethabo Power Station.
