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HIGH MASS FLUX COAL GASIFIER

Final Report

Phase III

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ABSTRACT

This report describes the design, analysis, construction and test activities associated with bringing a short residence time entrained flow gasifier Process Development Unit (PDU) to operational status.

The basic High Mass Flux (HMF) gasifier, incorporated in the PDU, operates at a coal throughput of twelve tons per day, a pressure of fifteen atmospheres and processes coal, oxygen and steam to produce a synthesis gas.

When applied to the production of Substitute Natural Gas (SNG), the option exists to add secondary coal to the basic HMF gasifier, for the purpose of enhancing the methane content of the product. A secondary coal feed system was developed and its injection capability demonstrated in a cold flow test facility.

Operability and performance of the synthesis gas stage of the HMF gasifier were demonstrated with Pittsburgh seam coal and North Dakota Lignite. Curtailment of testing precluded the conduct of any gasification tests with secondary coal injection.

Included in the main program was a task to evaluate the effects of slag fluxing additives upon viscosity/temperature relationships for Pittsburgh seam coal slags. The testing associated with this task was conducted by the Alfred University Research Foundation (AURF).

1.0 EXECUTIVE SUMMARY

Primary objectives of this program were to evaluate the High Mass Flux (HMF) entrained flow gasifier as a producer of synthesis gas, using Pittsburgh seam coal, oxygen and steam and, to evaluate the operation and performance of the HMF gasifier with secondary coal injection.

The gasifier was designed to process 0.5 ton of pulverized coal per hour and to operate at a pressure 220 psia. For design purposes, a nominal adiabatic reaction temperature of 2500°F was selected.

Gasifier sizing studies resulted in the selection of a residence time of nominally 220 milliseconds for the synthesis gas stage of the gasifier and a residence time of 280 milliseconds for the secondary coal reaction zone.

A modular type gasifier was designed and fabricated. Instrumentation sections were located at the exit from the synthesis gasifier section and at the exit from the secondary coal reaction zone. At the instrumentation sections, gasifier reaction temperatures were measured and water-cooled gas sample probes were installed.

Heat and material balance computer programs, developed by Bell, were used to perform gasifier parametric performance analyses.

The effects of oxygen/coal, steam/coal and carbon conversion efficiency variations upon gasifier performance were evaluated and desirable operating conditions for the synthesis gas section of the gasifier were identified.

Potential effects of secondary coal injection upon overall performance of the gasifier, when used for the production of SNG, were evaluated. This study identified that, at appropriate secondary coal/primary coal flowrate ratios and at secondary coal carbon conversion efficiencies of approximately seventy-five percent, very significant efficiency improvements in SNG production efficiency are achievable.

A study to evaluate the effects upon operation and performance of different coal transportation gas options showed nitrogen to be a convenient gas for coal tank pressurization and coal transportation in the current R&D process development unit (PDU). For commercial applications however, carbon dioxide would be a better choice. A mixture of carbon monoxide and hydrogen should be used as an accelerating gas for secondary coal injection.

The existing gasifier test facility was upgraded by the addition of a pressurized slag collection tank, a cyclone separator and char collector tank, a condenser and collector tank and an on-line mass spectrometer. Each of these additions were made to improve the data collection capability of the PDU and to facilitate the acquisition of accurate material and heat balances.

In the interest of safety and to enhance PDU reliability, a programmable logic controller (PLC) was installed in the control console to automatically execute PDU startup and shutdown. In addition, the PLC continuously monitored key parameters and, in the event of pre-set criteria being violated, activated an audio/visual signal or, in the event of an emergency, executed automatic shutdown.

P

A subprogram was conducted to develop a system for secondary coal injection. Design studies identified the need for four-way splitting of the secondary coal feed, and the requirements for coal feed velocities and secondary coal injection velocities. A four-way coal splitter and secondary coal injection system was built and installed in a cold flow test facility. Following initial coal splitting problems, successful four-way flow splitting was demonstrated and uniform secondary coal injection and distribution within a simulated reactor section was achieved.

A subcontract was let to AURF to investigate the effects of fluxing additives upon slag viscosity in the gasifier operating temperature range. It was planned to use a fluxing agent during the HMF gasifier test program only if slag flow problems were encountered. The slag fluxing program identified that additions of small percentages of sodium oxide, calcium oxide and borax had the effects of reducing the slag viscosity. In the case of calcium oxide addition, good agreement was achieved with an equation developed by Watt and Fereday which predicts slag viscosity for a given slag composition. Application of this equation to higher calcium oxide additions than used during the test program indicates that very significant viscosity reductions are achievable.

To conduct the originally planned gasification test program would have required additional contract funds. In consequence, Bell undertook to conduct a reduced scope test program at its own expense. The Bell funded program consisted of tests with the gasifier synthesis gas section only. Seven gasification tests of up to thirty minutes duration were conducted during which four configurations of gasifier were evaluated and operation with Pittsburgh seam coal and North Dakota Lignite was demonstrated.

Following the resolution of some startup problems, operation and performance of the HMF gasifier and PDU were very satisfactory. The data acquisition systems worked well. There was evidence of some water and fly ash loss from the material collection system during some of the tests; however, after correcting for these losses very satisfactory material balances were obtained. Modifications to condensate removal procedures and the addition of a fly ash bag collector system should remove the necessity for material balance correction.

2.0 CONCLUSIONS

2.1 PROCESS DEVELOPMENT UNIT (PDU)

Fabrication and checkout of a PDU, which incorporates a twelve-ton per day, short residence time, entrained flow gasifier and advance data collection and PDU control systems, was completed.

2.2 PARAMETRIC PERFORMANCE ANALYSIS

Analysis indicates that, in an SNG application, the addition of a secondary coal injection stage, to the HMF gasifier, offers the potential for a very significant increase in overall plant efficiency.

2.3 SECONDARY COAL INJECTION

A secondary coal injection system was designed and tested in a cold flow test rig. Satisfactory four-way splitting of a dry, dense phase, pulverized coal stream was achieved and uniform coal distribution, within a cold flow simulated gasifier, was demonstrated. Due to curtailment of the gasification test program, no gasification tests with secondary coal injection were performed.

2.4 SLAG FLUXING TESTS

The effect of adding each of the three fluxing agents (sodium oxide, calcium oxide and borax) to Pittsburgh seam coal slag was to reduce the viscosity in the operating temperature range of the gasifier. In the case of calcium oxide additions, good agreement was obtained between measured viscosity/temperature relationships and those predicted by the Watt-Fereday equations. Use of the Watt-Fereday equations, beyond the range of additions tested, indicates that the temperature at which a viscosity of 200 poise pertains could be reduced from approximately 1440°C (2624°F) to 1110°C (2030°F) by increasing the calcium oxide content of the slag to approximately twenty-five percent. Should slag flow problems be encountered in an entrained flow gasifier, the addition of a fluxing agent appears a very feasible solution.

2.5 GASIFICATION TESTS

Seven gasification tests of up to thirty minutes duration were completed under company sponsorship. Satisfactory operation and performance was demonstrated using both Pittsburgh seam coal and North Dakota Lignite.

Modification of the condensate removal procedure and addition of a bag filter, to collect fly ash, should enable overall and major element material balances of better than $\pm 5\%$ to be achieved without the application of corrections for water carry over and fly ash loss.

The HMF gasifier PDU, which operates at a throughput of twelve tons of coal per day, is operational and ready for use to resolve many of the generic technical issues associated with advanced entrained flow gasifiers.

3.0 RECOMMENDATIONS

There are a number of technical issues which must be resolved before the entrained flow gasifier can achieve its full commercial potential. Some of these issues are:

- Gasifier Liner Durability**
- Carbon Conversion and Oxygen Consumption**
- Scaling to Commercial Size**
- Operability and Safety**
- Gasifier Related Equipment Development**

The High Mass Flux Gasifier PDU and Bell's supporting capabilities are very well suited to the conduct of the basic R&D required on each of these items.

It is recommended, therefore, that the operational HMF gasifier PDU be utilized to address these important technical issues which are generic to advanced entrained flow gasifiers.

4.0 PROGRAM PLAN

4.1 OBJECTIVES

The overall objective of this program was to evaluate the High Mass Flux Gasifier for use in the production S.N.G. For this specific application a secondary coal injection stage is added to the basic oxygen blown entrained flow gasifier. This addition results in an enriched methane yield and reduced oxygen and steam consumption.

Specific objectives for the initial phase of development reported herein were:

- Demonstrate the feasibility of the Bell HMF Gasifier as a viable reactor for efficient production of synthesis gas in a system using bituminous coal, oxygen and steam.
- Evaluate the feasibility of injecting secondary coal as a means of producing a methane enriched gas.

To accomplish these objectives a program comprised of the following major tasks were defined.

- Design and construct a 0.5 ton of coal per hour, 220 psia, coal gasifier with a secondary coal injection stage.
- Modify the existing gasifier test facility to incorporate a pressurized slag tank, cyclone and condenser. These additions were required to facilitate collection and/or measurement of all reactor products and to effect a material balance closure.
- Conduct a cold flow test program to develop a secondary coal injection system.
- Perform studies and experimentation to investigate the use of fluxing additives in the control of viscosity characteristics of coal slag.
- Conduct gasification tests to demonstrate the feasibility of the HMF gasifier as an efficient producer of synthesis gas and to evaluate secondary coal injection.

During subsequent phases of the program it was planned to evaluate methane generation at higher pressure (up to 750 psia) and to demonstrate the gasification process during continuous duration tests.

4.2 TEST PROGRAM

4.2.1 Secondary Coal Injector Development

The objective of the secondary coal injection test program was to develop an injection system for use during the final series of gasification tests.

The plan was to analyze and evaluate secondary coal injection concepts using a coal particle trajectory model and prior gasifier test experience. Evaluation criteria were:

- P
- Coal Mixing
 - Uniform Coal Distribution
 - No Injector Plugging or Deleterious Slag Accumulation

Design concepts were to be selected, fabricated and subjected to cold flow test evaluation.

It was anticipated that at least one of the selected concepts would have more than one coal injection element and coal flow splitting would be required. Coal splitting tests were planned to be conducted in a test facility fabricated at Bell under New York State ERDA sponsorship.

Following satisfactory splitting tests, the secondary coal injection system was to be assembled into a reactor, comprised of residual hardware from the air-blown and IR&D test programs, and tested in a cold flow test rig.

Based upon these cold flow test results, the secondary coal injector to be used for gasification tests was to be selected.

This task was initiated under contract and completed using company funds following program redirection.

4.2.2 Material Test Program

Slagging problems were experienced during the DOE sponsored air-blown High Mass Flux Gasifier Test program and were partially resolved. During the Bell sponsored IR&D program, injection system modifications appeared to have essentially eliminated slagging problems. It was considered prudent, however, to give a thought to potential slagging difficulties and it was planned to conduct a modest program to investigate methods of reducing the viscosity of Pittsburgh seam coal slag by means of fluxing additives. This task was completed in accordance with the plan.

4.2.3 Gasification Test Series

A total of approximately thirty gasification tests were planned to be conducted during this initial phase of the program. The coal flowrate was nominally 0.5 ton per hour and the reactor operating pressure was approximately fifteen atmospheres.

The test program was to be divided into four segments.

The initial test segment of approximately eight tests was to check out the reactor and facility and lead to the selection of the primary oxygen and coal injection system.

During the second series of four tests the effects of changing the position of the steam injector were to be evaluated.

The main body of planned gasification tests was comprised of a series of approximately fourteen tests over a range of oxygen to coal and steam to coal mixture ratios. These tests were to be conducted with the reactor configuration selected following the initial two test series. Approximately ten of the tests were to be of one hour duration.

The fourth and final series of tests planned were with the secondary coal injector added. Approximately four tests were to be conducted during which primary zone coal, oxygen and steam flowrates were to be maintained essentially constant and four different secondary coal flowrates would be evaluated.

The planned gasification test program is summarized in Figure 4.2.1.

1. Sequence and Equipment Checkout and Injector Variables
 - Solid grain initiation test.
 - Approximately three checkout gasification tests (5 - 10 min.).
 - Four tests with different injector conditions.
2. Steam Injector Variables
 - Two tests with steam injector upstream of water cooled cylindrical section.
 - Two tests with steam injector downstream of water cooled cylindrical section.
3. Oxygen/Coal and Steam/Coal Ratio Variations
 - A total of fourteen tests over a range of O_2 /coal and steam/coal ratios (approximately 10 tests of 1 hour duration).
4. Secondary Coal Injection Tests
 - Four tests at selected constant upstream O_2 /coal and steam/coal ratios and different secondary coal flowrates.

Figure 4.2.1. Original Gasification Test Plan Summary

4.3 PROGRAM SCHEDULE

Development of the High Mass Flux Gasifier for the production of S.N.G. was contractually initiated on September 30, 1979.

The program schedule (Figure 4.3-1) indicates that, during the first six months of the program, reactor and test facility analysis, design and fabrication activities were planned to be conducted. During this time frame, work was to be initiated on cold flow tests, to develop a secondary coal injection system, and tests to evaluate the effects of the addition of fluxing agents upon slag viscosity. Gasifier testing was scheduled to begin in April 1980 and to continue through mid-September.

Problems encountered during PDU construction delayed the initiation of checkout tests until June 1980 and resulted in the need for additional funds to complete the planned gasification test program. The DOE and GRI elected not to fund this work. A test program of more limited scope was therefore conducted by Bell between September and December, 1980. In addition, some coal flow work to demonstrate the modified four-way splitter was conducted in August and September under Bell funding.

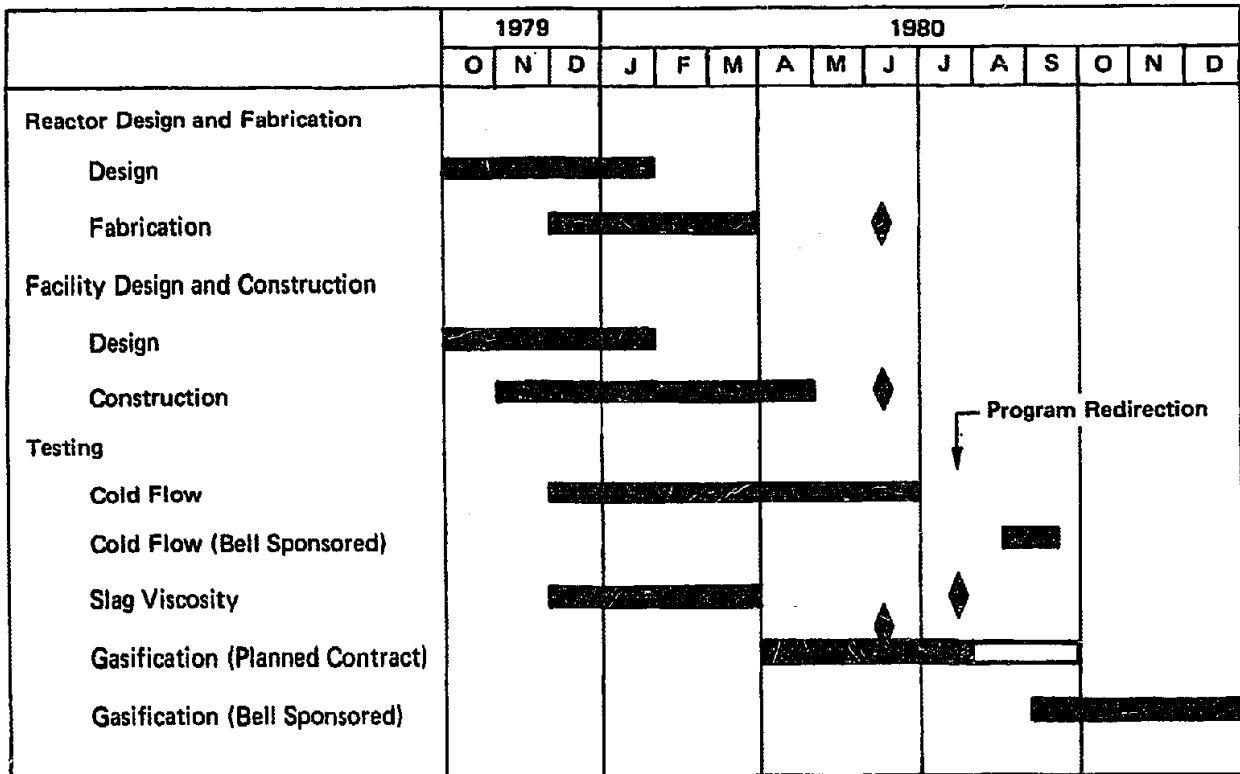


Figure 4.3-1 Program Schedule

5.0 TECHNICAL PROGRESS

5.1 PROCESS DESCRIPTION

The basic gasification process planned for development under this contract is carried out in an entrained flow gasifier and may, for simplicity, be considered as taking place sequentially in four zones. Separation of the zones is a consequence of the location of the reactant injector elements and their resultant mixing patterns. These reaction zones are identified in Figure 5.1-1.

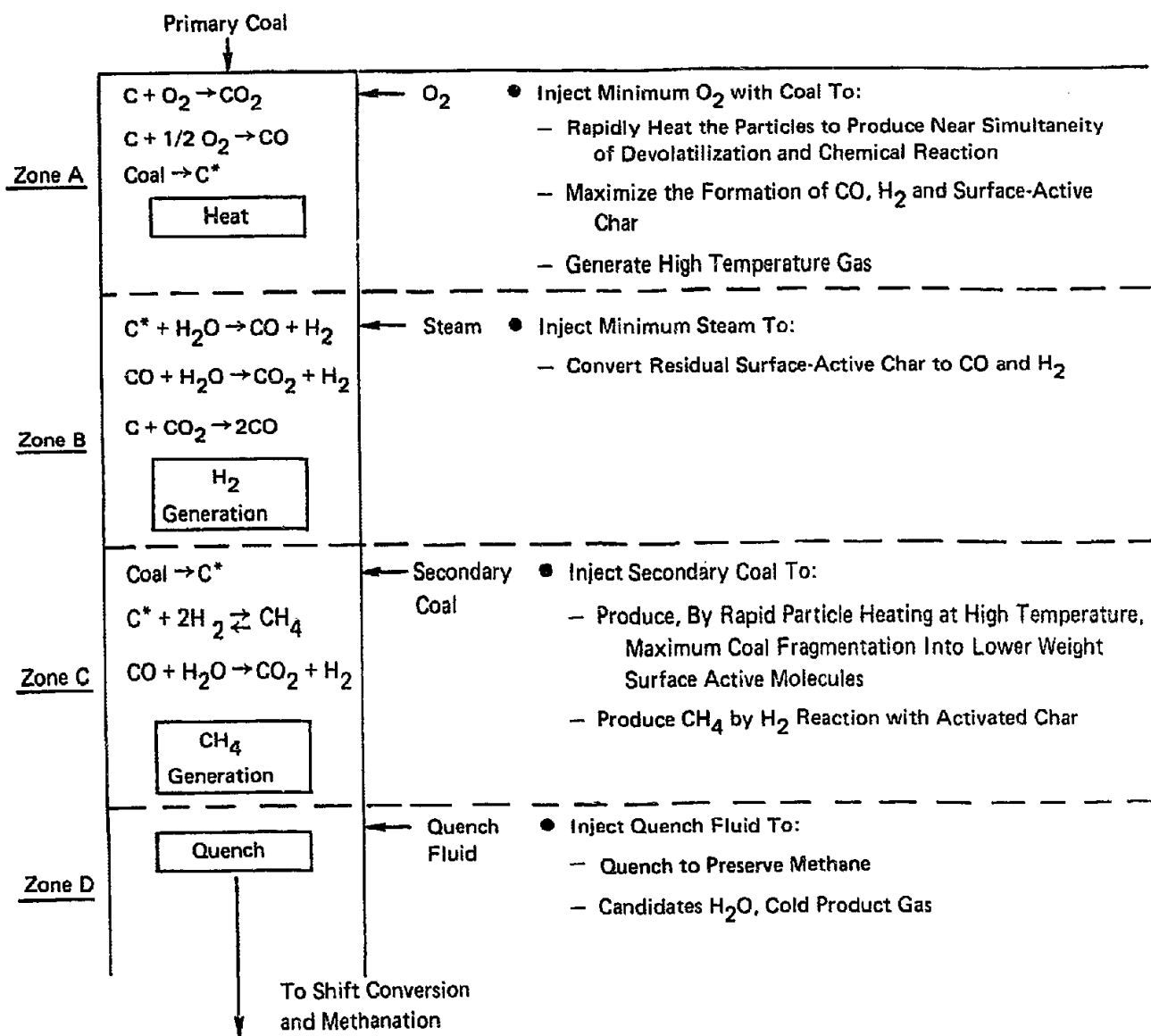


Figure 5.1-1 High Mass Flux Gasification Process for Enhanced Methane Yield

Zone A – In this zone, finely divided coal is reacted with oxygen in a fast, highly exothermic reaction, which produces CO and CO₂, a high temperature (≈ 3000°F), rapid devolatilization of the coal particles, and the formation of a char with chemically active sites.

Zone B – This is a zone of intense mixing which is downstream of Zone A and in which reactions are induced by the interaction of injected steam with the hot gases produced in Zone A. The hot, active char reacts with steam in an endothermic reaction which produces CO and H₂. The reaction proceeds until the char is essentially consumed and the temperature drops to approximately 2500°F.

Zone C – Essentially a uniform mixture of H₂, CO, CO₂, and H₂O flows downstream in the reactor from Zone B to Zone C, where it contacts secondary coal injected into the gas stream. The secondary coal mixes with the gas and is rapidly heated and devolatilized to produce a chemically active char which reacts with the gases from Zone B and the devolatilization products. Methane is formed in a kinetically controlled reaction between the hydrogen and the active sites in the char as well as from pyrolysis of the coal volatiles.

Zone D – In order to minimize decomposition of the kinetically formed methane, the gases are quenched rapidly in Zone D by injecting water.

5.2 PERFORMANCE ANALYSIS

Utilizing a heat and material balance computer program, developed by Bell, parametric performance analyses were performed to:

- I. Establish the effects of primary variables upon the performance of the HMF gasifier in the synthesis gas configuration, i.e., Zone A/Zone B only.
- II. Establish the potential effects of secondary coal injection upon performance of the HMF gasifier in a SNG application.
- III. Evaluate the effects upon operation and performance of different coal transportation carrier gas options.

5.2.1 Zone A/Zone B Performance Analysis

The majority of gasifier tests planned for the subject initial phase of the HMF gasifier development program were without secondary coal injection. The heat and material balance computer program was, therefore, used to predict equilibrium gasifier performance for the gasifier in the synthesis gas configuration, i.e., Zone A/Zone B only.

Principal program input variables are:

Coal:	Type (composition), Flowrate, Temperature
Oxygen:	Purity, Flowrate, Temperature
Steam:	Flowrate, Temperature
Gasifier:	Carbon Conversion Efficiency, Pressure, Heat Loss

Primary output quantities characterizing gasifiers performance are:

- Gas composition
- Gas temperature
- Cold gas efficiency
- Specific oxygen consumption
- Specific steam consumption

Computer runs were made to evaluate the effects of input variables. Inputs used for these analyses were:

Coal:	Type	—	Pittsburgh Seam No. 8
	Flowrate	—	100 lb/sec (for convenience)
	Temperature	—	77°F
Oxygen:	Purity	—	99.6%
	Flowrate	—	Variable
	Temperature	—	77°F
Steam:	Flowrate	—	Variable
	Temperature	—	600°F
Gasifiers:	Carbon Conversion η	—	70% - 100%
	Pressure	—	15 atm
	Heat Loss	—	0

A set of results are presented which show the effects of oxygen/coal and steam/coal ratio variations upon gasifier performance. Since the results presented reflect 100% carbon conversion efficiency, no reactor heat loss and thermodynamic equilibrium, they represent ideal performance for the gasifier in the synthesis gas configuration.

To the left of the "Soot lines" shown in Figures 5.2-1 through 5.2-4, solid carbon remains in the product gas. To the right of the line all carbon is theoretically gasified and is therefore, the area in which the gasifier should be operated.

In order to achieve high carbon conversion efficiencies in a short residence time entrained flow gasifier, it is necessary to operate in the 2500°F to 3000°F temperature range and in the interest of maximizing cold gas efficiency and minimizing specific oxygen consumption, it is desirable to operate as close to the "Soot line" as possible. A desirable zone of operation is thus defined and a range of associated performance values identified.

Actual carbon conversion efficiencies experienced in practice will of course modify these results and the computer model was used to evaluate this effect. An approximate assessment of the effect of carbon conversion efficiency variations can be obtained, however, by dividing the oxygen and steam feed ratios for 100% carbon conversion efficiency by the carbon conversion efficiency of interest and entering these ratios into Figures 5.2-1 through 5.2-5.

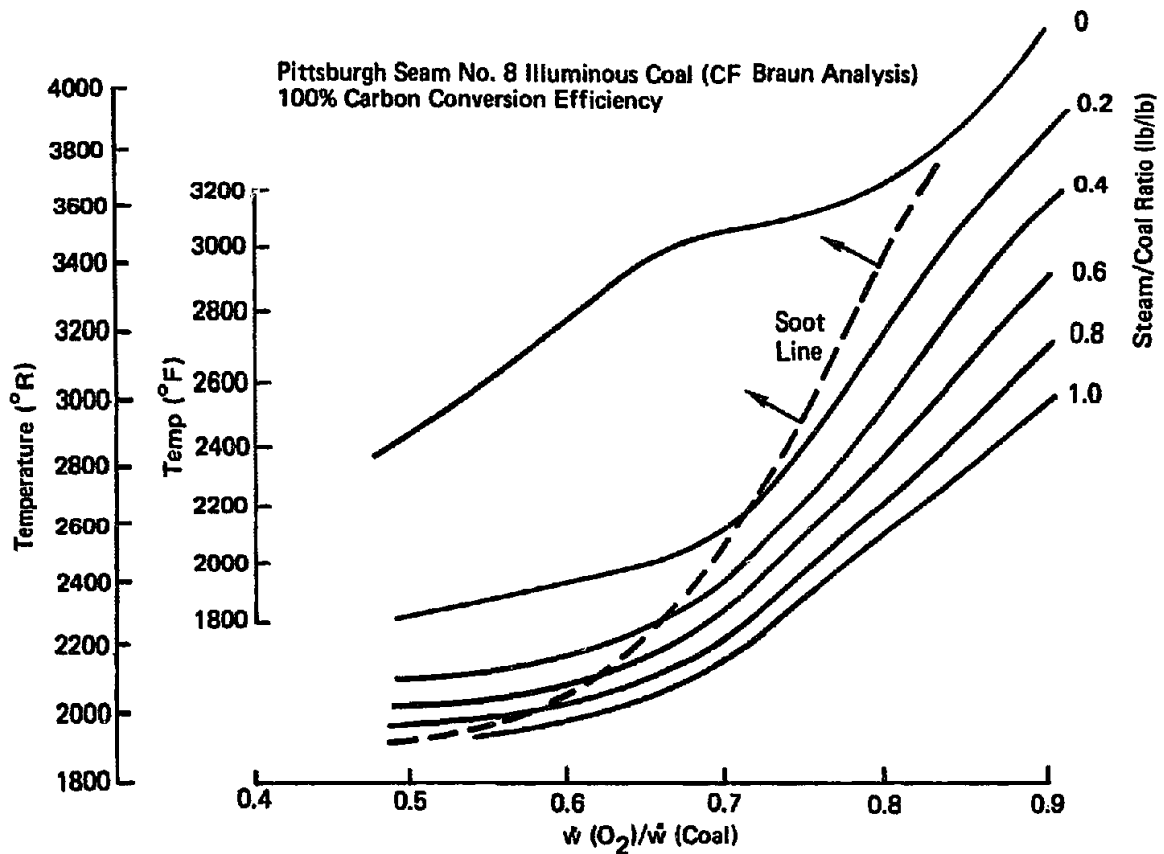


Figure 5.2-1 Effect of Oxygen/Coal and Steam/Coal Mixture Ratio Upon Gasifier Adiabatic Equilibrium Temperature

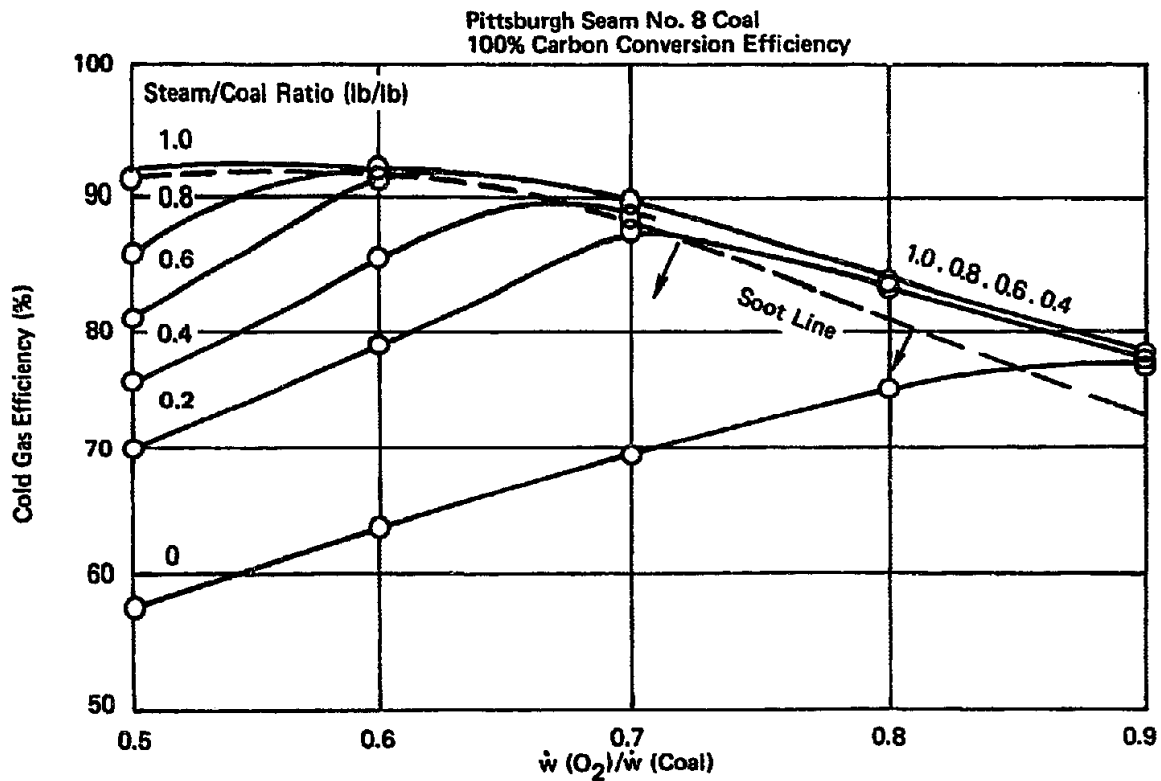


Figure 5.2-2 Effect of Oxygen/Coal and Steam/Coal Mixture Ratio Upon Gasifier Adiabatic Cold Gas Efficiency

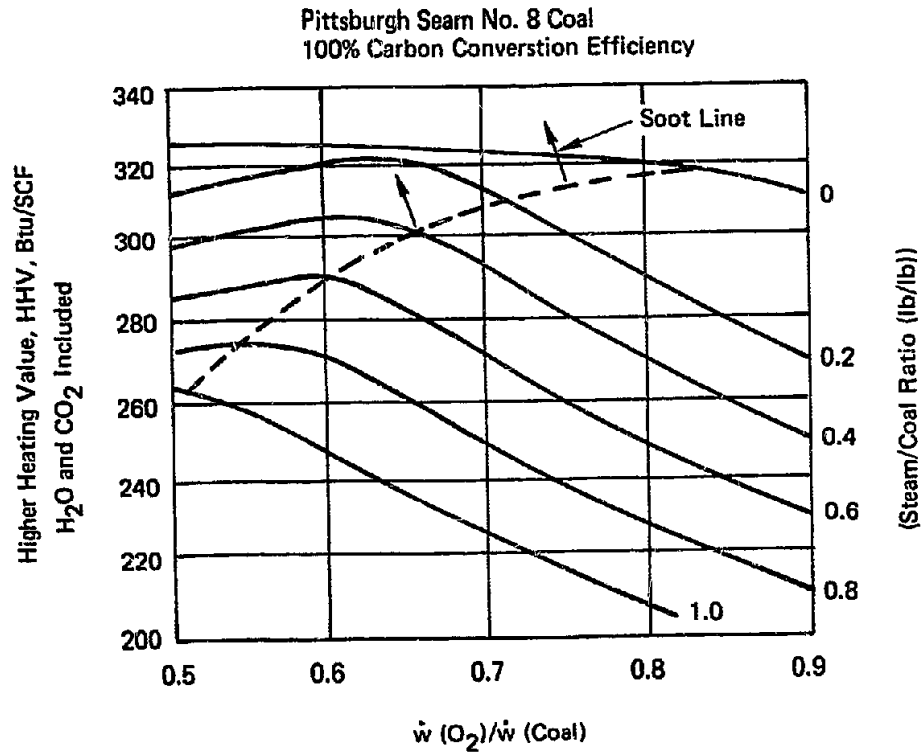


Figure 5.2-3 Effect of Oxygen/Coal and Steam/Coal Mixture Ratio Upon Gasifier Product Gas Higher Heating Value

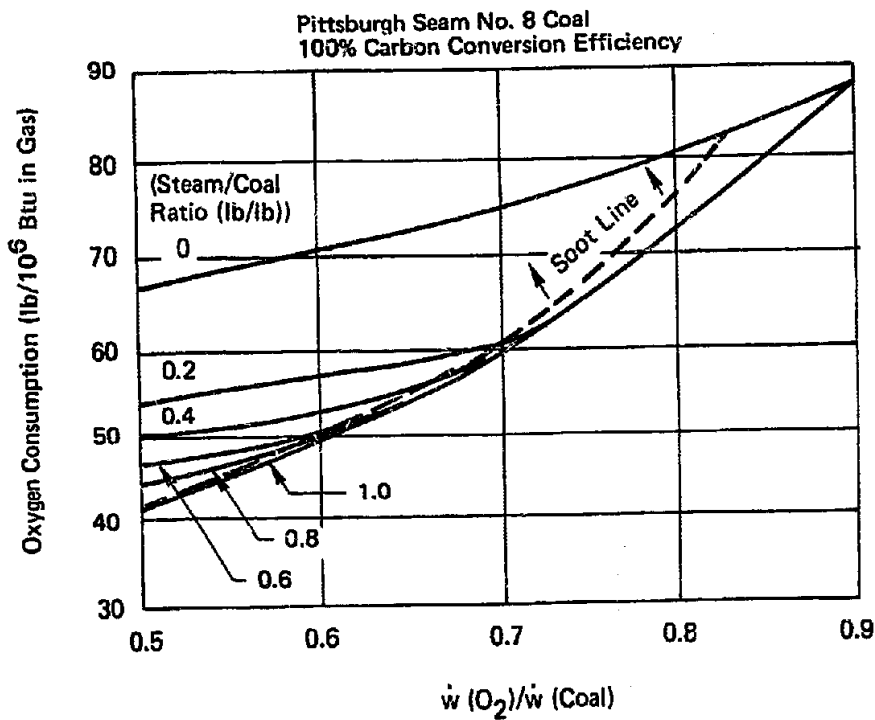


Figure 5.2-4 Effect of Oxygen/Coal and Steam/Coal Mixture Ratio Upon Gasifier Specific Oxygen Consumption

Thermodynamic Equilibrium Computations for Pittsburgh Seam No. 8 Coal
100% Carbon Conversion Efficiency

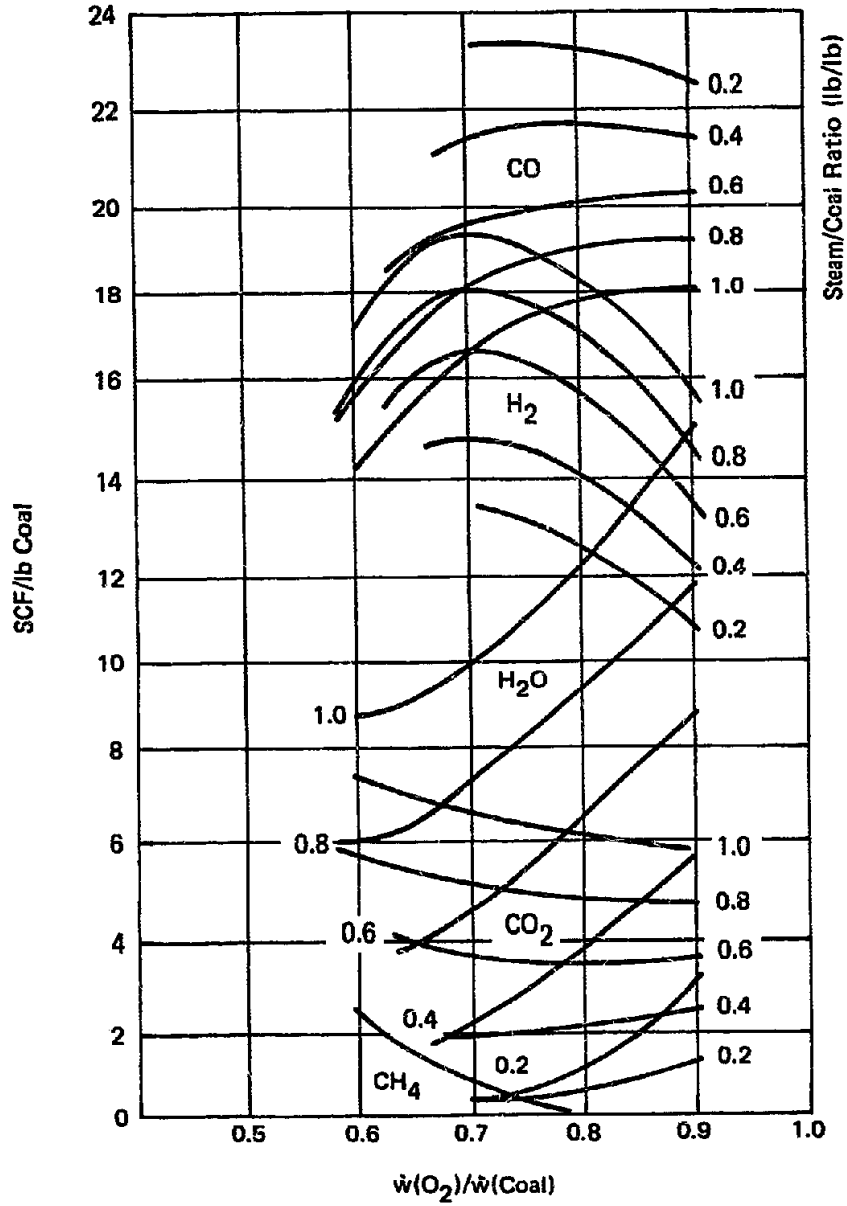


Figure 5.2-5 Effect of Oxygen/Coal and Steam/Coal Mixture Ratio Upon Gasifier Product Gas Species

5.2.2 Parametric Analysis for Gasifier with Secondary Coal Injection

The objective of this analysis was to determine the effects of secondary/primary coal ratio, secondary carbon conversion efficiency, steam/coal ratio, and char recycling on the performance parameters of an oxygen-blown High Mass Flux (HMF) gasifier with secondary coal injection, designed for production of substitute natural gas (SNG).

The products from Zone A/Zone B of the HMF gasifier can be processed further by shift conversion and methanation to produce a high-methane content SNG. However, a significant fraction of the energy potential of the coal (about 20 percent) is converted to heat in the methanation process, and the cold gas efficiency of the SNG process is correspondingly lowered.

It has long been recognized that a more efficient route to the production of SNG is the direct hydrogenation of the carbon in the coal to produce methane. However, this reaction requires: (1) a source of hydrogen, (2) high operating pressure, (3) long reaction time in comparison to the carbon-oxygen reaction, and (4) careful control of reaction temperature within the range that thermodynamically favors methane formation.

A practical compromise is to form part of the product methane in the gasifier and complete the process in the methanator. This approach is taken with SNG processes using the Lurgi gasifier, and with the Hy-Gas and Bi-Gas processes. Clearly, the more methane that can be formed and retained in the main gasifier product, the less supplemental methanation will be required, and the higher will be the overall process cold gas efficiency.¹ These considerations have led to the concept of injecting secondary coal into the hot Zone B product of the HMF gasifier, forming methane by the rapid pyrolysis of the coal and by hydrogenation of the active sites on the nascent char particles. The methane-rich product thus formed is rapidly quenched with water to 1000°F or below in order to stop any methane decomposition reactions that are thermodynamically favored at the higher Zone B temperature.

This analysis is not concerned with the problem of determining how much secondary coal can be injected and successfully methanated in the HMF gasifier as this will be determined by test. Rather, it considers the effect on overall plant performance of selected values of secondary coal injection and of secondary carbon conversion efficiency. The purpose is to determine how secondary coal injection performance affects overall process gains, in comparison with a process having no secondary coal injection.

¹Cold gas efficiency:

Higher heating value of clean SNG produced from one pound of coal feed (primary plus secondary) divided by higher heating value of one pound of coal feed.

5.2.2.1 Method of Analysis – The performance parameters used for this comparison are cold gas efficiency, specific oxygen consumption (in pounds per million Btu of product gas), net specific water consumption, and power output (the latter assuming that recoverable char and sensible heat in excess of the gasifier steam requirements could be converted to electric power at a heat rate of 10,000 Btu/kW hr.). Given the local site costs of coal, oxygen, water, and electric power, it would then be possible to calculate and compare the raw material operating costs of the various options. However, costs have not been included in this study.

The gasifier subsystem used as a basis for this study is shown schematically in Figure 5.2-6. It consists of a HMF gasifier operating at 500 psia, a slag quench tank, a hot gas heat exchanger, a cyclone-type char separator, a moisture condenser and knockout drum, a shift converter, a second moisture condenser and knockout drum, a low temperature Selexol-type acid gas removal unit, a methanator, and a product gas dryer. Heat recovered from the gasifier, the heat exchangers and condensers, the methanator, and char burners (if any) are used to heat boiler feedwater and generate steam. Part of the steam is consumed in the gasifier, the remainder goes to a condensing steam turbine where it generates electric power to provide for plant accessory power requirements. In most cases studies, the char recovered from the cyclone separator is burned with air to generate steam. However, in some cases the char is recycled to Zone A of the gasifier where it is substituted for part of the fresh coal. All water, except for that consumed in the gasifier and the shift converter, is condensed and collected in the settling pond, and is reused in the process together with makeup water. Carbon-dioxide is recovered from the Sulfur Recovery unit (downstream of the Selexol), and is used to fluidize and transport coal and char in the system. Oxygen is supplied to the gasifier from an air separation plant which derives its power from the gasification plant electric generator. The nitrogen from the air separation plant is not used.

A computer program was written to perform the heat and mass balance calculations for the gasification system. Utilizing this program, a total of 28 system calculations were made, encompassing the following variables:

1. Secondary/primary coal flow ratio - 0, 0.2, 0.4, 0.6, 0.8
2. Secondary carbon conversion efficiency - 10, 25, 50, 75, 90 percent
3. Steam/coal ratio - 0.2, 0.3, 0.4
4. Without char recycle - 20 cases
With char recycle - 8 cases

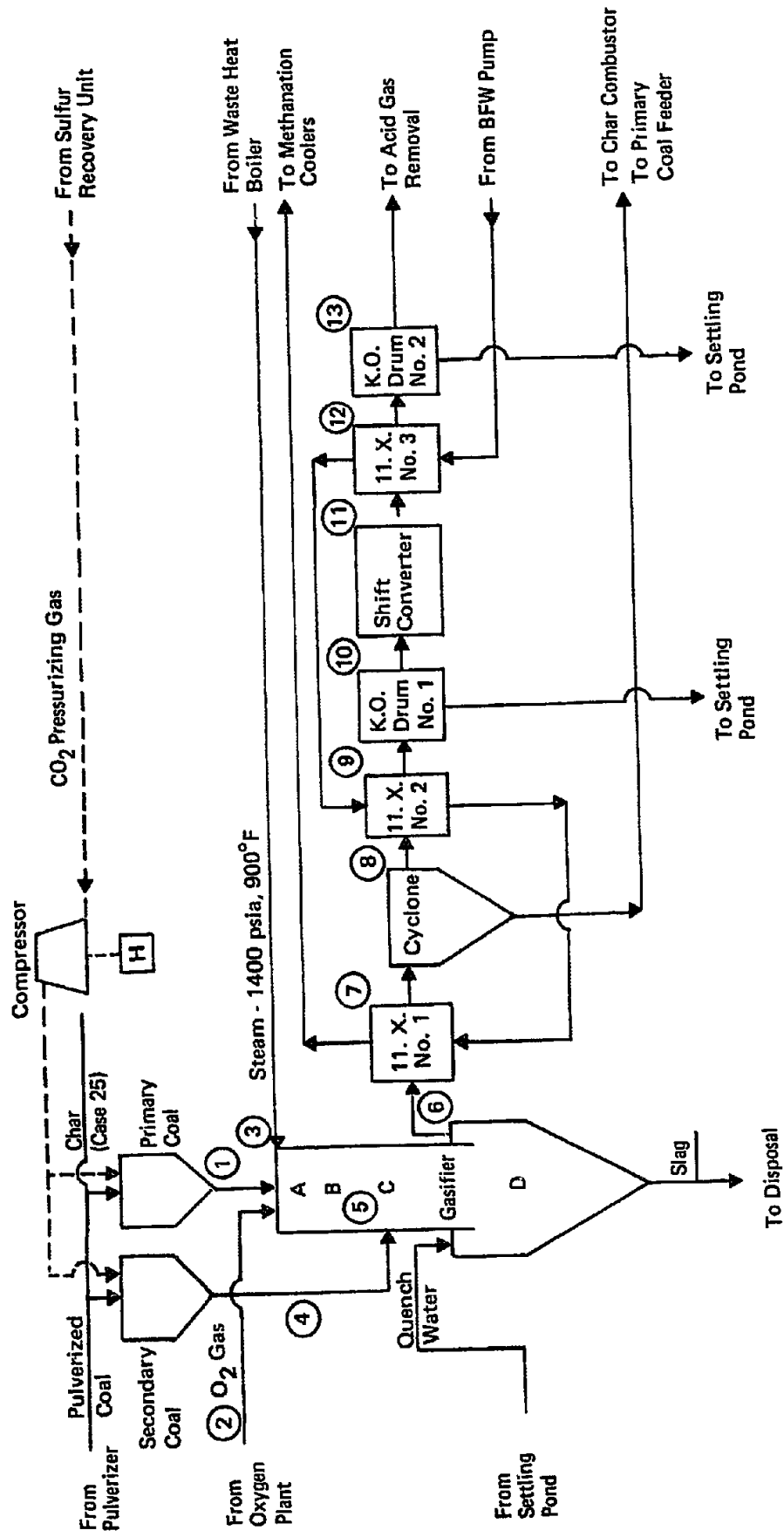


Figure 5.2-6 Flow Diagram for HMF Gasifier Subsystem in SNG Plant Application

Design conditions that were fixed during the calculations were:

1. Type of coal - Pittsburgh Seam No. 8 bituminous
2. Primary coal flow rate - 100 lb/sec
3. Primary oxygen/coal ratio (dry basis) - 0.70
4. Percent primary carbon gasified - 90
5. No coal or oxygen preheat
6. Steam conditions - 1450 psia/900°F
7. CO₂ pressurizing and fluidizing gas at 600 psia
8. Gasifier pressure 500 psia
9. No heat losses from reactor
10. Moisture content of coal as fed to gasifier - 2.0 percent
11. Quench temperature - 1000°F
12. Temperature to cyclone - 500°F
13. H₂/CO ratio for shift conversion - 3.03
14. Temperature to Selexol - 100°F
15. Percent CO₂ removed in Selexol - 98
16. In char recycle cases:
 - a. 98% of char from Zone C is recycle; 2% is lost.
 - b. Carbon in the char replaces an equal amount of carbon from fresh coal.
 - c. Char is recycled to the primary zone only.
 - d. (A convenience assumption), the carbon/slag ratio in the char is equal to the carbon/ash ratio in the fresh coal.

A "base" case was first calculated, with no secondary coal, no shift conversion, and no methanation (a typical medium Btu gas process). All other cases included both shift conversion and methanation, and produced a Substitute Natural Gas (SNG) containing no carbon monoxide and approximately 95 percent methane. A case was run with no secondary coal; hence all methane is produced in the methanator. Another case was run with no secondary coal but in which char extracted at the cyclone was recycled back to Zone A of the gasifier. The rest of the cases used various amounts of secondary coal and assumed a range of secondary carbon conversion efficiencies.

5.2.2.2 Discussion of Results – The primary question is whether, and under what circumstances, would injection of secondary coal lead to the more efficient production of SNG. If we limit ourselves to this question alone, then there are two principal input variables: (1) the secondary/primary coal ratio, and (2) the secondary carbon conversion efficiency. Likewise these are three principal performance criteria: (1) cold gas efficiency, (2) specific oxygen consumption, and (3) specific water consumption. The effects of input variables upon performance criteria are discussed in the following.

5.2.2.2.1 Cold Gas Efficiency – Figure 5.2-7 shows how cold gas efficiency (which is proportional to the reciprocal of specific coal consumption¹) varies with the secondary carbon conversion efficiency, for various ratios of secondary/primary coal. Without char recycle, it is interesting to observe that all of the lines cross at a single point where carbon conversion efficiency is 53.4 percent

¹Specific coal consumption:

Pounds of coal (primary plus secondary) required to produce one million BTU of clean product SNG: i.e., xlbc/10⁶ BTU SNG.

$$\text{Thus: } \frac{10^6 \left(\frac{\text{BTU SNG}}{\text{lbc}} \right)}{x} \propto \frac{10^6 \left(\frac{\text{BTU SNG}}{\text{lbc}} \right)}{x} \times \frac{1}{\text{HHV}_c} = \text{Cold Gas Efficiency}^2$$

²Reference definition on page 16.

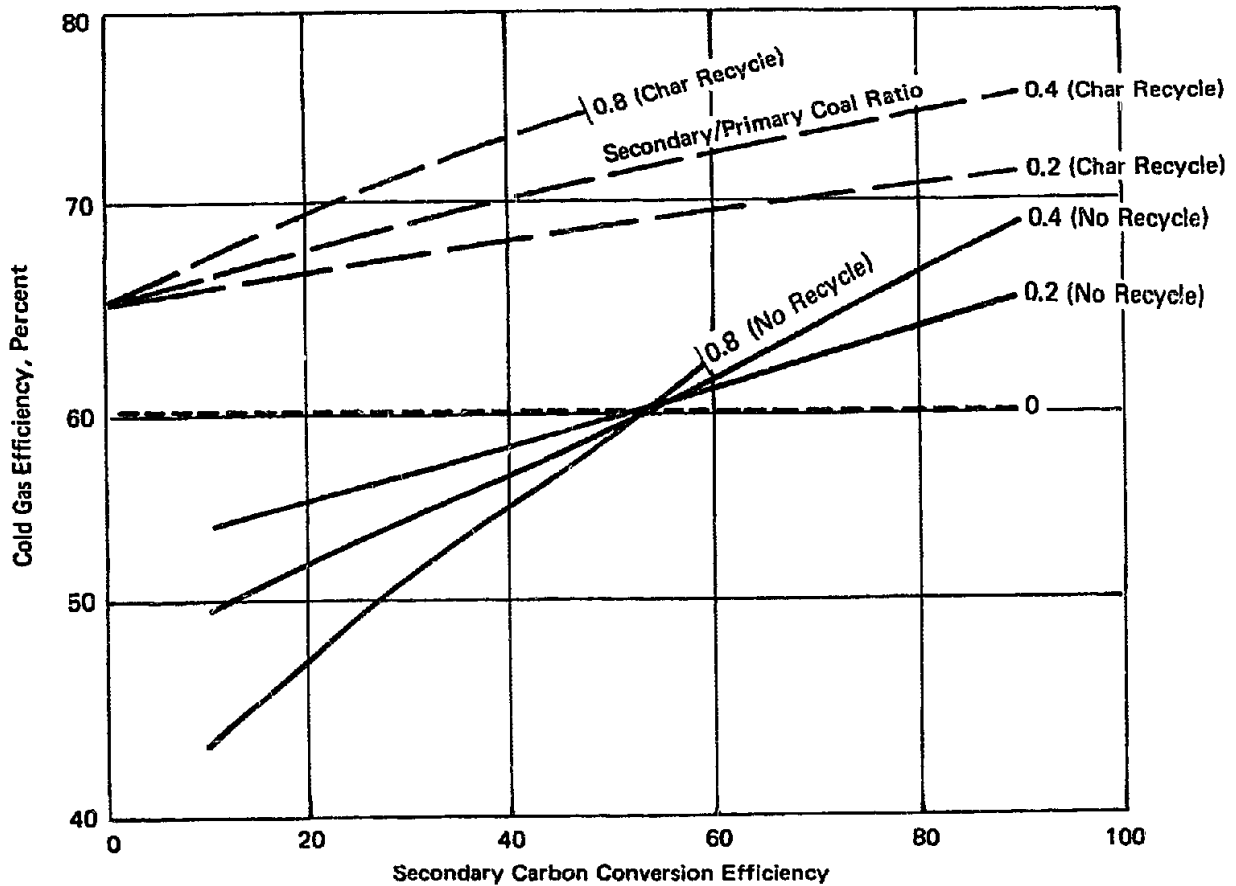


Figure 5.2-7 Cold Gas Efficiency versus Secondary Carbon Conversion Efficiency

and cold gas efficiency is 60.25 percent. At lower values of carbon conversion efficiency, the cold gas efficiency decreases with increasing secondary/primary coal ratio; at higher values it increases. The location of this intersection will change slightly with changes in primary O_2 /coal ratio and/or primary carbon conversion efficiency; it is unaffected by H_2O /coal ratio. With char recycle and a resulting overall carbon conversion efficiency approaching 100%, the common intersection shifts to a point where secondary carbon conversion efficiency is zero and cold gas efficiency is 65.5 percent. Any increase of either secondary/primary coal ratio or secondary carbon conversion efficiency result in an increase in cold gas efficiency.

The secondary/primary coal ratio cannot be increased indefinitely, as there is a limit to the amount of hydrogen available in Zone C for the hydrogasification of carbon. In the present study, the hydrogen-limited secondary carbon conversion efficiency was 57.8% at a secondary/primary coal ratio of 0.8, and 68.2% at a secondary/primary ratio of 0.6. With char recycle, the hydrogen-limited efficiency decreased to 47.7% at a secondary/primary ratio of 0.8. These numbers only indicate trends, since they do not allow for additional hydrogen formed by water/gas shift reactions in Zone C. Increasing the primary H_2O /coal ratio increases hydrogen production and, in a typical sample case, doubling H_2O /coal ratio from 0.2 to 0.4 increased the hydrogen-limited carbon gasified from 58.2% to 73.5%.

5.2.2.2.2 Specific Oxygen Consumption – Figure 5.2-8 indicates how specific oxygen consumption varies with the secondary carbon conversion efficiency, for various ratios of secondary/primary coal.

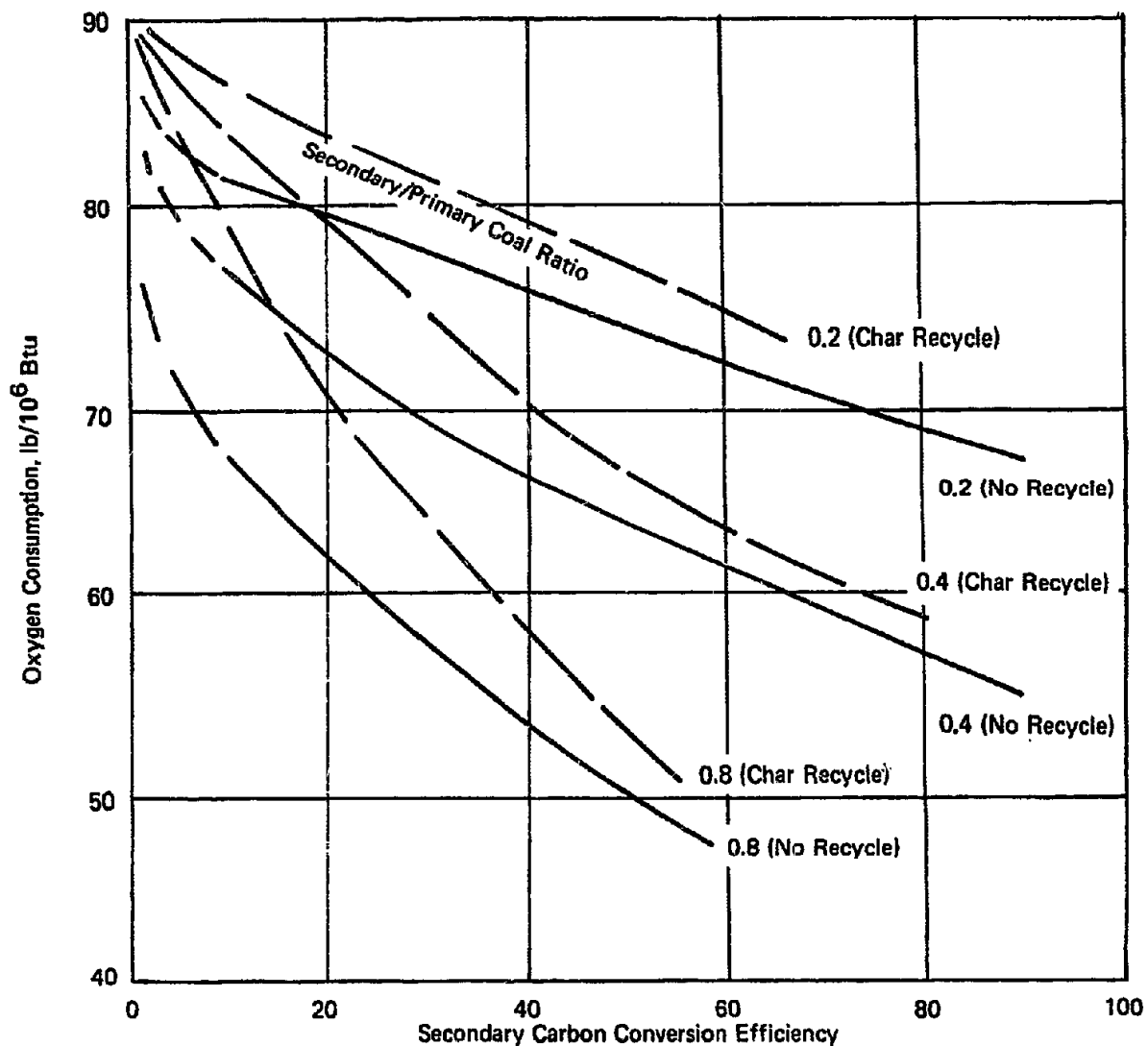


Figure 5.2-8. Oxygen Consumption versus Secondary Carbon Conversion Efficiency After Methanation

Specific oxygen consumption decreases with increasing secondary coal, even at very low conversion efficiencies, and decreases further as secondary carbon conversion efficiency increases. This is an important characteristic, since the cost of oxygen rivals the cost of coal as a major factor influencing plant operating cost. Recycling of the char increases oxygen consumption in comparison with the no-recycle cases, but the difference between the two decreases as carbon conversion efficiency increases.

5.2.2.2.3 Process Water Consumption – Figure 5.2-9 shows net process water consumption versus secondary/primary coal ratio for various values of secondary carbon conversion efficiency. The calculations assume that any water added to the process but not consumed can be recovered and recycled. (Note the change in presentation.) The curves indicate that at a secondary carbon conversion efficiency slightly above 50 percent the specific water consumption will be independent of secondary/primary coal ratio. At higher values of carbon conversion efficiency, the specific water consumption increases with secondary/primary coal ratio; at lower values it decreases. Recycling of char brings all of the water consumption curves close together; they show a small increase of water consumption with either secondary/primary coal ratio or secondary carbon conversion efficiency.

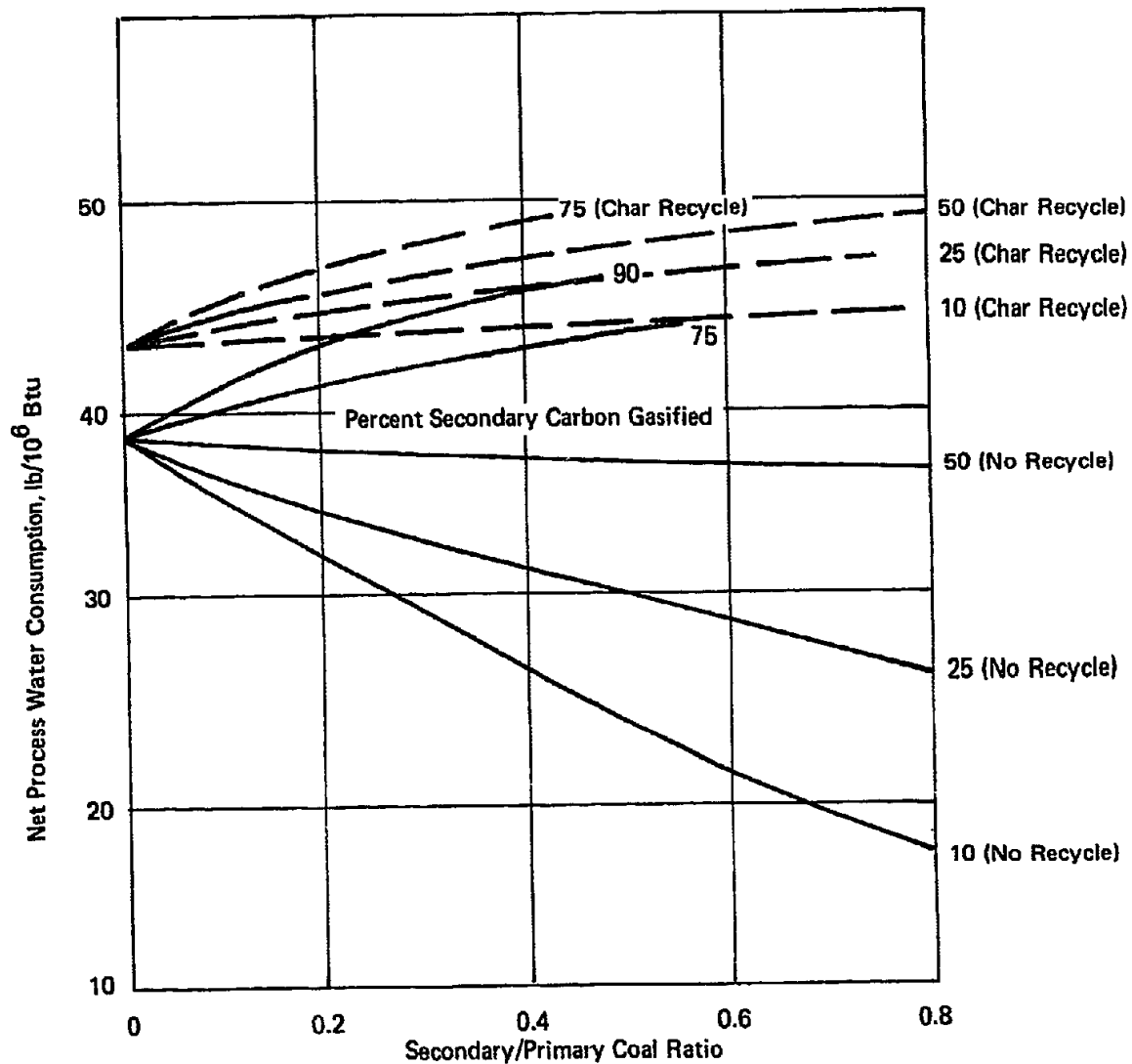


Figure 5.2-9. Net Process Water Consumption versus Secondary/Primary Coal Ratio after Methanation

5.2.2.2.4 Specific Coal plus Oxygen Consumption – Since the unit costs of coal and oxygen are roughly the same, and since both are major cost drivers, an indication of their combined effect upon the cost of product gas for various operating conditions can be obtained by comparing the sum of the coal plus oxygen consumption under these conditions. A plot of weight of coal plus oxygen/ 10^6 Btu versus percent secondary carbon gasified, with secondary/primary coal ratio as a parameter, with and without char recycle, is shown in Figure 5.2-10.

Without char recycle, the parametric curves all intersect at a secondary carbon conversion efficiency of approximately 24 percent, at which value the coal plus oxygen consumption is equal to 214 lb per million Btu, or the same as for a gasifier without secondary coal injection. At higher conversion efficiencies, the coal plus oxygen consumption is lower and decreases with increased secondary/primary coal ratio. The minimum coal plus oxygen consumption is approximately 165 lb/ 10^6 Btu, and is limited by the availability of hydrogen to Zone C of the gasifier. With char recycle, the point of intersection shifts to zero, and any increase in either secondary/primary coal ratio or secondary carbon conversion decreases the coal plus oxygen consumption. The hydrogen-limited minimum value is approximately 156 lb/ 10^6 Btu.

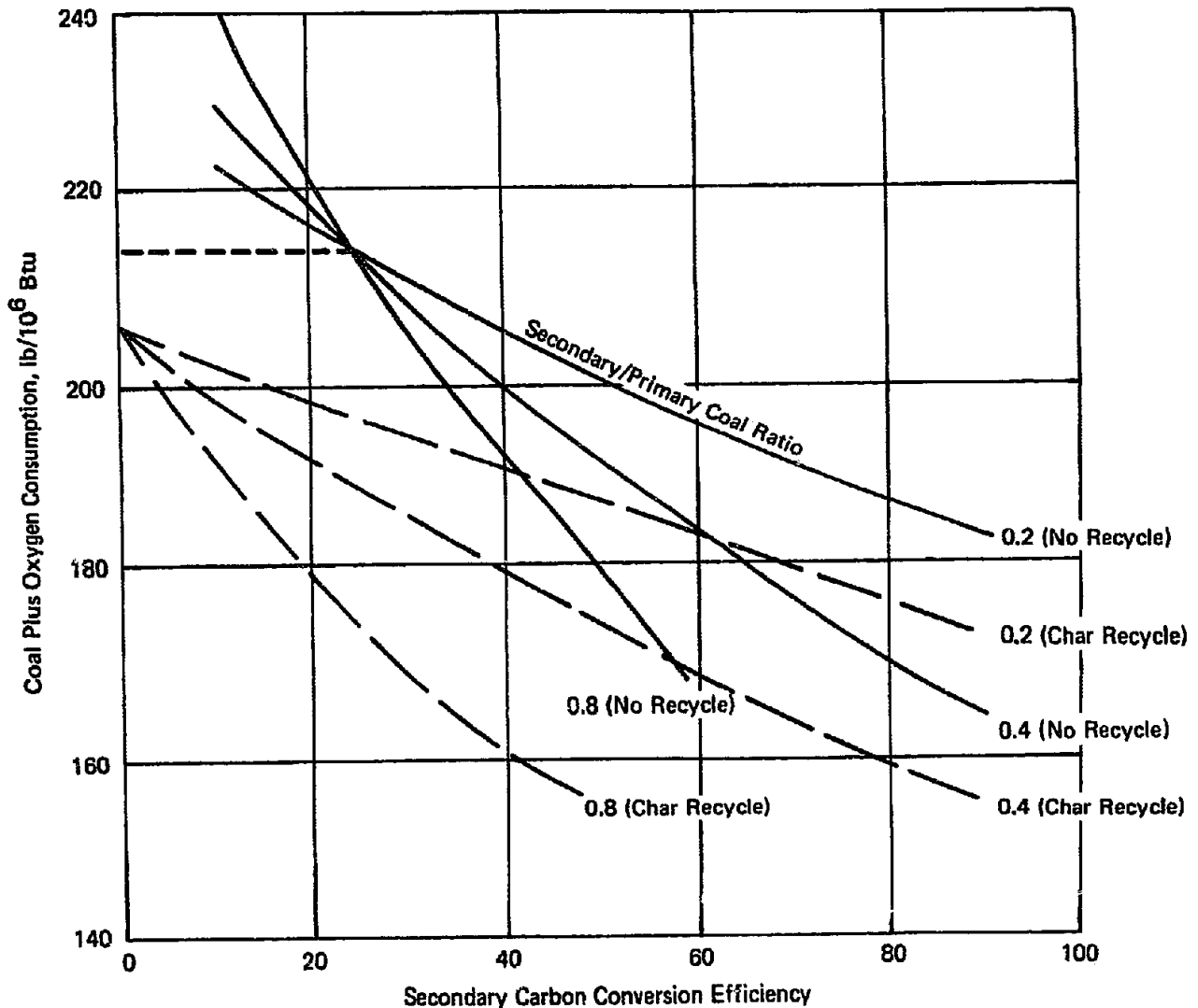


Figure 5.2-10. Coal Plus Oxygen Consumption versus Secondary Carbon Conversion Efficiency after Methanation

5.2.2.2.5 Zone C Exit Temperature – The temperature of the product gas leaving Zone C of the gasifier is very sensitive to both secondary/primary coal ratio and secondary carbon conversion efficiency, as indicated in Figure 5.2-11.

If the temperature entering Zone C is controlled at 2500°F, the temperature leaving Zone C can vary over a wide range, from below 2000°F for high secondary/primary ratios and low conversion efficiencies to approximately 2800°F at high conversion efficiencies. This sensitivity is due to the competing effect of two reactions; pyrolysis (an endothermic process) and hydrogasification (an exothermic process). Char recycling has a relatively small effect on the Zone C exit temperature. The lines of constant secondary/primary ratio appear to converge at a conversion efficiency of 55-58 percent, and in this range the temperatures from Zone C and Zone B are approximately equal. The temperature effect may set a practical limit on the operability of secondary coal injection, as temperatures much below the selected Zone B temperature may result in a viscous slag which may be difficult to move through the gasifier without the addition of fluxing agents.

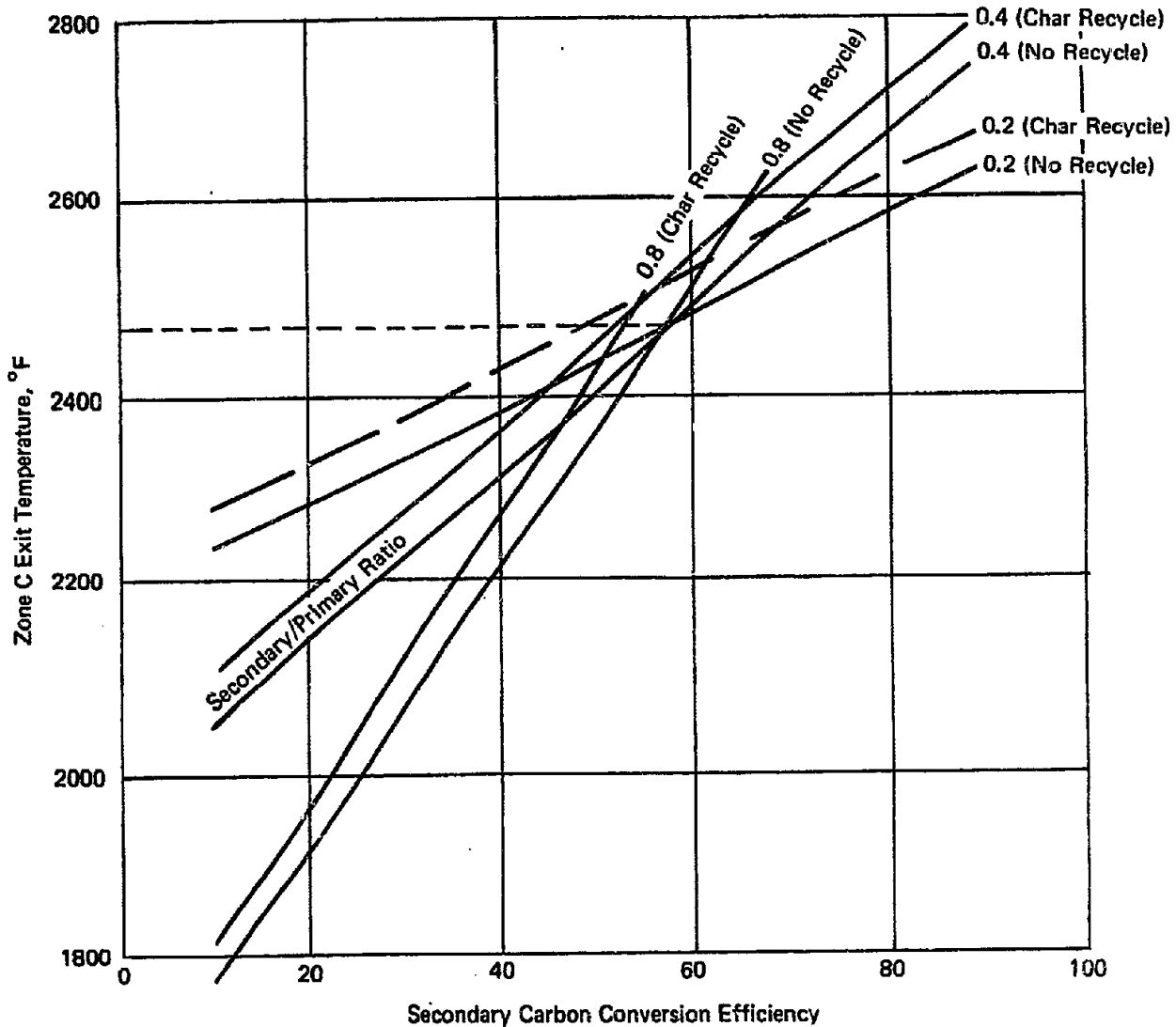


Figure 5.2-11. Zone C Exit Temperature versus Secondary Carbon Conversion Efficiency With and Without Char Recycle in Zone B

5.2.2.3 Summary of Results – Without char recycling, a minimum secondary carbon conversion of 53 percent should be attained in order to justify secondary coal injection on the basis of cold gas efficiency alone. However, when oxygen consumption is given equal consideration, the break-even value decreases to 24 percent. At higher carbon conversion efficiencies, the net coal plus oxygen consumption is lower than for the case of no secondary injection, and it continues to decrease with increasing secondary/primary coal ratio until the “hydrogen depletion” limit is reached. With char recycle, secondary coal injection appears to pay off in reduced coal and oxygen consumption even at low secondary conversion efficiencies: the benefits increasing as conversion efficiency increases. The temperature leaving the secondary gasification Zone and slag handling considerations may set a practical lower limit on conversion efficiency.

There is a significant potential incentive for the use of secondary coal injection. Comparison of performance predictions for char recycle cases with (a) no secondary coal injection and (b) a secondary coal feed rate of 33% of total, and secondary carbon conversion efficiency of 75% indicate the following:

	Overall Performance Coal to SNG	
	No Secondary Coal (Case (a))	Secondary Coal (Case (b))
Product SNG (SCF/lb coal)	9.21	10.23
Cold Gas Efficiency (%)	65.28	73.95
Specific O ₂ Consumption (lb/10 ⁶ Btu)	90.13	59.61
Specific O ₂ plus Coal Consumption (lb/10 ⁶ Btu)	206.27	162.13

Assuming equal cost for coal and oxygen, the cost of these materials for the case where secondary coal injection is used is some 21% less than for the case with no secondary coal.

5.2.3 Gas Options for Coal Transportation and Injection

In the HMF gasifier, a supply of carrier gas is needed to convey the pulverized coal and/or char into the gasifier. Pressurizing gas is required to pressurize the contents of the coal feed hopper to a level above the gasifier pressure. Accelerating gas is mixed with the pulverized coal just ahead of the injection point to increase the momentum of the stream and improve its mixing with the oxidizer and steam within the gasifier.

Gasification tests at Bell, up to this time, have used nitrogen as the pressurizing gas and compressed air as the accelerating gas. These gases were selected as a convenience in testing, as both were readily available in the test facility. Nitrogen is an inert gas, essentially non-reactive with the coal and other fluids in the gasification process. Air was selected originally as an accelerating gas for the air-blown reactor tests, as large quantities were being fed to the gasifier, and it was a simple matter to divert a portion of the gasifier air supply. For convenience during the (company sponsored) oxygen-blown tests, use of air for acceleration was continued even though it was no longer one of the primary process reactants.

It is recognized that nitrogen and air are not optimum choices for a complete SNG process, and that a changeover to the more optimum gases should be made early in the gasifier development program. Identification of "optimum" gases was the purpose of this study.

5.2.3.1 Selection Criteria – The selection criteria for pressurizing and accelerating gases was defined as follows:

1. The gas should be readily available from within the process or from the immediate environment at minimum cost.
2. Use of the gas should not reduce plant output or efficiency, nor increase oxygen, water, or power consumption.
3. The gas should not adversely affect product gas quality.
4. The gas should not reduce reactivity in the gasifier, nor suppress required gasification, shift conversion, or methanation reactions.

5. Use of the gas should not increase plant or environmental hazards of explosion, fire, or toxicity.
6. The gas should not condense in the pulverized coal.

From the standpoint of the tests to be run on the current contract, two more criteria are needed:

7. The gas should not increase the difficulty of data reduction, with respect to identification of product species, mass and energy balance.
8. The gas should not bias or compromise test objectives; for example, methane should not be added to Zone C as it would interfere with the objective of methane formation in Zone C.

5.2.3.2 Candidate Gases – The following candidate gases were considered in this study:

1. Nitrogen - available at 1 atm. pressure as a by-product from the oxygen plant.
2. Air - available at 1 atm. from environment, and at 90 psig from the oxygen plant air compressors.
3. Oxygen - available at gasifier feed system pressure from the oxygen plant oxygen compressor.
4. Steam - generated within the plant at high pressure from gasifier sensible heat and char combustion.
5. Carbon dioxide - available at 1 atm. pressure from the output of the sulfur recovery unit.
6. Methane - available from SNG plant output at near gasifier pressure.
7. Synthesis gas (SG) - the product gas as it exits from the Acid Gas Removal Unit, before methanation. Available at near gasifier pressure. There are three possible compositions for this gas, as follows:

SG-1: The product gas from a gasifier without secondary coal injection and without shift conversion. Approximate composition (mole percent): CO-62%, H₂-37%, inerts-1%. Molecular weight - 18.3, HHV-6600 Btu/lb.

SG-2: The product gas from a gasifier without secondary coal injection but with shift conversion. Approximate composition, mole percent: H₂-73.5%, CO-24.5%, inerts-2%. Molecular weight - 9.06, HHV-13260 Btu/lb.

SG-3: The product gas from a gasifier having both secondary coal injection and shift conversion. The approximate composition (assuming 75% carbon conversion efficiency on Zone C) is: H₂-57%, CO-19%, CH₄-22%, inert-2%. Molecular weight - 10.7, HHV-16480 Btu/lb.

For the commercial application some of these gases can be eliminated from further consideration at the outset. Nitrogen and air are unsuitable in an SNG gasification system, because the

nitrogen dilutes the product gas and cannot be removed except by an expensive cryogenic separation process.

Oxygen should probably also be eliminated from the list because of fire and explosion hazards associated with its reactivity with pulverized coal.

The remaining candidates are therefore steam, carbon dioxide, methane and syngas.

5.2.3.3 Performance Comparison – The performance of a typical gasifier - SNG system was calculated in order to determine the effect of the various candidate gases on performance parameters such as cold gas efficiency, specific O₂ and steam consumption, and higher heating value. Assumptions common to all cases were:

1. Coal - Pittsburgh Seam No. 8 Bituminous
2. Adiabatic gasifier temperature, Zone B - 2500°F (O₂/coal and steam/coal ratios were adjusted for the different gases to give the same temperature).
3. Carbon conversion efficiency, Zone B - 90%
4. Quench temperature - 1000°F
5. Shift converted to H₂/CO ratio of 3.0
6. All H₂S and 98% of CO₂ removed (in Selexol unit) at 100°F
7. Methanated and dried to dewpoint of 77°F

Variables considered in the calculations were:

1. Candidate gases - N₂, air, steam, CO₂, CH₄, SG-2 and SG-3
2. Coal feed pressures - 260 and 600 psia
3. Secondary/primary coal ratio - 0 and 0.4

A base case was calculated in which the pressurizing gas was nitrogen and the accelerating gas was air. The calculations were then repeated, substituting each of the candidate gases and adjusting the O₂/coal and steam/coal ratios as necessary to maintain the reaction temperature at 2500°F. The comparisons are straightforward except for those cases in which the candidate gas is drawn from the main product stream and recirculated. In those cases, both a gross and net performance were computed.

The results of these calculations show that the performance criteria (cold gas efficiency, specific oxygen and steam consumption, and higher heating value) are not very sensitive to the properties of the candidate gases. Among the candidate gases, only methane shows a loss of 7% of cold gas efficiency compared to the base case; all others are within ±1% of the mean value of 60.5%. It was also shown that efficiency drops slightly as pressure is increased, and that specific oxygen consumption (pounds per million Btu) is much less affected by gas properties than it is by the oxygen/coal ratio. The conclusion reached from this part of the study was that performance criteria will not have a major influence on the selection of the optimum gas except in the case of the methane option.

5.2.3.4 Reaction Considerations – The presence of a carrier gas along with the coal may be expected to have some influence on the reactions occurring within the reaction Zones A, B and C. In Zone A, the principal reaction sought is the oxygen-carbon reaction, a highly exothermic reaction producing mainly CO. However, if hydrogen or a hydrocarbon gas is present, it will react preferentially

with the oxygen, leaving less O_2 to react with the carbon. The source of such reactive gases may be pyrolysis products from the coal, or one of the fuel-rich carrier gases such as CH_4 or syngas. It is debatable whether or not such gas phase reactions in Zone A are helpful to the overall carbon conversion. From one point of view, these reactions force more of the carbon to be gasified in Zone B via the endothermic reduction of CO_2 and H_2O , which reactions are known to be much slower than the $C + O_2$ reaction. However, it can also be argued that the gas phase reactions in Zone A produce more heat, more rapid pyrolysis, and more active sites on the char particles, thus accelerating the gasification reaction.

If the carrier gas is CO_2 or H_2O , the reactions with coal are endothermic reduction reactions. In Zone A, the probable effect is to dilute the oxidation reaction and lower the temperature. In Zone B the reaction rates should be little affected. The product gas composition in Zone B will be affected by the composition of the carrier gas as it influences the water gas shift equilibrium. The addition of steam will tend to increase the mole fraction of hydrogen in the product gas, while addition of CO_2 will tend to lower hydrogen and increase CO.

In Zone C, it is desirable to have as high a concentration of hydrogen as possible in order to favor the formation of methane. Hence steam or syngas would be preferable to CO_2 as a carrier gas. Methane would be undesirable as a carrier gas in Zone C, as its presence would probably tend to suppress methane formation.

5.2.3.5 Potential Hazards

1. Nitrogen - none
2. Carbon dioxide - none
3. Air - none. It has been used as an accelerating gas with pulverized lignite, Montana Rosebud sub-bituminous, and Pittsburgh Seam No. 8 bituminous coals without incident.
4. Methane - a possible fire hazard during venting. Vent gases should be piped to the burn-off stack for disposal or else recompressed and reused.
5. Syngas - a possible fire and toxic (CO) hazard during venting. Vent gases should be piped to the burn-off stack for disposal, or else recompressed and reused.
6. Steam - none specifically associated with its use as an accelerating gas.
7. Oxygen - regarded as a fire and explosion hazard when in contact with pulverized coal. Use as a carrier gas is not recommended. Use as an accelerating gas is a possibility.

5.2.3.6 Condensation – Of the candidate gas under consideration, all except CO_2 and H_2O are “permanent” gases with normal boiling points below $250^\circ F$. Consequently, they may be treated as perfect gases when used for coal transportation. Steam and carbon dioxide, however, have liquid and solid phases in the temperature and pressure ranges of concern. In the case of steam, it is highly unlikely that it would be practical as a pressurizing gas since, even if it were highly superheated when fed into the lock hopper, it would quickly cool below its condensation point. As an accelerating gas this restriction no longer applies, and superheated steam can be mixed with a flowing stream of pulverized coal as long as the mixed stream temperature does not fall significantly below the dew point.

The same restrictions also apply to CO_2 , except that in some cases (if the pressure is low enough and the temperature high enough) CO_2 can be used as a pressurizing gas without condensation. Even under these conditions, CO_2 near its saturated vapor condition is not a perfect gas, and more gas is required for pressurization than would be calculated from the perfect gas law.

5.2.3.7 System Considerations – Apart from the matter of relative performance, the principal questions to be addressed with respect to selection of a carrier gas are: (a) source of the gas, (b) power required to compress gas to feed system pressure, (c) effect on overall throughput of gasifier and downstream components, and (d) system losses and/or steps necessary to avoid losses.

Carbon dioxide and nitrogen are waste byproducts of the system that would normally be discarded. They are available at approximately one atmosphere pressure, and will require a compressor (multistage, intercooled) to be compressed to feed system pressure. In a lock-hopper feed system, these gases can be vented to atmosphere without further economic penalty.

Syngas and methane are mainstream products of the process, and if they are to be recycled as carrier gases steps should be taken to minimize waste. Since they are extracted from the process stream at near gasifier pressure, much less power is required to compress them to feed system pressure than is the case with CO_2 or N_2 . On the other hand, lock-hopper vent gases should not be discarded, but should be recompressed and reused or returned to the main stream, preferably just upstream of the Selexol unit. It should also be noted that if recycled product methane is used as the carrier gas, the portion of methane that enters the gasifier with the primary coal will, in the main, probably be reformed into CO and H_2 ; this represents both a thermal and an economic loss to the process. This is also true to a lesser degree with syngas SG-3, which contains some methane formed in Zone C of the reactor.

Steam is acceptable as an accelerating gas for Zone A. It is readily available in the process at high pressure. However, it is desirable for reasons of process efficiency to limit the amount of steam fed to the gasifier to a steam coal/ratio of about 0.20. Accelerating gas requirements for primary coal at 260 psia would use about half of this steam. At 750 psia a steam/coal ratio for acceleration would be about 0.30. Mixtures of steam and oxygen would be an approach to maintaining low steam flows and further study of this approach is warranted. Steam is not suitable for the acceleration of secondary coal as the addition of H_2O will tend to suppress the CH_2 reaction.

5.2.3.8 Considerations for Current Test Program – In the series of tests to be run during the current program, it will not be possible to recover and recirculate the gases for coal pressurization or acceleration. Consequently, the selected gas(es) will have to be supplied from an external source. It is desirable, of course, to simulate to the extent practicable the conditions that would exist in a complete gasification system. Thus, for example, if CO_2 were to be used, it should be supplied at the temperature that would be developed in a typical compressor (approximately 300°F with intercooling).

The test system to be used on the contract does not include a shift converter; consequently the final gas product will be a syngas of high CO content such as SG-1. However, the product leaving the Selexol output of a complete SNG gasification system would be shifted to an H_2/CO ratio of 3, like syngas SG-2 or SG-3. Since the object of the test program is to simulate conditions in the gasifier rather than downstream, it would be proper to use SG-2 instead of SG-1. Addition of a mixed gas such as syngas to the gasifier input requires that the molar composition and the HHV of the syngas be known accurately. The test results measured on the gasifier will correspond to gross rather than net values; however, it is a simple matter to correct to net values by subtracting the carrier gas input from the total gas output. If CO_2 or another inert gas is used, this correction is not

required, because in the complete gasifier system, the CO₂ is not taken from the main gas stream for recirculation, but from the sulfur recovery unit output.

Use of nitrogen as a carrier gas for the test program is a practical approach, as it is not difficult to correct measured performance to a calculated performance by subtracting the carrier gas. However, since a mass spectrometer will be used to analyze the output gas and N₂ and CO have similar mass numbers, analysis of fragmentation peaks will be necessary to differentiate between these gas species.

5.2.3.9 Summary of Results

1. Carbon dioxide appears to be first choice as a pressurizing gas.

Its advantages are:

- a. Lowest cost - it is available as a waste byproduct of the process.
- b. Excess gas from lock-hopper cycling can be discarded without penalty.
- c. Safe, non-toxic, non-reactive.
- d. Can readily be separated from the product gas.

Its shortcomings are:

- a. Tendency to condense in the lock-hopper; requires preheating.
- b. Must be compressed from 1.0 atm. to coal feed system pressure.
- c. Will slightly reduce hydrogen content of Zone B output.

2. Synthesis gas (SG-2) is preferred as the accelerating gas.

Its advantages are:

- a. Low molecular weight; minimum mass required.
- b. Requires only small pressure boost.
- c. High hydrogen content; favorable to ignition and Zone C reaction.

Its shortcomings are:

- a. Relatively expensive, it cannot be discarded without reducing plant efficiency and increasing product cost.
- b. Flammable and toxic gases.

5.2.3.10 Recommendation for Commercial Process

1. Use CO₂ as the pressurizing gas for the pulverized coal feed tanks. Preheat the CO₂ to approximately 300°F in order to avoid condensation in the tanks.
2. The accelerating gas choice requires additional studies, especially with respect to overall plant efficiency and economics before a firm recommendation can be made. At this time, however, the use of SG-2 as accelerating gas for injection into Zone A and Zone C looks attractive.

5.2.3.11 Selection for Current Contract Test Program

1. Use N₂ as pressurizing gas for both primary and secondary coal feed tanks.
2. Use air as accelerating gas for primary coal.
3. Use a synthetic gas mixture of three parts H₂ to one part CO as accelerating gas for secondary coal.

5.3 GASIFIER DESIGN

5.3.1 Gasifier Sizing

The initial step in designing the HMF gasifier, to be used during the current program, was to establish superficial residence time requirements for each of the three reaction zones.

For Zone A, in which coal is devolatilized and oxidized, a nominal residence time of 20 milliseconds (ms) was selected. This requirement was based upon experience gained during air-blown testing of the HMF gasifier, when it was established that by the first gas sample station (approx. 40 ms residence time) all free oxygen was depleted, and on the fact that the oxygen partial pressure and Zone A reaction temperatures would be higher in the oxygen-blown mode of operation.

Residence time selected for Zone B, in which the principal reactions are: $C + H_2O \rightarrow CO + H_2$, $CO + H_2O \rightarrow CO_2 + H_2$, and $C + CO_2 \rightarrow 2CO$, was 200 ms. The time selected was based upon test results obtained during a company sponsored oxygen-blown gasification test program and steam/char and CO₂/char reaction rates reported in the literature.

The residence time selected for Zone C, in which secondary coal is reacted, was 280 ms. The selected time was based upon aromatic decomposition rates for benzene, the most stable aromatic, at approximately 2050°F.

Selected residence times were translated into reactor zone volumes, for a gasifier processing 0.5 ton of coal per hour and operating at fifteen atmospheres pressure. Results are present in Figure 5.3-1.

5.3.2 Gasifier Configuration

The HMF gasifier configured to satisfy the sizing requirements identified in Figure 5.3-1 is shown in outline in Figure 5.3-2.

Zone A consists of the reactor head section, into which primary coal and oxygen are injected, and a seven inch long cylindrical section. The reactor head and cylindrical sections both employ water-cooled steel liners to accommodate the high ($\approx 3200^{\circ}\text{F}$) Zone A reaction temperatures.

Zone	Reactants	Residence Time (ms)	Volume (ft ³)
A	Coal/Oxygen	20	0.1
B	Zone A Products/ Steam	200	0.9
C	Zone B Products/ Secondary Coal	280	1.4

Figure 5.3-1 Reactor Zone Residence Time and Volume

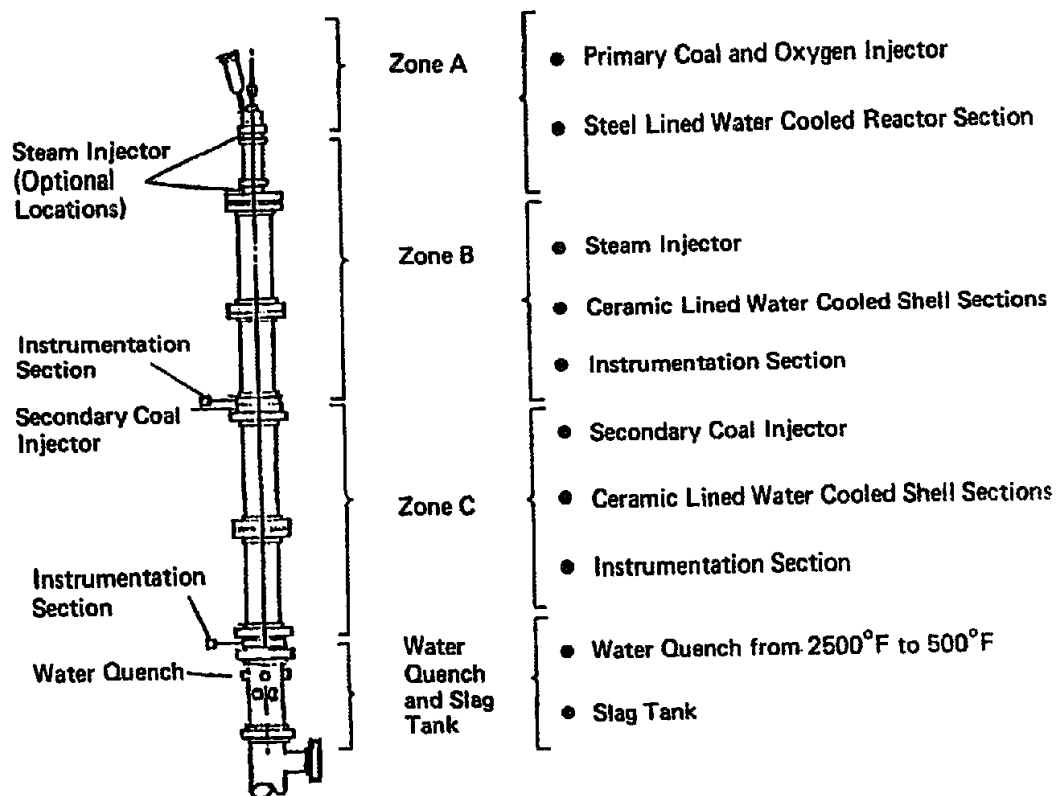


Figure 5.3-2. High Mass Flux Gasifier Configuration

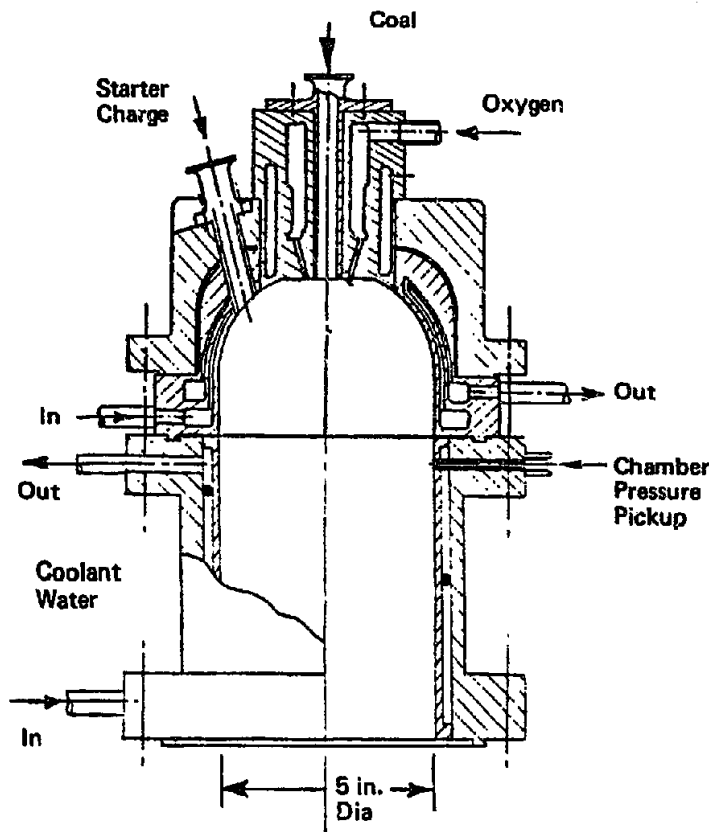
A radial steam injector defines the entrance to Zone B which is approximately six and a half feet long and has an internal diameter of five inches. Zone B is comprised of a short transition section and two three foot long cylindrical sections. The cylindrical sections have water-cooled outer steel shells and five inch internal diameter alumina chrome ceramic liners. An instrumentation ring is located at the outlet from Zone B. A water-cooled gas sample probe and gas temperature thermocouples are mounted in the instrumentation ring.

A secondary coal injector defines the entrance to Zone C. This zone has two three foot long cylindrical sections identical to those of Zone B except that the internal diameter is six inches.

An instrumentation ring, located at the exit from Zone C, is followed by a three foot long water quench section in which reaction products are cooled from approximately 2500° F to 500° F.

5.3.3 Reactor Design

The reactor was designed in modular form to facilitate configuration changes and component modification and repair. Reactor component designs are presented in Figures 5.3-3 through 5.3-9.



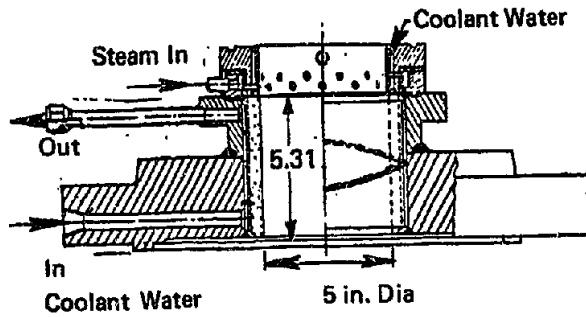
Injector

- Two-Pass Water Cooled Stainless Steel Head Liner
- Solid Propellant Grain Start System
- Concentric Oxygen and Coal Injectors

Cylindrical Section

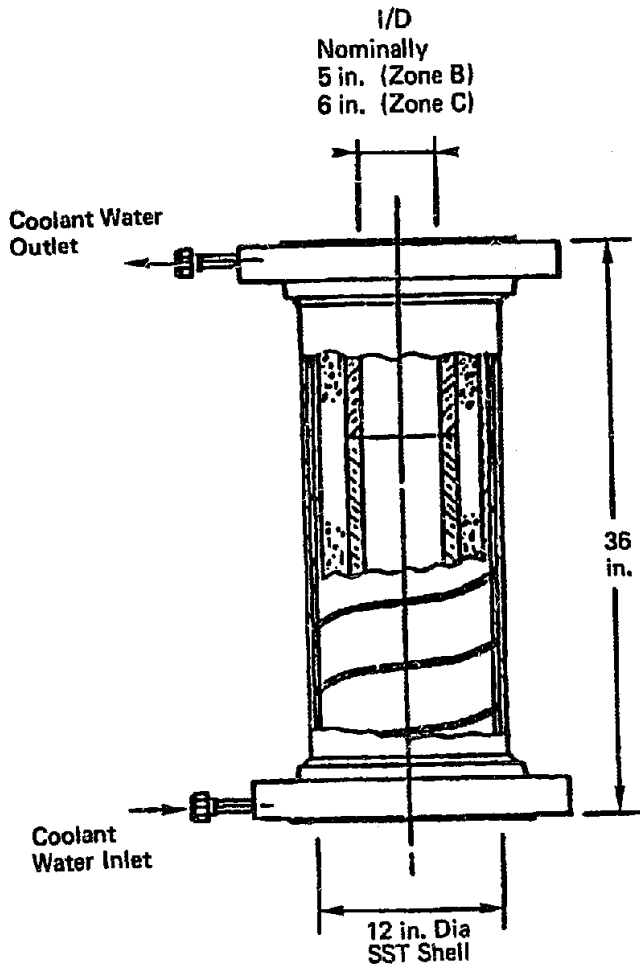
- Zone A Chamber with Inner and Outer Stainless Steel Shells with 0.125 in. Cooling Gap
- 0.125 in. Dia Wire Helix Wrapped between Shells to Provide Water Coolant Flow Passage
- Stainless Steel Flanges
- Chamber Pressure Pickup in Flange

Figure 5.3-3 Reactor Head Assembly and Water Cooled Zone A Cylindrical Section



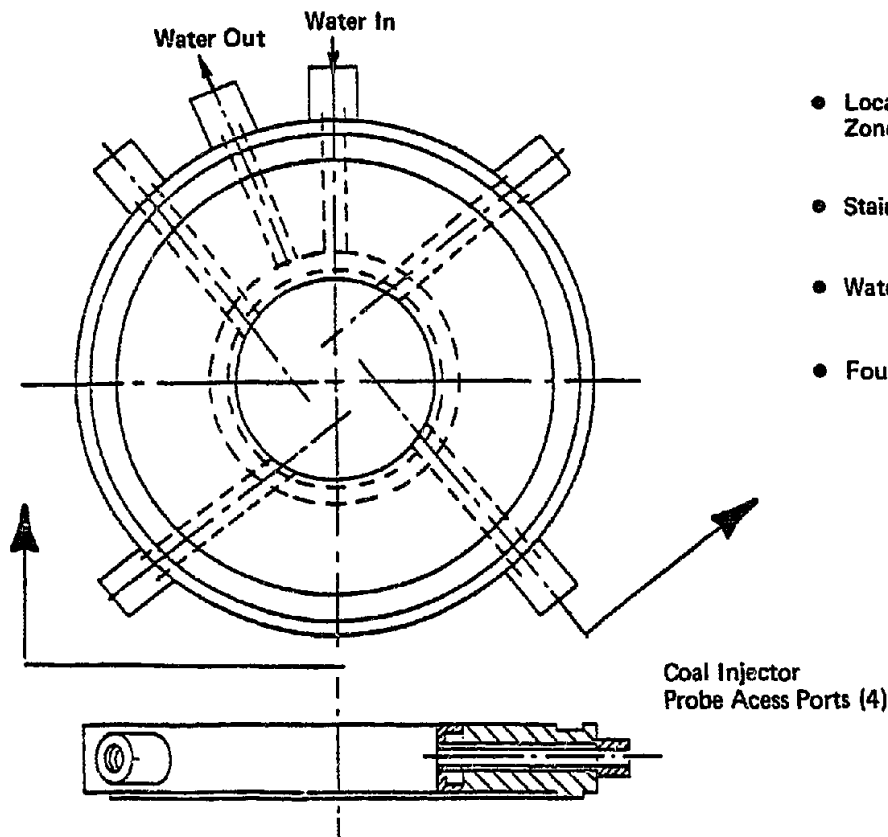
- Steam Injector
 - Stainless Steel
 - Water Cooled
 - Multiple Radial Injector Ports
 - Superheated Steam 500°F
- Transition Section
 - Adapter between Small Diameter and Large Diameter Reactor Chambers
 - Stainless Steel Inner Shell Water Cooled
 - 0.125 in. Dia Wire Helix Wrapped between Shells to Provide Water Coolant Flow Passage
 - Harbison Walker Ruby Plastic Alumina-Chrome Liner

Figure 5.3-4 Steam Injector and Zone B Transition Section



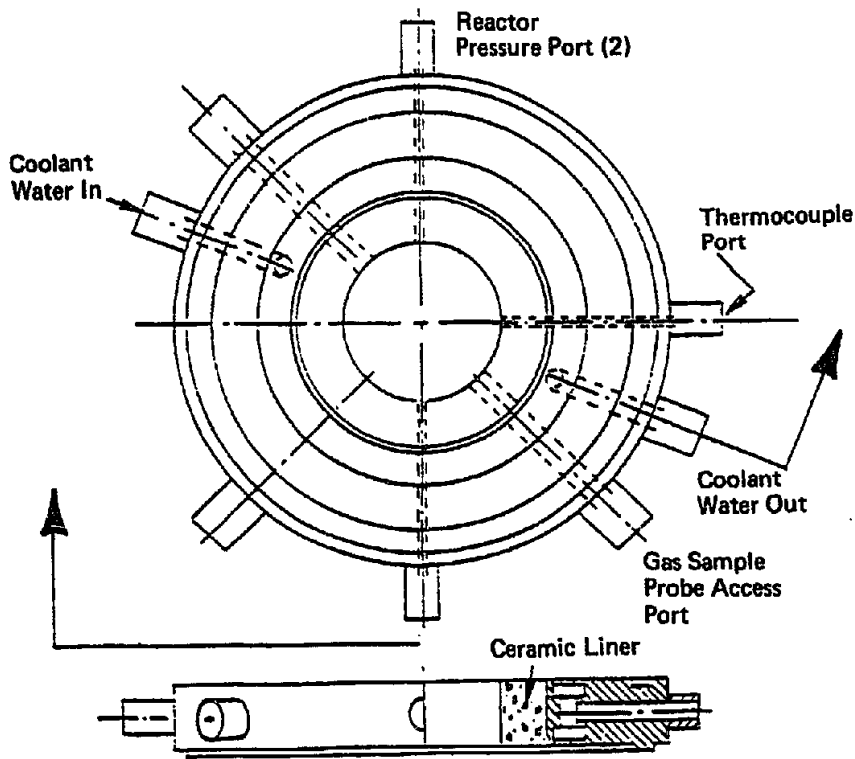
- Outer and Inner Shells Stainless Steel with 0.125 in. Gap
- 0.125 in. Dia Wire Wrapped in Helix between Shells to Provide a Water Coolant Flow Passage
- Water Flowrate \approx One Pound/Second
- Water Velocity \approx Five Feet/Second
- Alumina Chrome Inner Ceramic Liner
- Castable High Alumina Ceramic between Inner Ceramic Liner and Steel Shell
- Flanges Carbon Steel
- Maximum Operating Pressure - 750 psia
- Two Sections Required for both Zone A and Zone B

Figure 5.3-5 Zone B and Zone C Cylindrical Sections



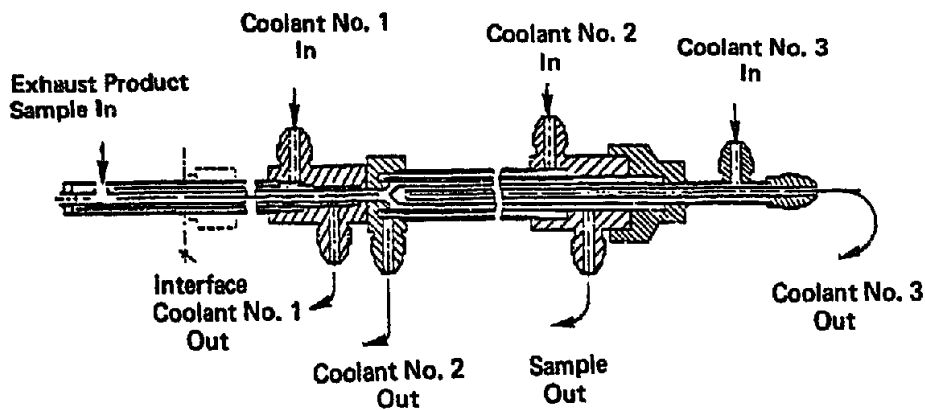
- Located between Zone B and Zone C Chambers
- Stainless Steel
- Water Cooled Inner Liner
- Four Coal Injection Ports

Figure 5.3-6 Secondary Coal Injector



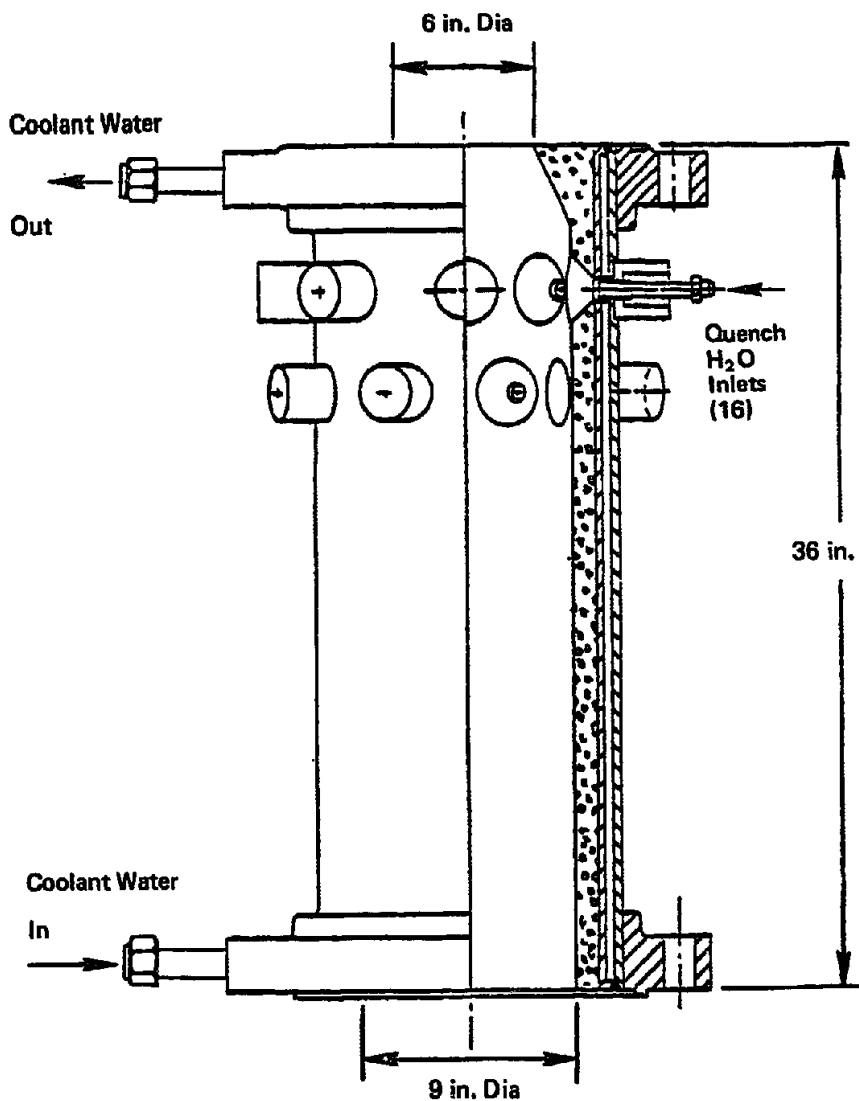
- Located at Exits of Zone B and Zone C
- Zone B Ring has 5 in. ID Alumina Chrome Liner
- Zone C Ring has 6 in. ID Alumina Chrome Liner
- Water Cooled Stainless Steel Ceramic Backup
- 2 Gas Sample Probe Ports
- 2 Chamber Pressure Measurement Ports
- 1 Gas Temperature Measurement Port

Figure 5.3-7 Instrumentation Ring



- 310 Stainless Steel
- Located at Exits of Zone B and Zone C
- Water Cooled Circuits for Rapid Quench of Exhaust Gas Species

Figure 5.3-8 Water Cooled Gas Sample Probe



- Inner and Outer Shells Stainless Steel with 0.125 in. Gap for Water Coolant
- 0.125 in. Wire Wrapped in Helix between Shells to Provide Water Coolant Flow Passage
- Water Flowrate ~ 2.5 lb/sec
- Carbon Steel Flanges
- Castable High Alumina Ceramic Liner Contoured at Injector Water Inlets to Accommodate Spray Cone
- 16 Water Spray Injector Nozzles for Rapid Quench of Product Gas from 2500°F to 500°

Figure 5.3-9 Water Quench Section

5.3.4 Gasifier Starter

High temperature conditions, required to initiate coal/oxygen gasification reactions, are obtained by sequentially firing two solid grain gas generators (Figure 5.3-10) into the head end of the gasifier.

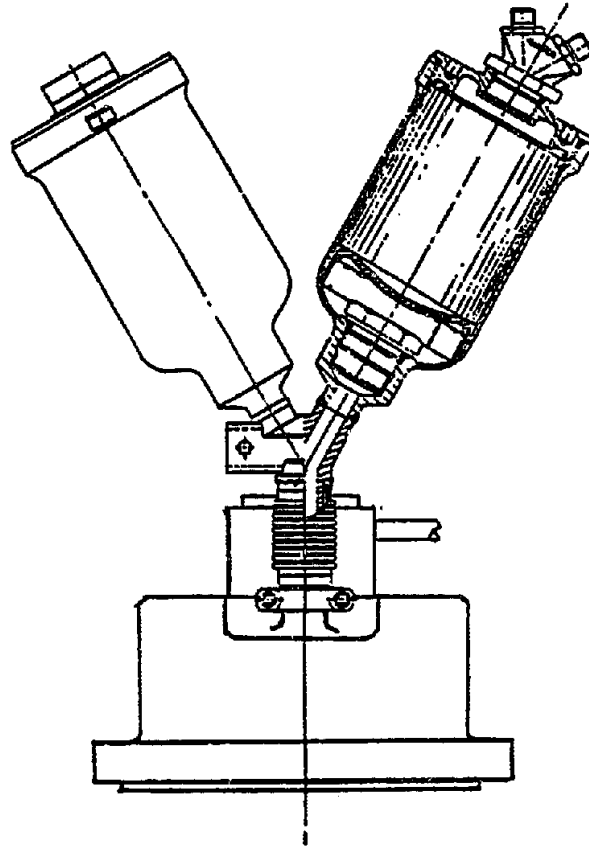


Figure 5.3-10 Solid Grain Gasifier Starter

The gas generators are identical to the initiators used to start Bell's Agena rocket engine and are comprised of an initiation squib, igniter and a solid propellant charge. A twenty-eight volt dc signal, fed to the initiation squib, causes two parallel bridge wires to heat up and ignite a zirconium and ammonium perchlorate bead. Heat from this reaction ignites a boron and potassium chlorate charge which in turn ignites a mixture of smokeless powder. This in turn ignites the main solid propellant charge. The main charge is an OGK double base solid grain of nominally 1.3 lb weight which burns for 1.5 seconds. The solid charges are loaded into starter containers mounted at the head end of the reactor and when fired, in sequence with proper amounts of oxygen and coal create the temperature conditions required to initiate gasification.

5.4 GASIFIER FABRICATION

The reactor head assembly, used during the company sponsored oxygen blown program, was modified to accommodate a tongue and groove gasket installation. This was the only modification necessary to prepare this unit for use in the subject program.

The Zone A cylindrical section, steam injector and transition section were fabricated, pressure tested and their respective coolant water jackets flow checked.

Figure 5.4-1 shows the reactor head, steam injector, Zone A cylindrical section and transition section being assembled prior to installation in the process development unit.

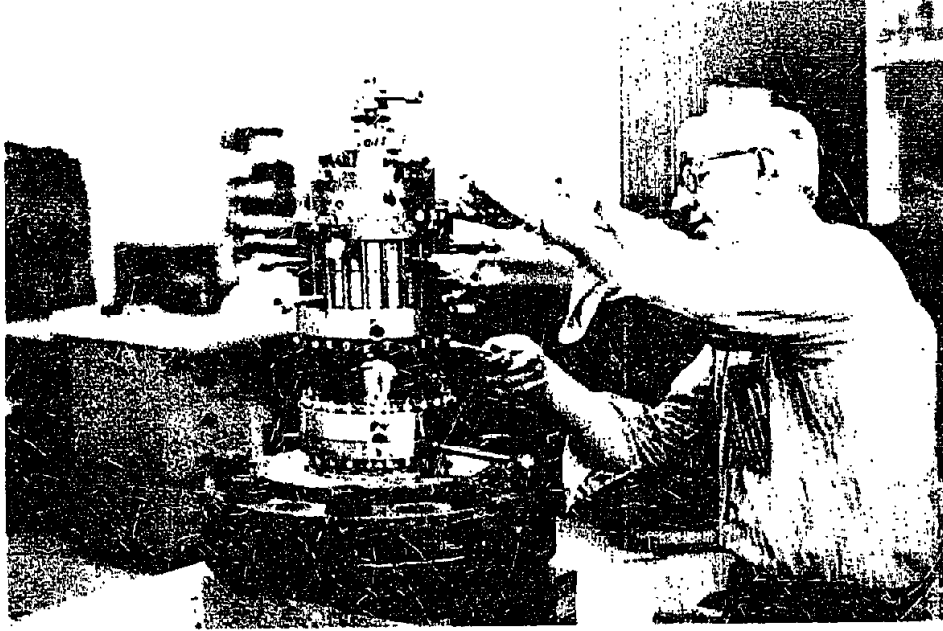


Figure 5.4-1. Assembly of Upper Reactor Units

Following fabrication of the four three-foot long reactor cylindrical section shells (Figure 5.4-2). The units were hydro-tested to 1125 psi and the water coolant jackets flow checked to establish pressure drop versus flow relationships.

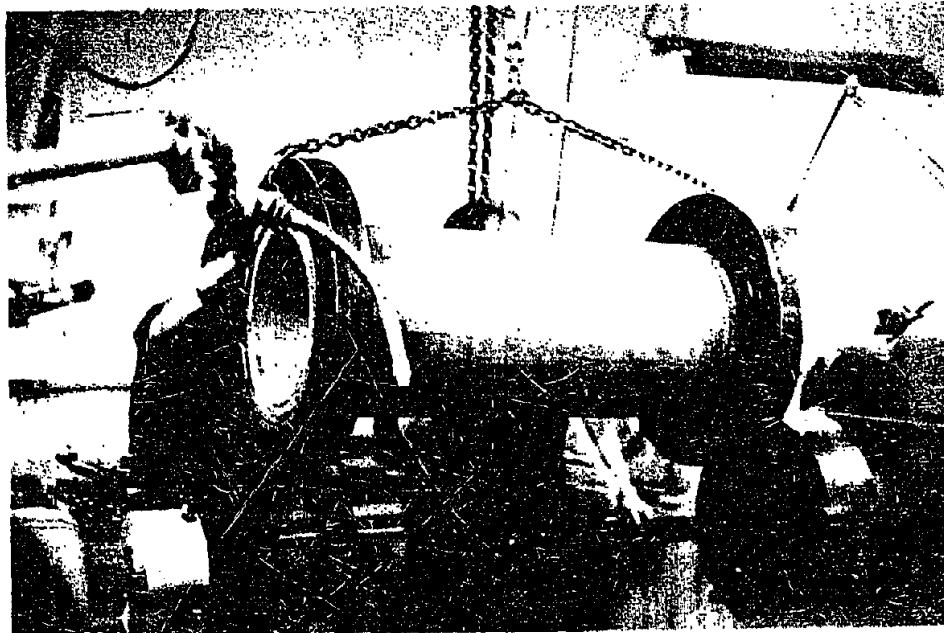


Figure 5.4-2. Water Cooled Reactor Shell Section

Ceramic liners were then installed in all four cylindrical sections (Figure 5.4-3).

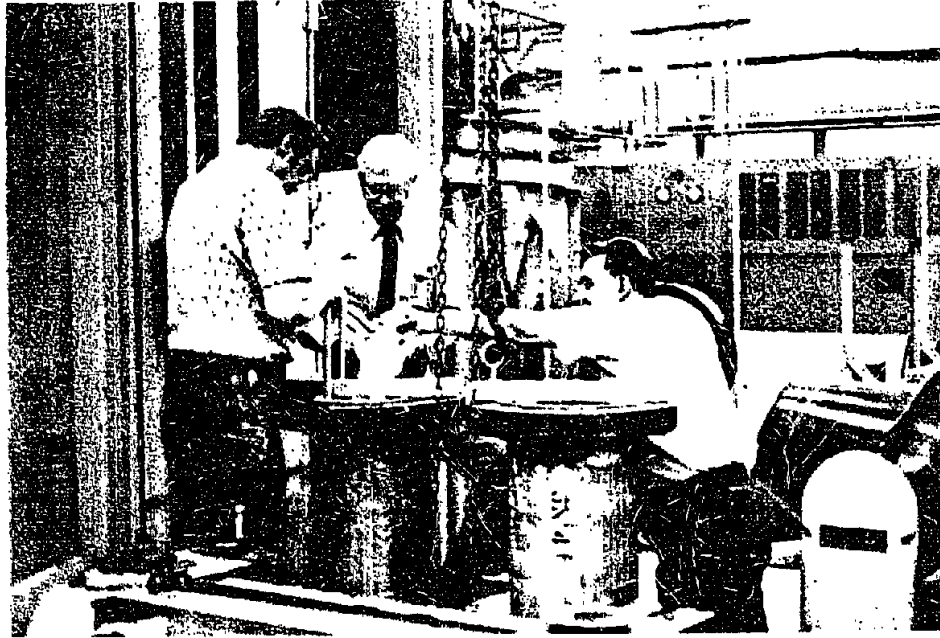


Figure 5.4-3. Packing Castolast G around Reactor Alumina Liner

The core ceramic liner is made of Didier Taylor Shamrock 882, which is a chrome alumina vibratable plastic. The core liners are five inches internal diameter, by one inch thick for Zone B chambers and six inches internal diameter by one inch thick for Zone C chambers. Core liners were cast as one foot long cylinders and fired at 2800°F. The liners were centrally located within the steel cylindrical sections and were locked in position by pouring and packing Harbison-Walker Castolast G into the annular gap between the Shamrock core liner and the steel shell (Figure 5.4-4).

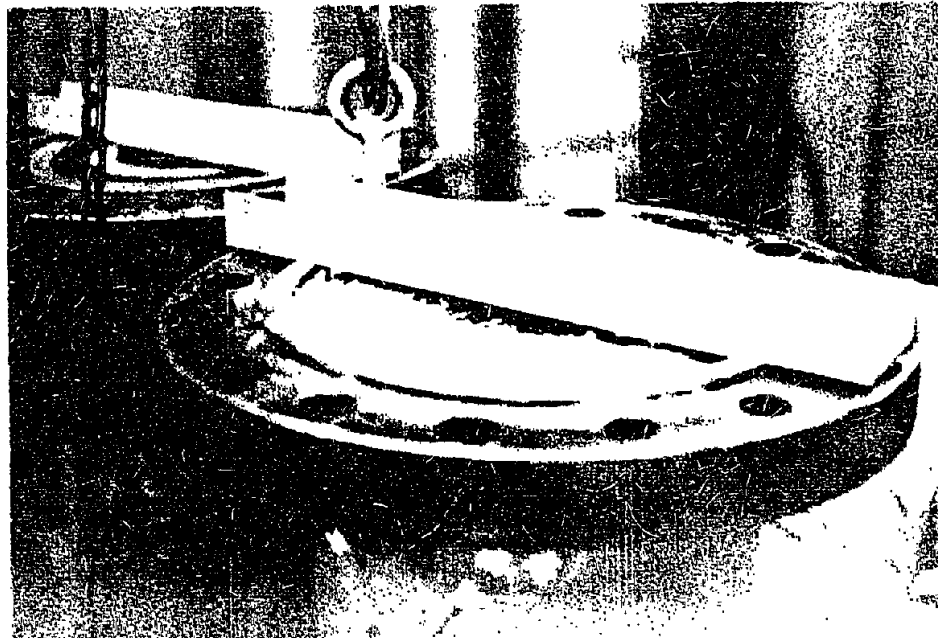


Figure 5.4-4. Completed Reactor Section with Liner

Two instrumentation rings (Figure 5.4-5) were fabricated and after flow checking the water-cooled jackets were lined with Harbison-Walker chrome alumina refractory plastic.

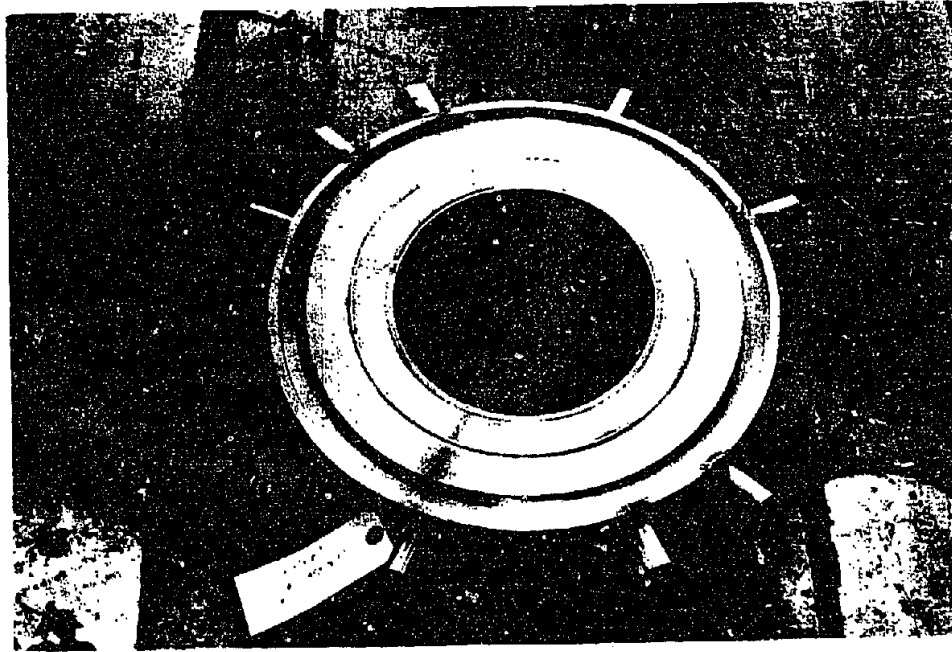


Figure 5.4-5. Instrumentation Ring with Chrome Alumina Liner

The shell of the three foot long water quench section was fabricated and the housings for sixteen water spray nozzles were installed (Figure 5.4-6).

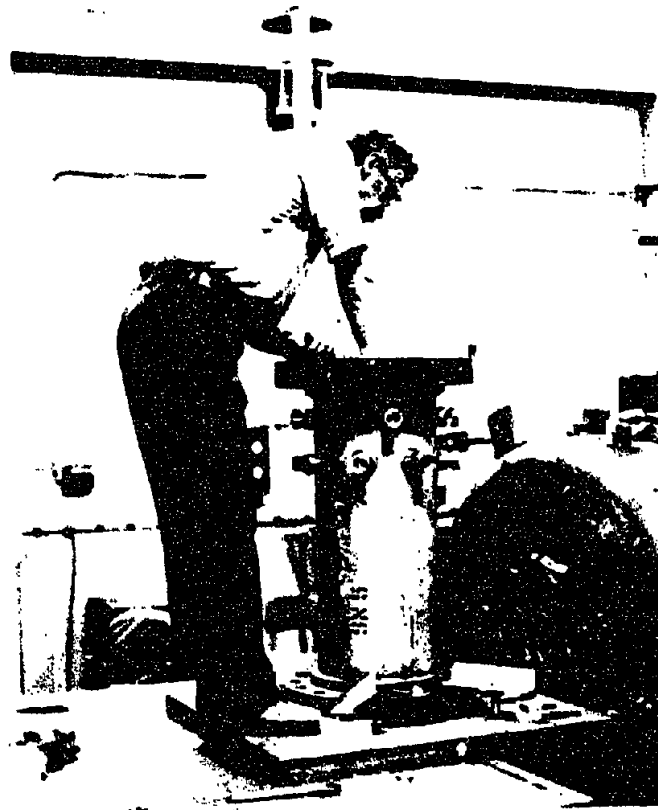


Figure 5.4-6. Water Quench Section with Water Spray Nozzle Housings

The unit was hydrotested to 1125 psi and the water coolant jacket flow checked. The quench section was then lined with Harbison-Walker Castolast G, into which steel fibers were mixed to provide added structural strength. Conic recesses were contoured in the ceramic liner around each of the sixteen spray nozzle entry points (Figure 5.4-7) to ensure that the water spray would not impinge onto the ceramic liner.



Figure 5.4-7. Quench Section Liner showing Contoured Nozzle Parts

5.5 TEST FACILITY DESIGN

5.5.1 Facility Modifications

The Bell gasification test facility, originally used for air-blown testing and modified under company sponsorship for oxygen-blown testing, was further upgraded for the subject DOE/GRI program. The initial concept for the upgraded Process Development Unit (PDU) is shown schematically in Figure 5.5-1.

Equipment existing at program initiation is indicated by cross-hatches. New pieces of facility equipment were added to enable reactor solid and condensable products to be collected and evaluated, and to facilitate computation of a material balance for the overall process. Functions and specification outlines for the slag tank, cyclone and condenser added to the PDU are identified in Figures 5.5-2, 5.5-3 and 5.5-4.

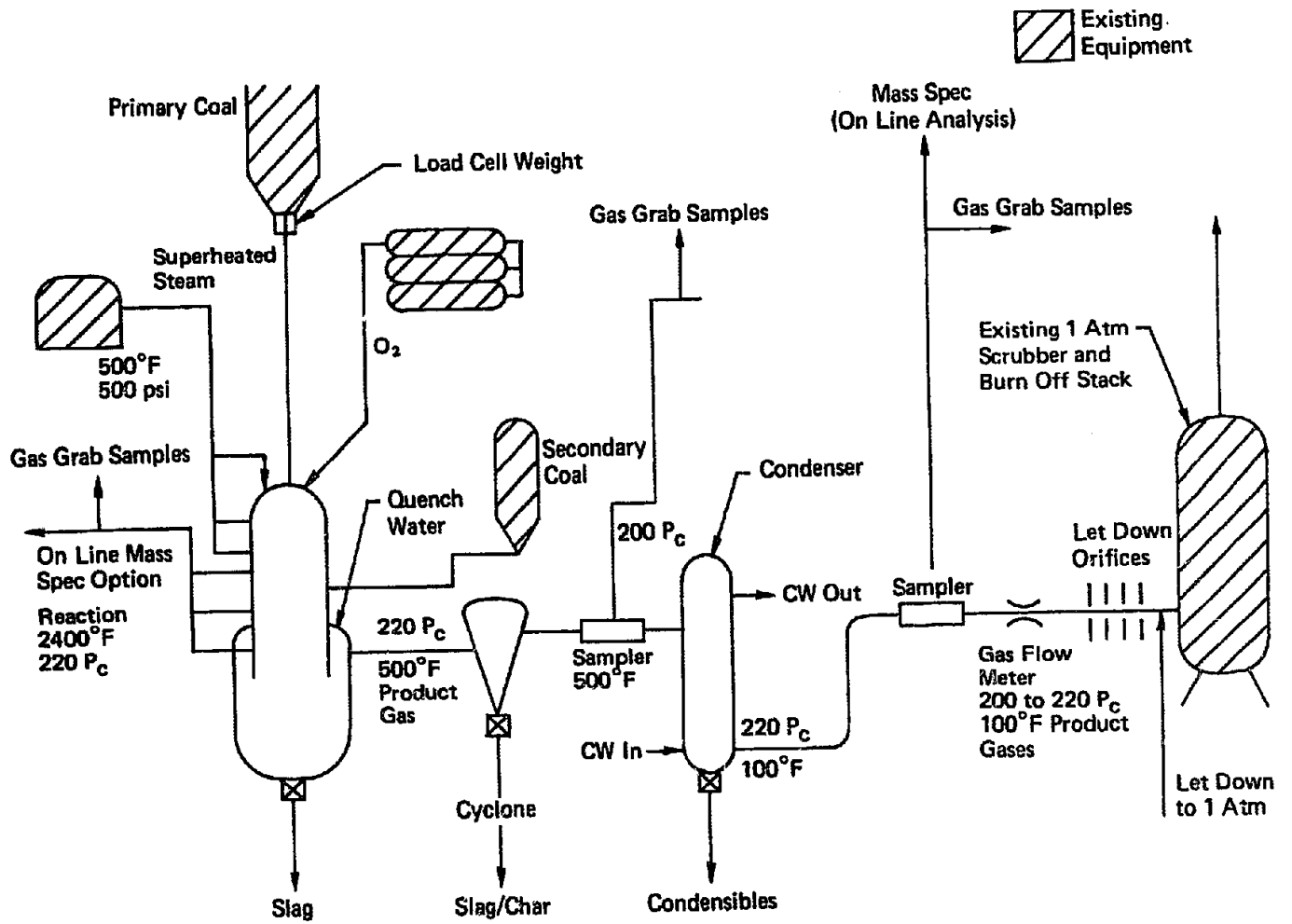
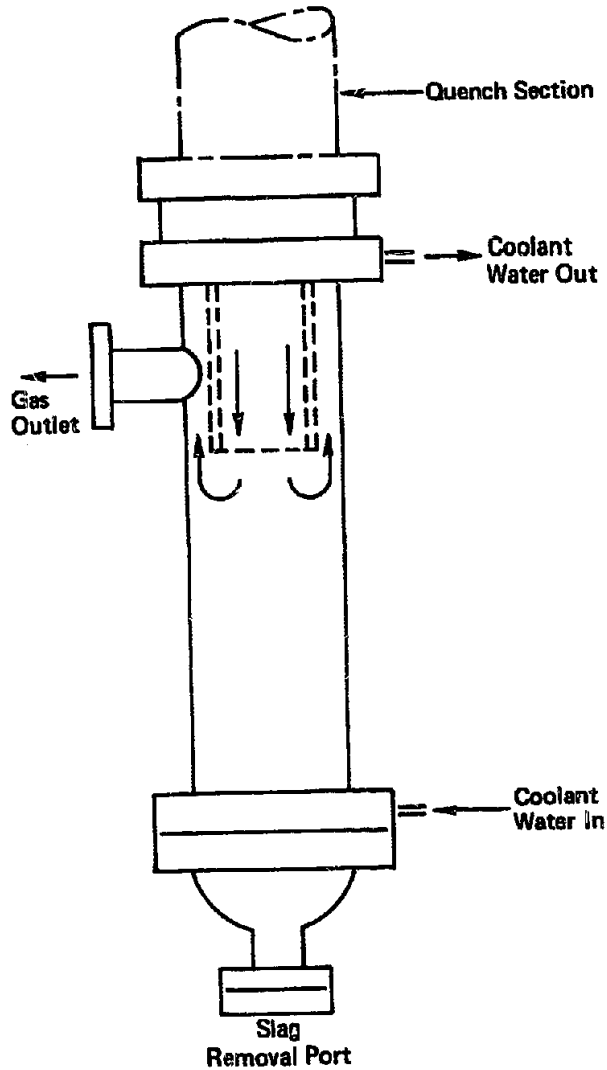
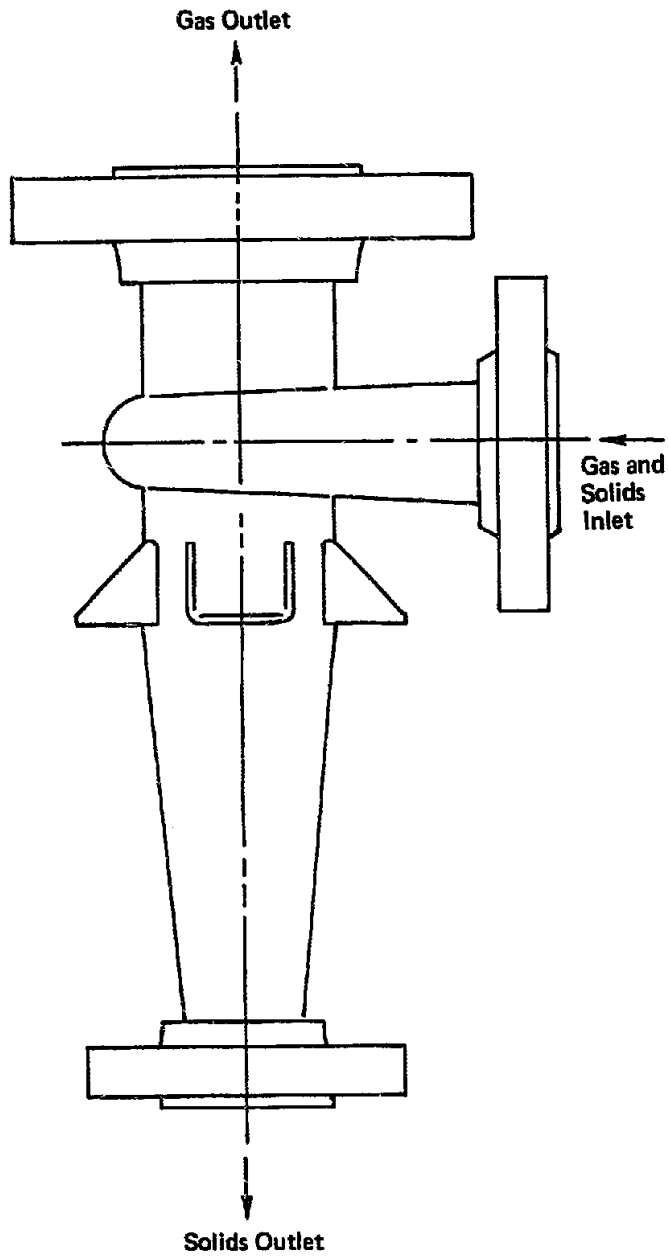


Figure 5.5-1 Upgraded Test Facility Schematic



- **Function**
 - Reduce Reactor Product Gas Temperature from 2500°F to 500°F using Water Quench
 - Drop Out Proportions of Product Gas Solids by Reversing Gas around Baffle Tube
- **Features**
 - Slag Tank Walls are Water Cooled Stainless Steel
 - Maximum Operating Pressure - 750 psia
 - Maximum Gas Temperature - 700°F
- **Post Test Evaluation**
 - Remove Collected Solids and Liquids from Slag Removal Port and Quantify Slag, Char and Water – Data used in Mass Balance

Figure 5.5-2. Quench Section and Slag Collection Tank



- Function
 - Remove Solids from Gas Stream
- Features
 - Cyclone Body Incaloy 800
 - Maximum Operating Pressure - 750 psia
 - Maximum Gas Temperature - 700°F
 - Gas Inlet Velocity 50 Feet/Second
 - Fractional Efficiency

Stokes Equivalent Dia (Microns)	% Efficiency (Weight)
15	98
7	90
4	77
2	50

- Post Test Evaluation
 - Remove Collected Solids and Quantify Char and Slag
 - Data used in Mass Balance

Figure 5.5-3 Cyclone

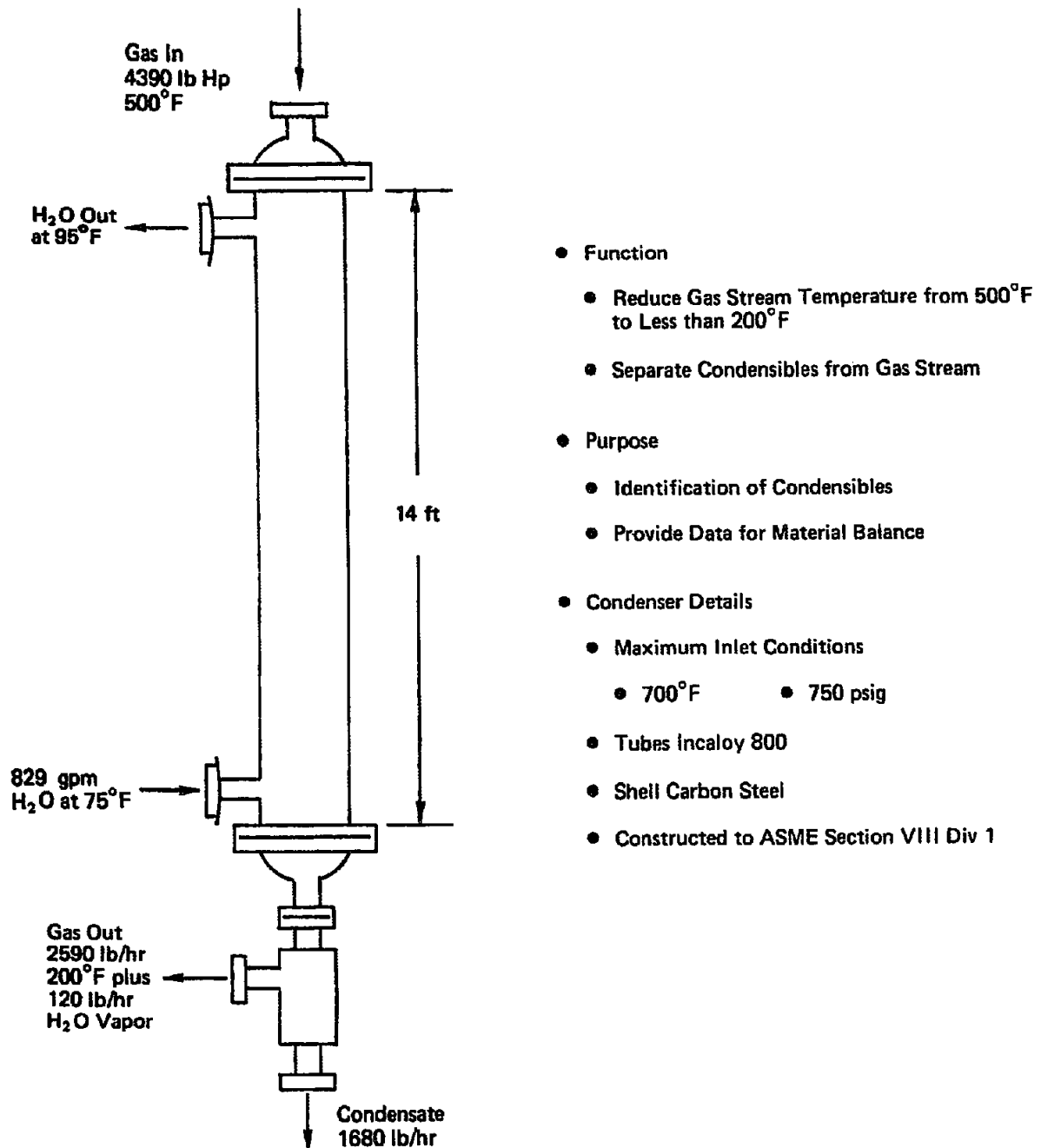


Figure 5.5-4. Condenser

5.6 TEST FACILITY ASSEMBLY

Modification of the gasifier test facility used for previous air-blown and oxygen-blown testing, began in January 1980, when components of the atmospheric pressure product gas handling equipment were removed. A large crane was employed for this task and was also used to remove the forty cubic foot capacity coal load tank from the coal feed building. The coal load tank was to be used as the secondary coal feed tank, during the test program, and its removal was necessary to enable a weigh system to be installed to facilitate the measurement of secondary coal feed rates.

Cold weather and snow delayed the pouring of concrete foundations for new facility equipment and the reactor building extension by approximately four weeks. Once the foundations were poured, however, the cyclone and interim condenser were installed, the atmospheric scrubber was repositioned and the coal load tank was installed on the new weigh system, in the coal feed building. Burn-off stack installation is shown in Figure 5.6-1. The vertically mounted condenser and its support frame are seen in the right foreground.

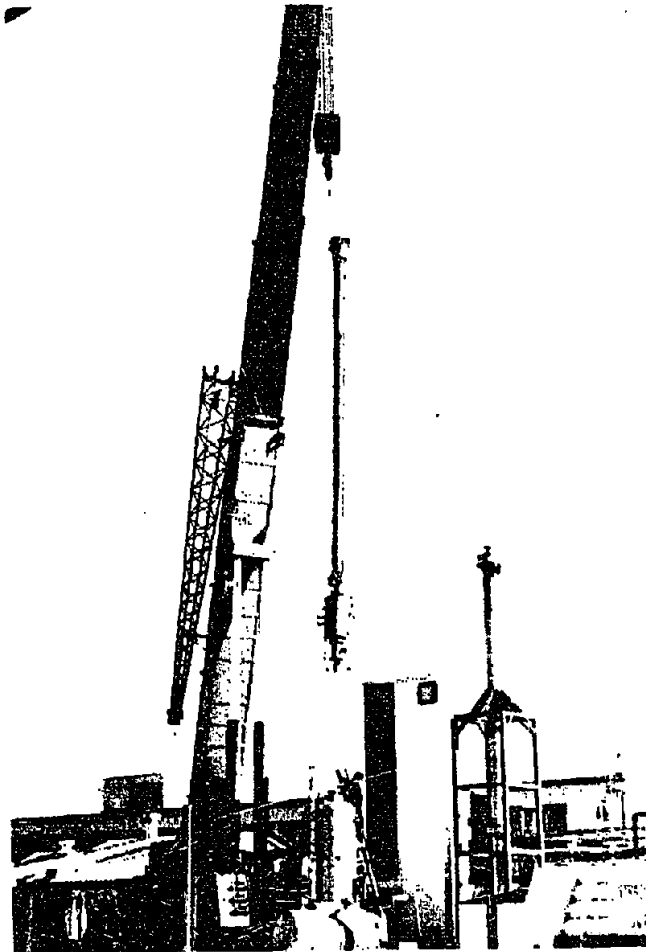


Figure 5.6-1. Burn-off Stack Installation

The metal framework of a Bell supplied test stand extension, required to house the large two-stage gasifier, was fabricated off-site and during the last week of March was brought on site and installed. Figure 5.6-2 shows the building framework being positioned. The addition of siding, floors, electric power, hoists, valves and controls, etc., was completed during the ensuing six weeks.

Fabrication of the PDU control console, which incorporates an automatic programmable logic controller, was completed during early May. The console was successfully checked out in the electrical assembly area before installation in the PDU control room (Figure 5.6-3).

Installation and checkout of all gas transfer lines, valves and controls between the reactor, the cyclone, the condenser, the demister and the scrubber were completed by mid-June (Figure 5.6-4).

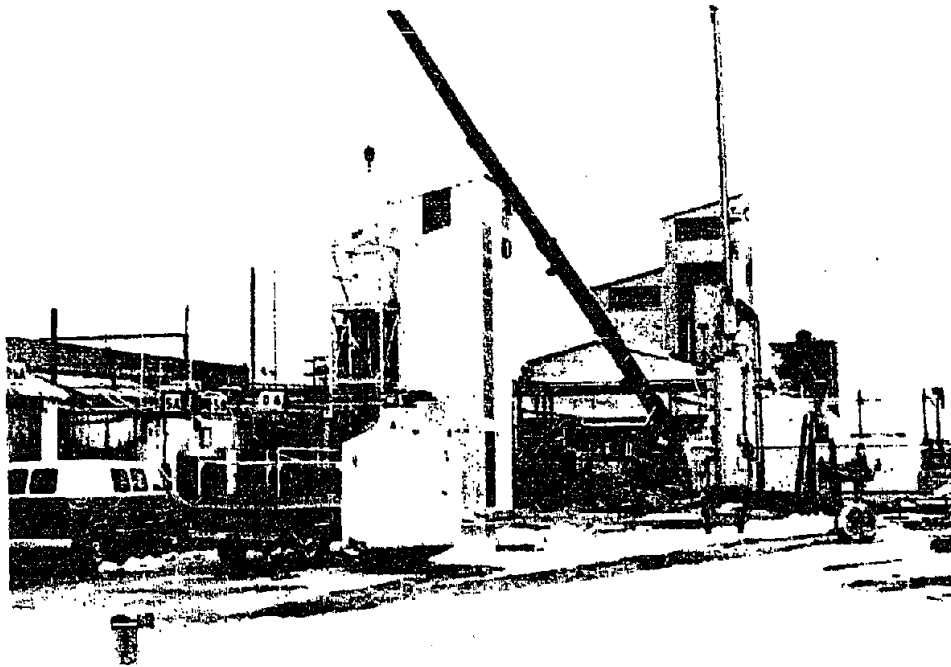
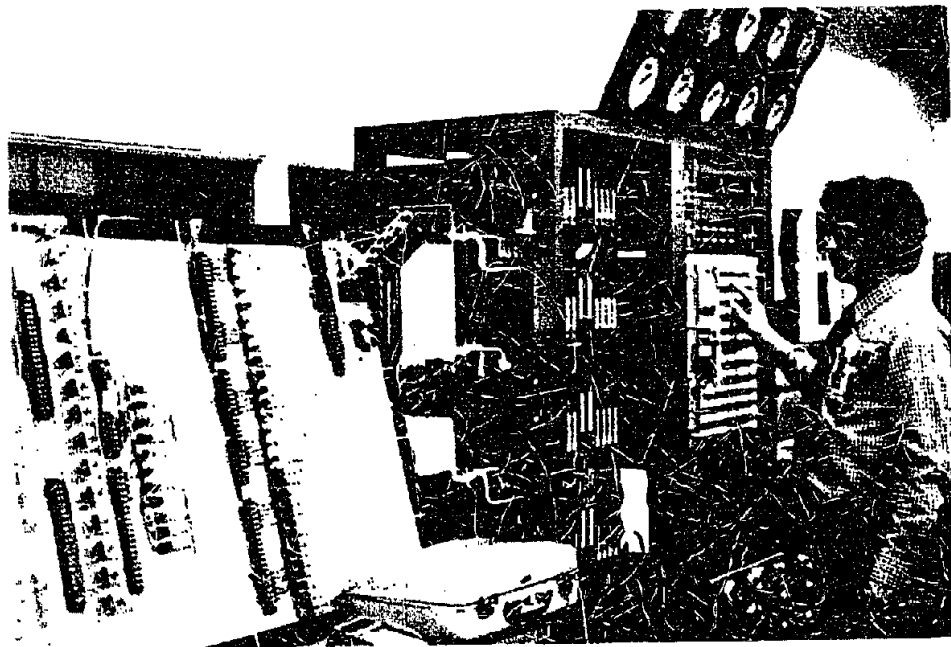
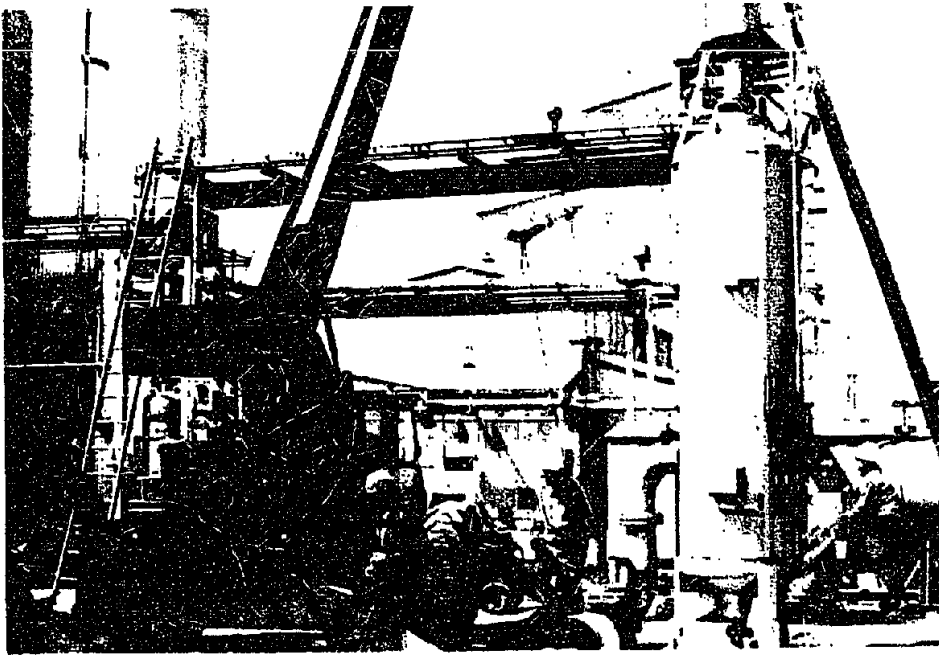


Figure 5.6-2. Reactor Building Extension Framework being Installed



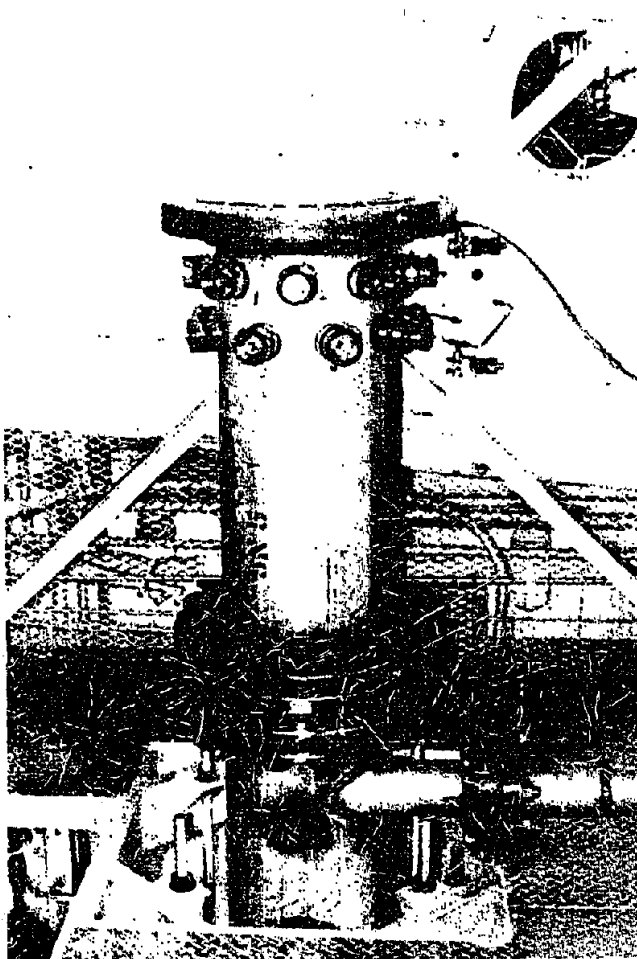
- Start and Shutdown Sequences Pre-programmed

Figure 5.6-3. Checkout of Control Console using PDU Breadboard



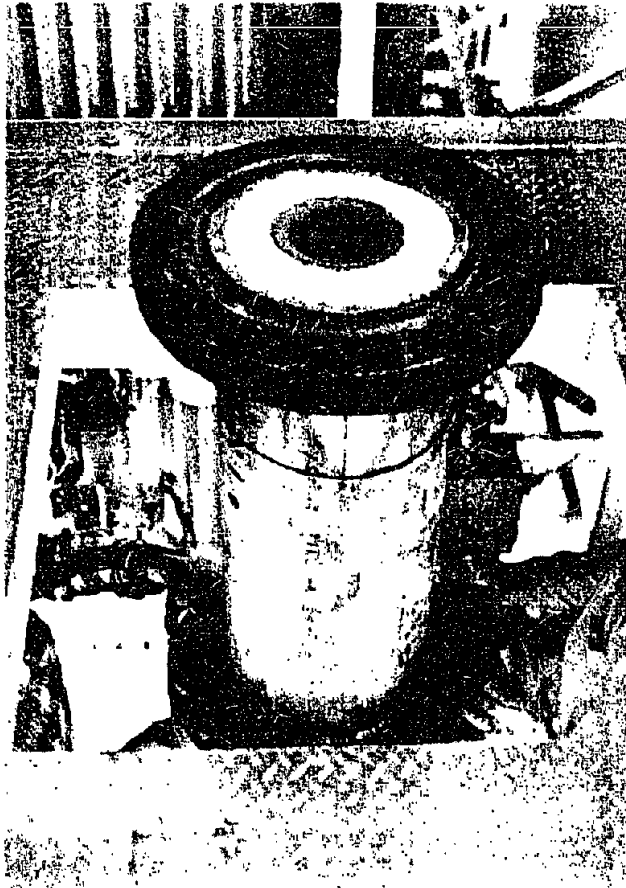
**Figure 5.6-4.
Installation of Gas
Transfer Lines**

The modularized High Mass Flux gasifier was assembled in the reactor building during early June (Figures 5.6-5, 5.6-6, and 5.6-7).



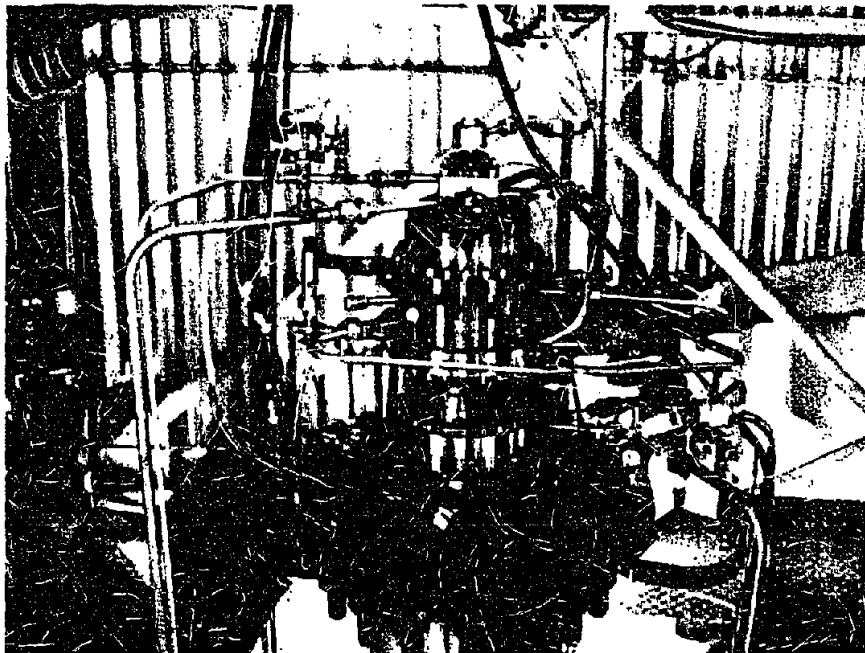
- Water Cooled Ceramic Lined Quench Section
- Sixteen Water Spray Nozzles
- Water Cooled Slag Tank

**Figure 5.6-5. Quench Section Mounted on
Slag Tank**



- Water Cooled Shell
- Chrome Alumina Liner
- Alumina Castable Back-up

Figure 5.6-6.
Zone B Cylindrical Section Installation



- Coal, Oxygen and Steam Injectors
- Water Cooled Head and Upper Chamber Section
- Ceramic Lined Transition Section

Figure 5.6-7.
Gasifier Head Installation

Reactant feed lines, purge lines, water coolant lines and instrumentation were installed. Pressure tests and dry functional tests were completed by late June.

Figure 5.6-8 shows the completed High Mass Flux PDU.

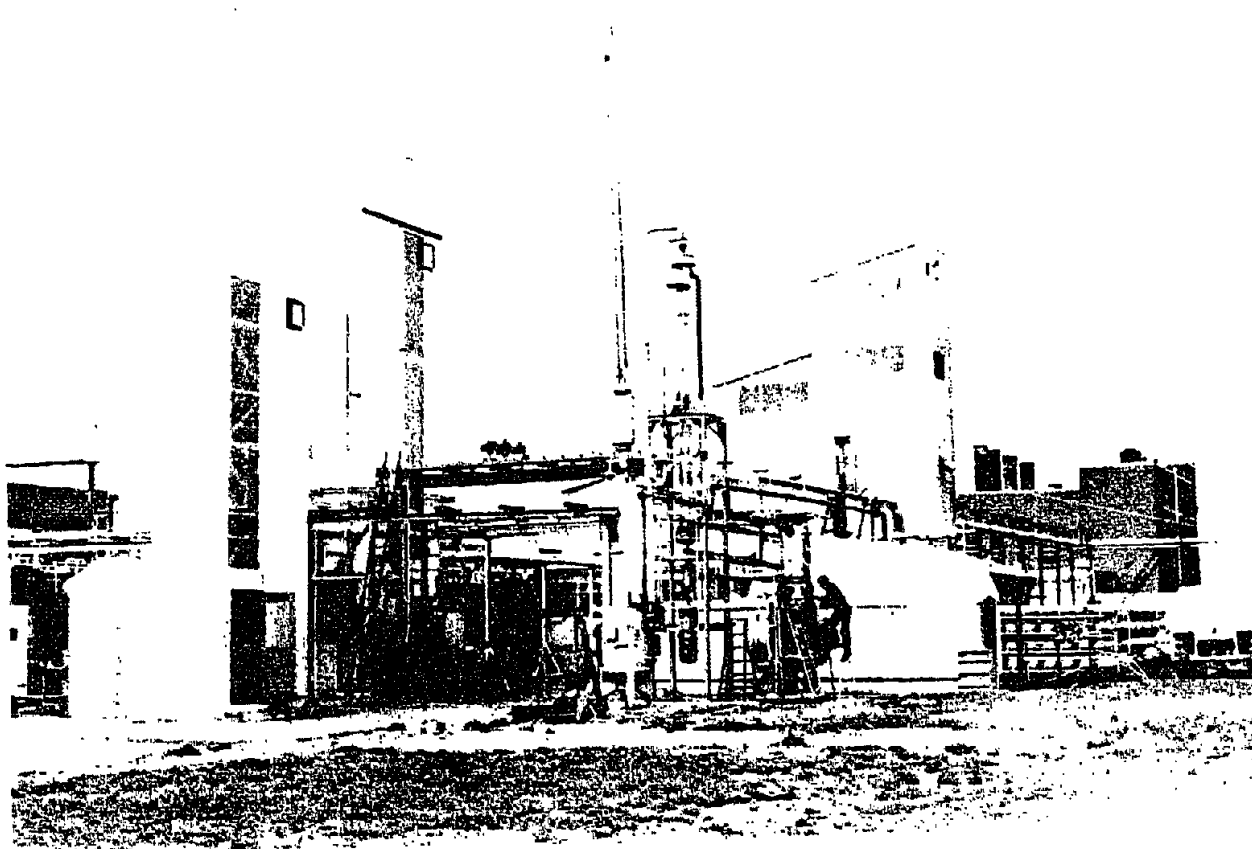


Figure 5.6-8. High Mass Flux Gasifier Process Development Unit

5.7 DATA ACQUISITION AND ANALYSIS

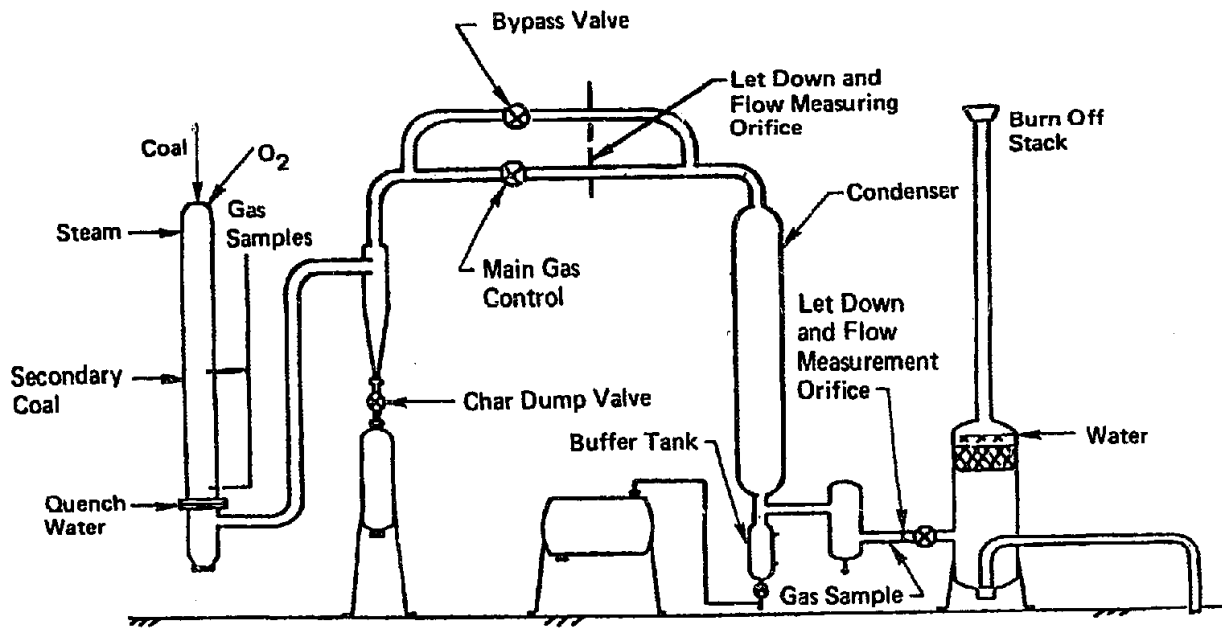
5.7.1 Material Measurement and Analysis

A schematic layout of the PDU from the gasifier to the scrubber, is shown in Figure 5.7-1. Stations at which gasifier inputs and outputs are measured are indicated.

Measurement and analysis methods employed to provide the necessary data to perform a material balance and performance analysis are summarized in the following.

5.7.1.1 Gasifier Input Measurements

- Oxygen, Superheated Steam, Auxiliary Air, Nitrogen
- Pressure and temperature measurements, taken upstream of calibrated sonic orifices, used to compute flowrates.



Reactor In	Slag Tank Out	Cyclone Out	Condenser Out	Demister Out	Gas Out	Scrubber In	Scrubber Out
Coal Oxygen Steam Air Nitrogen Quench Water	Slag Char Water	Char Slag Water	Water Condensable Hydrocarbons Char Slag Soluble Gas	Water	H ₂ CO CO ₂ CH ₄ H ₂ O N ₂ Fly Ash	Water	Product Gas Water Fly Ash
Flowrate	Weight	Weight Chemical	Weight Chemical	Weight	Flowrate Species	None	None

Figure 5.7-1. High Mass Flux Gasifier PDU Schematic

- Primary and Secondary Coal Flowrates
 - 1400 lb capacity pulverized coal feed tanks mounted on weigh scales.
 - Scale outputs monitored to obtain coal flowrates.
 - Pressure drop across calibrated coal venturi orifices also used to assess instantaneous coal flowrates.
- Quench Water Flowrate
 - Monitored by turbine type flowmeter. Instantaneous and integrated flows computed.

5.7.1.2 Gasifier Output Measurements

- **Slag Tank Content Measurement and Analysis**
 - Transfer all accumulated solids and liquids from slag to holding tank – weigh and record.
 - Thoroughly mix tank contents. Extract two 1000 cc samples in glass jars with screw caps. Identify.
 - One sample is retained; the other analyzed as follows:
 - Percent Moisture – ASTM D-3173
 - Percent Ash – ASTM D-3174
 - Percent Carbon – By Difference
 - Selected samples subjected to ultimate analysis per ASTM D-271, to determine C, H, N, S, and ash.
- **Char Tank Content Measurement and Analysis**
 - Transfer all accumulated solids from char holding tank to drum – weigh and record.
 - Thoroughly mix drum contents. Extract two 1000 cc samples in glass jars with screw caps. Identify.
 - One sample is retained; the other analyzed as follows:
 - Percent Moisture – ASTM D-3173
 - Percent Ash – ASTM D-3174
 - Percent Carbon – By Difference
 - Selected samples subjected to ultimate analysis per ASTM D-271, to determine C, H, N, S, and ash.
- **Condensate Measurement and Analysis**
 - Transfer contents of condensate buffer tank, holding tank, and demister tank to collection vessel. Weigh and record.
 - Thoroughly mix contents. Extract two one-liter samples in glass bottles with screw caps. Identify.
 - One sample is retained; the other analyzed as follows:
 - Extract insoluble liquid phase – analyze by IR spectrometer
 - Measure pH
 - Analyze for dissolved gases (NH₃, H₂S, HCN)
 - Centrifuge – weigh suspended solids

- **Product Gas Flowrate Measurement**
 - Measure pressure and temperature upstream of sonic orifice.
 - Calculate molecular weight from mass spectrometer analysis.
 - Flow rate = $K\sqrt{MP/T}$, where K includes orifice area and discharge coefficient.
 - Total gas flowrate obtained by integration of flowrates.
- **Product Gas Analysis Using On Line Mass Spectrometer**
 - Product gas at scrubber measuring orifice bled continuously through heated line to mass spectrometer during test.
 - Spectrum scanned every two minutes for H₂, CH₄, H₂O, CO, N₂, O₂, CO₂.
 - Calibrated with standard gas mixtures.
 - Data analyzed by COSMIC program GSC-11279.
- **Product Gas Grab Samples Collection and Analysis**
 - Gas grab samples taken at gasifier Zone B, Zone C, and product gas outlet.
 - Three samples per test at each location.
 - Analyzed by HP-5840A gas chromatograph for CO, CO₂, CH₄, O₂, H₂, N₂, H₂S.
 - Instrument check calibrated before each test series with standard gas mixtures of known composition.

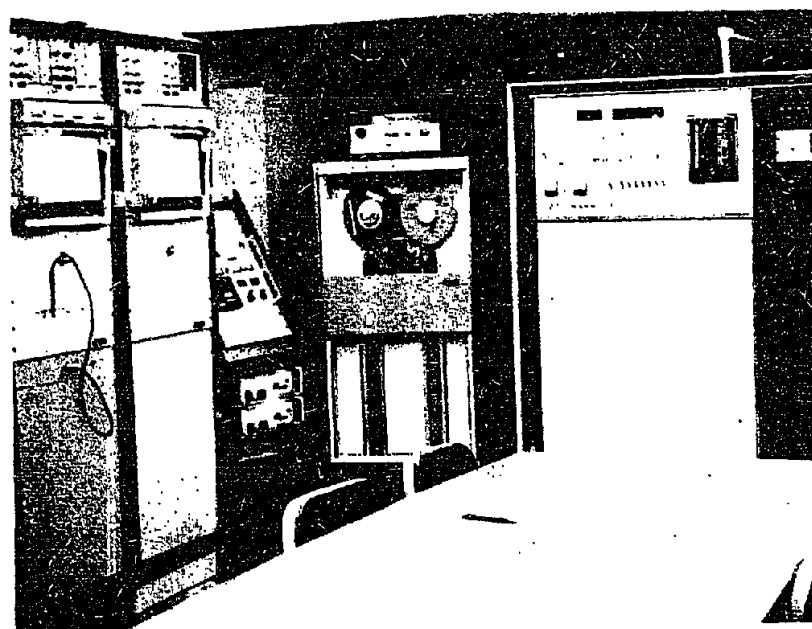
5.7.2 Levels of Material Balance

Data obtained by the methods described in paragraph 5.7.1 are used to generate material balances at the following four levels:

- I - Overall system mass balance for complete test
- II - Overall system elemental mass balance for complete test
- III - Elemental mass balance for specific test intervals (periods when grab samples are taken)
- IV - Elemental mass balance for individual components (gasifier, cyclone, condenser)
Heat balances are also computed at overall and component levels.

5.7.3 Data Acquisition and Analysis Systems

Throughout a gasification test critical gasifier and test facility parameters are monitored on gauges in the PDU control room and strip charts in the instrumentation room. In addition, these measurements and other supporting parameters are recorded on a high speed digital data acquisition system. Post test, the digital tape is computer processed and a printout of reduced data is available within a few hours of test completion. (See Figures 5.7-2 and 5.7-3.)



- Critical Gasifier System Measurements Monitored on Brush Recorders and Digital Readout Displays
- Data Recorded on Digital and FM Tape for Post Test Data Reduction and Analysis

Figure 5.7-2. Data Monitoring and Acquisition Equipment

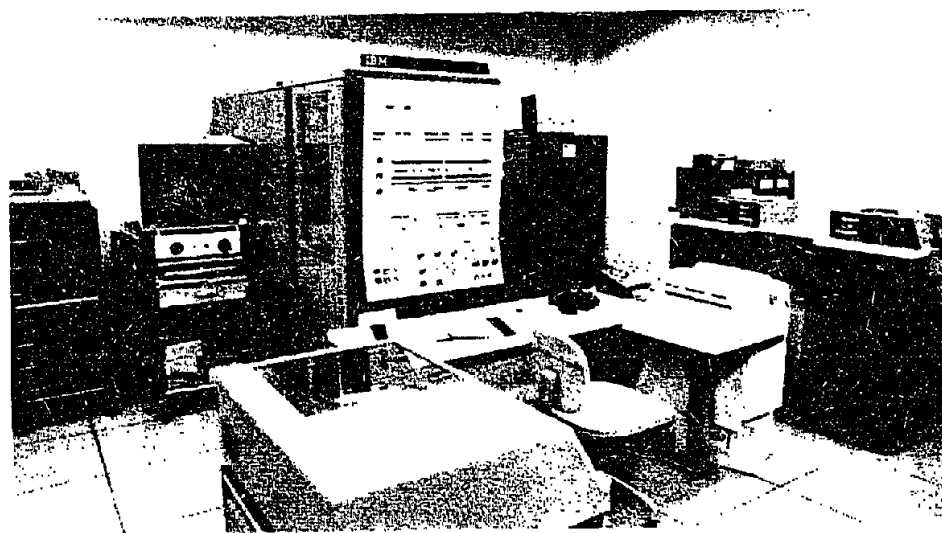


Figure 5.7-3. 360/44 Computer Located in Instrumentation Control Room used to Process Test Data and Control On-Line Mass Spectrometer

The on-line mass spectrometer (Figure 5.7-4) used to monitor gas species, is mounted adjacent to the PDU. Operation of the mass spectrometer is controlled by the 360/44 computer located in the instrumentation control room. The mass spectrometer output is recorded on digital tape and post test is analyzed using the COSMIC GSC-11279 program to quantify species.

Gas grab samples taken at two stations in the reactor and at the scrubber inlet are analyzed using a HP-5840A gas chromatograph (Figure 5.7-5) located in Bell's chemistry laboratory.

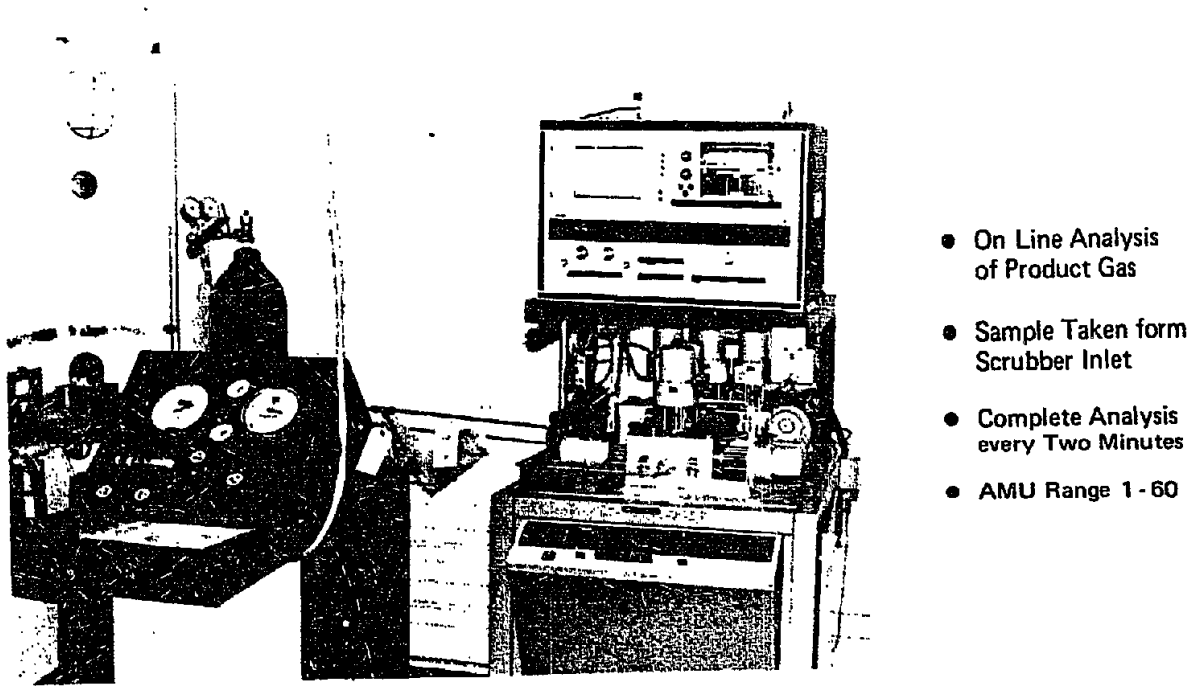


Figure 5.7-4. On Line Mass Spectrometer



Figure 5.7-5. Gas Chromatograph

5.8 PROCESS DEVELOPMENT UNIT OPERATION AND SAFETY ASSURANCE

A primary consideration during PDU design was safety. The facility, hardware and operating procedures all reflect this fundamental consideration.

A specific example of facility safety is the fact that primary reactant feed lines, i.e., oxygen and coal, use series redundant, normally closed, fail close shutoff valves. Conversely, the dual purpose isolation/control valves (main gas control and bypass) in the three inch product gas line are normally open, fail open valves. In the event of a power loss, the reactant valves would therefore close, thus terminating reactant inputs to the reactor, and the product gas valves would open which would vent the system pressure down to atmospheric pressure through the gas scrubber and burn-off stack. (See Figure 5.8-1.)

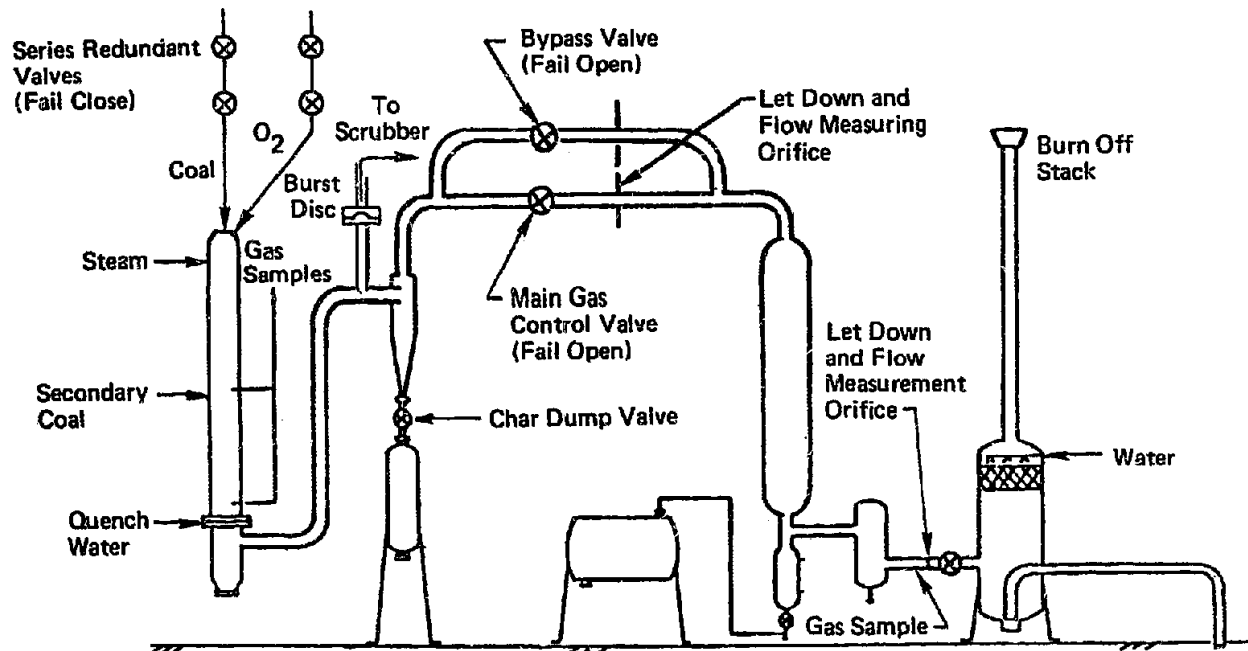
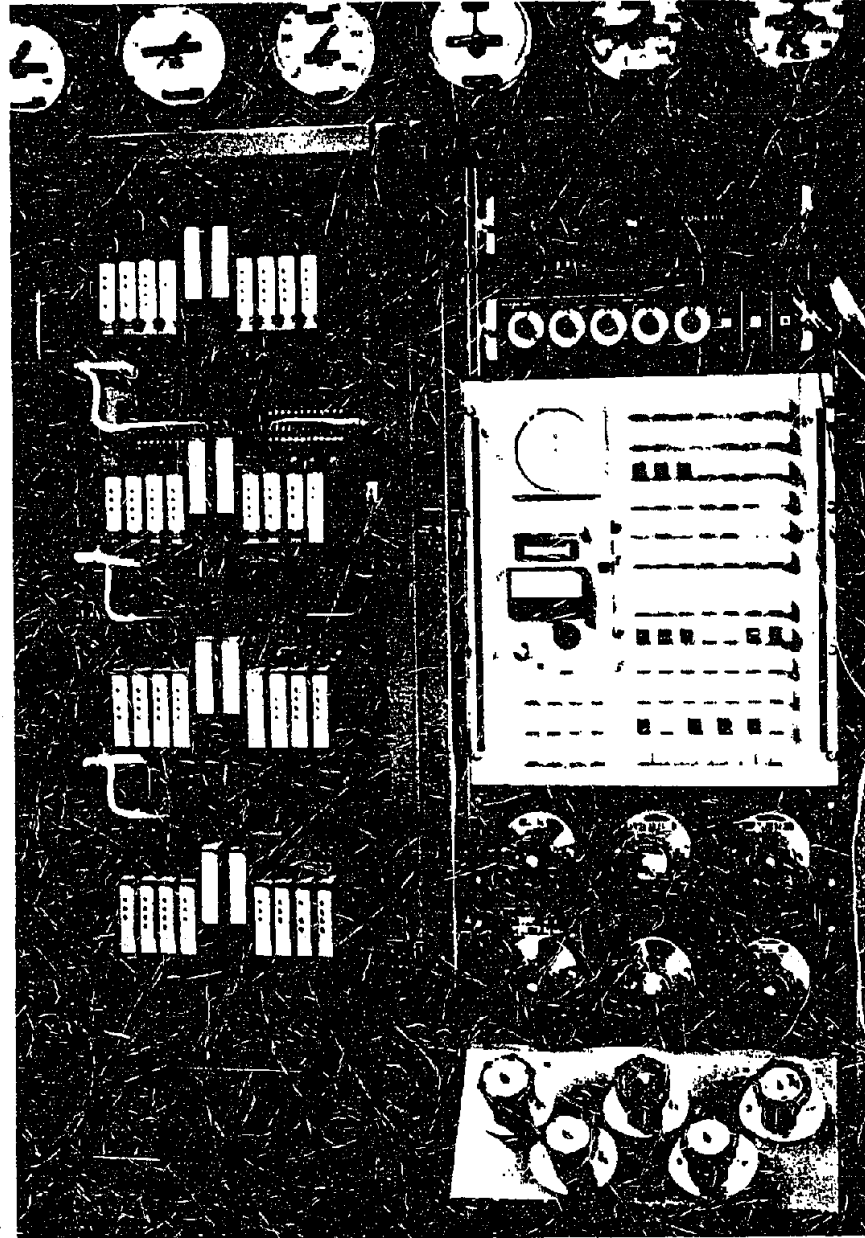


Figure 5.8-1 PDU Schematic

In order to facilitate the valve sequencing required during gasifier start-up and to monitor and execute numerous safety functions during gasification tests, a solid state, microprocessor based, programmable controller was integrated into the test console seen in Figure 5.8-2.

The controller continuously monitors the status of pressure switches, valve positions, command status, etc., and, dependent upon their status, makes decisions and executes PDU control. Pre-programmed start and shutdown sequences, stored in the memory of the controller, are used to control these operations.

The start program is initiated by the operator selecting first the ARM and then the FIRE switch on the control console. The automatic shutdown program is initiated should a potentially hazardous condition be detected by the programmable controller and requires no action by the operator. In the normal course of events, however, the pre-programmed shutdown sequence is initiated by the test operator simply closing the SHUTDOWN switch on the control console.



- PDU Start and Shutdown Sequence under Control of Programmable Logic Controller
- Critical Parameters Continuously Monitored throughout Test. In Event of Malfunction Appropriate Warning or Shutdown Action Taken

Figure 5.8-2. PDU Control Console with Integrated Programmable Logic Controller

A unique Bell designed device monitors coal flow to the reactor and, should there be an indication of coal flow stoppage, triggers the automatic shutdown program within fifty milliseconds.

Specific other parameters, monitored by the programmable controller and tied into the emergency shutdown logic are:

- Gasifier coolant water pressure
- Gas sample probe coolant water pressure
- Reactor chamber pressure
- Main gas trim valve closed

In addition, an out of tolerance condition in any of the following parameters results in audio and visual indications at the test console:

- Quench water pressure
- Quench section cooling water pressure
- Condenser cooling water pressure

Other key operating parameters visually monitored in the instrument room are reactor pressure, reactor temperatures, and reactant flowrates. Should a parameter deviate from its intended value by a pre-specified amount, appropriate corrective action is initiated and, in an extreme case, gasifier shutdown can be directly initiated from the instrumentation room.

All test operations are conducted by experienced cell technicians under the cognizance of either a test engineer or a supervisor. In addition, pre-test, and post-test operations are conducted in accordance with written procedures. These procedures are approved by a committee of test engineers and the technical director and are updated promptly as required.

Prior to each gasification test, the reactor and downstream system is pressure tested to the nominal operating pressure. In addition, sequence tests are run periodically to demonstrate proper valve operation.

5.9 PDU CHECKOUT TESTS

Upon completion of PDU construction, the following checkout tests were performed:

- Coal flow tests
- Start sequence development tests
- Gasification checkout tests

5.9.1 Coal Flow Tests

Gasifier and facility modifications resulted in the coal injector being ten feet higher (relative to the coal feed tank outlet) than during previous gasification testing. It was necessary, therefore, to conduct coal flow tests to establish feed system pressure drop versus flow rate relationships for the new configuration.

The new feed line configuration was simulated by connecting the coal injector end of the one-half-inch diameter coal feed line to a two-inch diameter tube which was in turn connected to the coal load tank as shown in Figure 5.9-1.

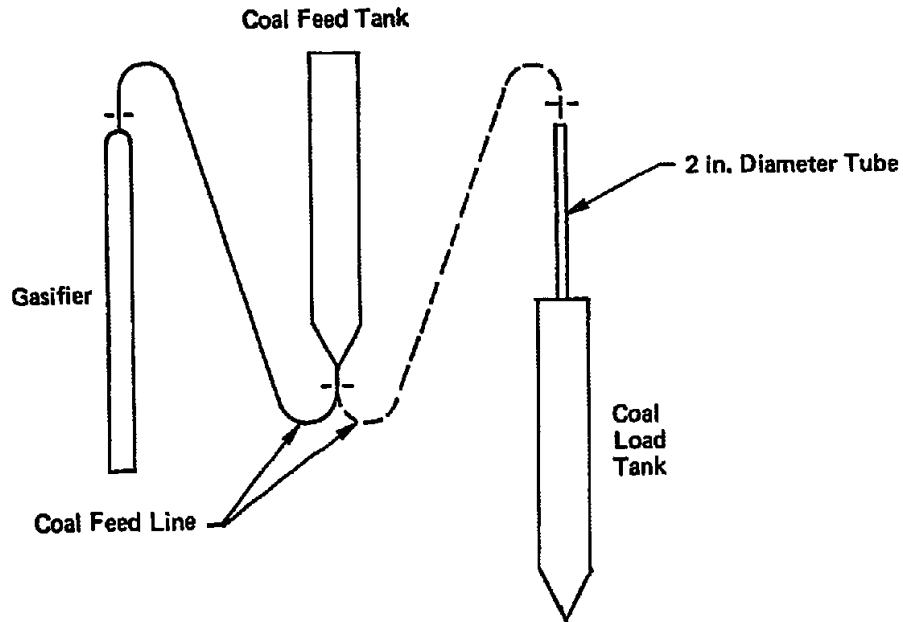


Figure 5.9-1 Coal Flow Test Installation

The coal load tank was pressurized to 220 psia, to simulate reactor operation; the coal feed tank was pressurized to a range of potential operating pressures. Six flow tests were successfully performed over a coal flowrate range of 0.22 to 0.37 lb/sec. (See Figure 5.9-2.)

Pressure drop versus flow relationships for coal line orifices were virtually unchanged from those experienced during previous test programs. The overall line pressure drop was, however, approximately 9 psi higher than during previous test programs. The increase is attributed to the increased coal lift height of ten feet and the additional coal feed line length.

5.9.2 Start Sequence Development Tests

The basic start sequence selected for the PDU is shown in Figure 5.9-3 and outlined in the following:

- The gasifier and PDU equipment down to the main gas trim valve and bypass valve are pressurized with nitrogen to 220 psia prior to a gasification test (reference Figure 5.8-1). This facilitates a pressure test prior to every gasification run.
- The main gas trim valve is partially opened to vent the gasifier pressure.
- When the pressure reaches a pre-determined level, a pressure switch is actuated which fires a solid grain starter located in the gasifier head (reference section 5.3.4). The hot gases from the starter raise the gasifier pressure and create the high temperature conditions required to initiate coal/oxygen reactions.

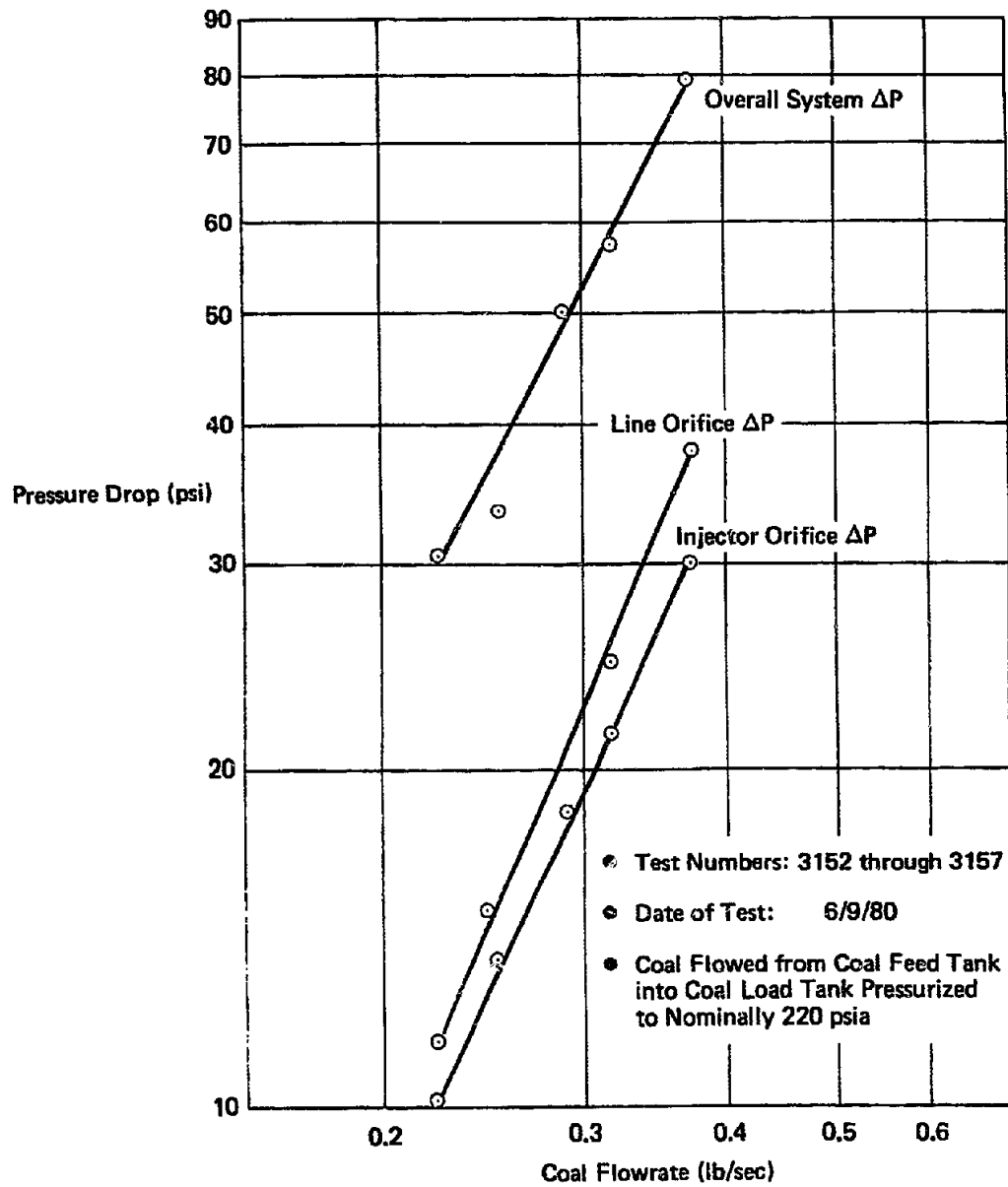


Figure 5.9-2 Coal Feed System Pressure Drop versus Coal Flowrate

- Oxygen is admitted to the gasifier followed by coal and steam and gasification reactions are initiated.
- The starter grain burns for approximately 1.5 seconds and, to assure that gasification reactions are fully initiated, a second grain is fired to provide an effective burn time of 3.0 seconds.
- During the period of gasification initiation the gasifier pressure increases to the steady state run level.

The following series of tests were conducted to establish the necessary data to define appropriate pressure switch level setting, events timing and control valve settings to effect a safe and successful start:

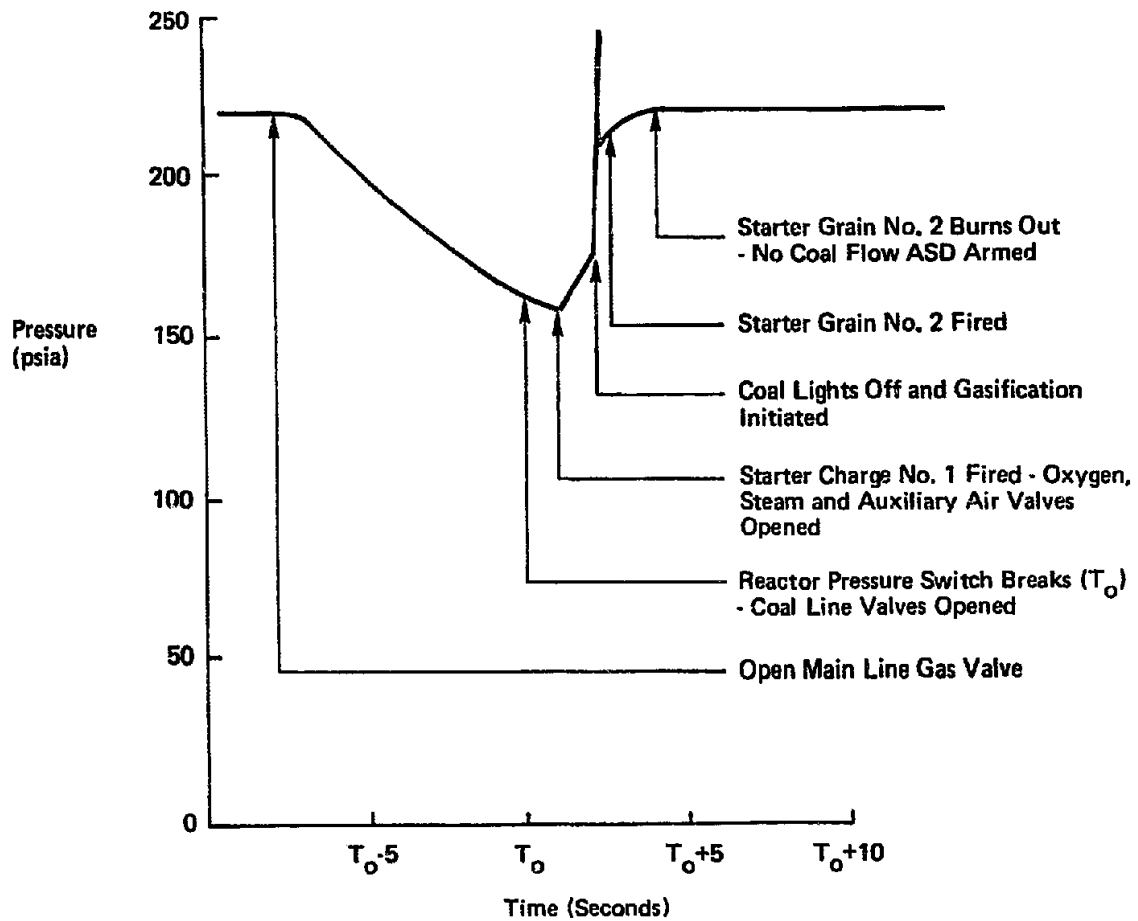


Figure 5.9-3 PDU Start Sequence

- Gasifier ventdown tests
- Starter grain fire test
- Starter grain fire test with oxygen addition
- Coal flow tests to establish time from coal valve command to coal reaching gasifier.
- Gasification initiation tests (reference section 5.9.3).

The gasification start sequence resulting from the above is as follows:

- Pressurize gasifier with nitrogen to 220 psia
- Open main gas trim valve to 20% position – gasifier pressure vents.
- T_0 Pressure switch actuated at a gasifier pressure of 168 psia
- T_0 Open coal line valve
- $T_0 + 1$ sec. Fire starter grain No. 1
Open oxygen supply valve
Open steam supply valve
Open auxiliary air valve (accelerates coal)

- $T_0 + 2.5$ sec. Fire starter grain No. 2
- $T_0 + 6$ sec. Initiate quench water flow

The developed start sequence resulted in safe and repeatable gasifier starts as recorded in Figure 5.9-4.

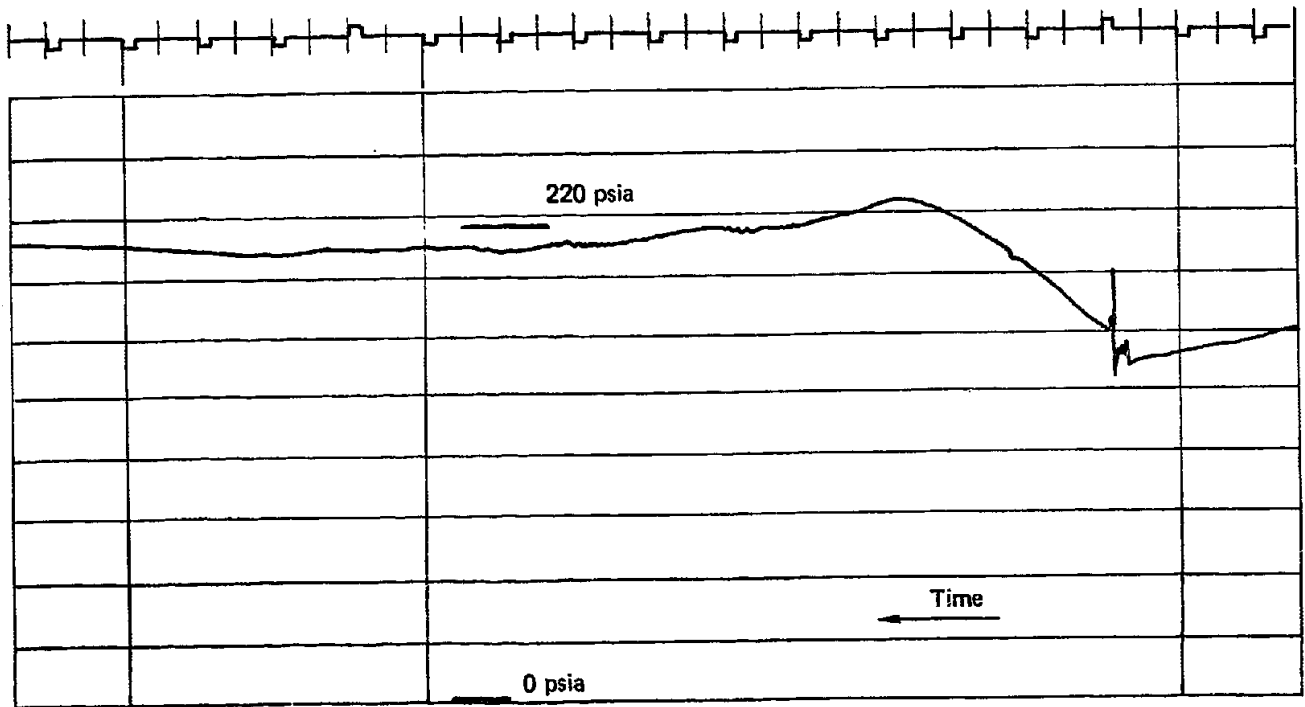


Figure 5.9-4 Reactor Pressure Trace for Typical Gasifier Startup

5.9.3 Gasification Checkout Tests

Three checkout gasification tests were performed, during July 1980, to establish procedures for PDU operation. Several startup problems were encountered and rectified. Successful sustained gasifier operation was obtained during subsequent testing (Figure 5.9-5) conducted under Bell funding. This latter work is reported in Section 6.

5.9.3.1 Gasification Checkout Test No. 3193 – The gasification process was initiated satisfactorily; however, after the second starter grain was expended and the quench water flow initiated, the gasifier pressure decayed steadily. Eleven seconds into the test the pressure had fallen to 168 psia, the low pressure pressure switch was actuated and the programmable logic controller correctly executed the emergency shutdown procedure.

Analysis of test results indicated that the pressure decay was the combined result of too little flow impedance in the main gas trim valve/fixed orifice assembly and the transition from nitrogen pressurant gas to reactor product gas. The decay was not the result of any degradation in gasifier performance. The decision was made, therefore, to further close the main gas trim valve for the next test and to further close the valve following burnout of the starter grain.

Detailed analysis of gasifier shutdown data showed that the shutdown sequence and safety monitoring circuits were operating satisfactorily.

Test No.	Date	Duration	Test Results	Action Required for Next Test
3193	7/9/80	11 sec	<ul style="list-style-type: none"> ● Gasification Initiated Satisfactorily ● Reaction and Facility Operated Safely ● Reaction Pressure Decayed to 168 psia due to Gas Line Trim Valve being too Far Open - ASD Shutdown ● Low Reactor Pressure ASD Demonstrated ● No Coal Flow ASD Demonstrated during Shutdown 	<ul style="list-style-type: none"> ● Set Gas Line Trim Valve for Higher Pressure Drop during Start - Adjust as Necessary during Run
3194	7/10/80	9 sec	<ul style="list-style-type: none"> ● During Firing of Second Starter Charge Bellows between Starter and Reactor Failed - Reactor Shutdown. - Secondary Damage Negligible 	<ul style="list-style-type: none"> ● Restrain Reactor Head to Prevent Lateral Accelerations during Start Up ● Stiffen Starter Assembly Mounting Bracket to Eliminate Bending Loads on Bellows
3195	7/23/80	30 sec	<ul style="list-style-type: none"> ● Gasification Initiated ● Modifications to Resolve Starter Bellows Problem Successful ● Reactor Pressure was being Increased by Gas Line Trim Valve when Inaccurate "Valve Closed" Microswitch Made and Reactor was Shutdown by ASD 	<ul style="list-style-type: none"> ● Install Smaller Dia Fixed Orifice in Gas Line in Order to Operate Trim Valve Further Open ● Decrease Quench Water Flowrate - Overquenching <p>ASD-Automatic Shutdown Device</p>

Figure 5.9-5 Summary of Gasification Checkout Tests

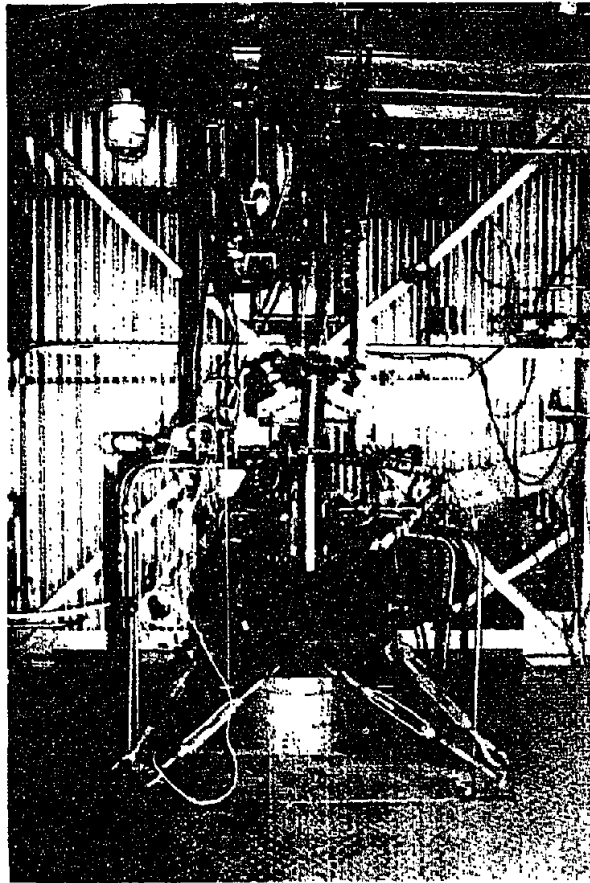
5.9.3.2 Gasification Checkout Test No. 3194 – This test was a virtual repeat of the previous test except that in this case when the pressure decayed, the low pressure switch was made after nine seconds rather than eleven seconds. The more rapid vent was unexpected since the main gas trim valve was closed further than for test No. 3193. The anomaly was explained, however, when post-test inspection of the gasifier revealed a rupture in the bellows, between the twin starter cases and the reactor head. The rupture presented an additional gas vent path which resulted in the faster ventdown. Secondary damage, as a result of the bellows failure, consisted only of minor cable scorching.

Analysis indicated that the starter mount bracket was not stiff enough to prevent excessive bending moments being applied to the starter bellows assembly during gasifier start up. It was further identified that lateral gasifier movement could be induced due to the fact that the reactor head was not rigidly tied to the test stand.

To rectify the situation, brackets and twin buckles were installed to tie the reactor head to the test stand and a stiffer starter mounting bracket was installed (Figure 5.9-6).

5.9.3.3 Gasification Checkout Test No. 3195 – Following successful gasification initiation, the characteristic slow dropoff in chamber pressure occurred as the gas flowing through the main gas valve/fixed orifice assembly transitioned from nitrogen to product gas. The main gas valve setting was in the process of being reduced and the reactor pressure was recovering when, at 30 seconds, the gasifier was shut down by an automatic shutdown monitoring circuit. The events monitor indicated that the cause of shutdown was the Valve Closed microswitch of the main gas valve

which erroneously indicated valve closure. Further investigation indicated that the microswitch setting was very sensitive as the valve approached closure. To enable the valve to be run further open during the tests, the diameter of the fixed main gas line orifice was reduced.



- Stiffer Starter Mounting Bracket
- Gasifier Head Tied to Test Stand to Eliminate Lateral Accelerations during Start Up

Figure 5.9-6.
Gasifier Head End Installation

5.9.4 Test Curtailment

Due to a shortage of funds, no further gasification tests were completed under this program (reference Section 6.0). Subsequently, however, seven gasification tests were completed under Bell sponsorship. During each of these tests gasifier initiation, operation and shutdown was satisfactory.

5.10 SECONDARY COAL FLOW SPLITTING AND INJECTION

The objective of the secondary coal injection test program was to develop an injection system for use during the final series of gasification tests.

Secondary coal injection concepts were analyzed and evaluated using a coal particle trajectory model and prior gasifier test experience. Evaluation criteria were:

- Coal Mixing
- Uniform Coal Distribution
- No Injector Plugging or Deleterious Slag Accumulation

Two design concepts were selected, fabricated and subjected to cold flow test evaluation. Both design concepts utilized four secondary coal injection ports. Coal flow splitting and secondary coal injection tests were successfully completed in a coal flow test facility fabricated at Bell, with the assistance of the New York State ERDA.

5.10.1 Analysis and Design of Secondary Coal Injection System

It was desired to inject nominally 0.1 lb/sec of pulverized secondary coal into a five inch diameter gasifier operating at a pressure of 220 psia. The molecular weight of the gas produced upstream of coal injection was assumed to be 21.49 and a secondary coal transportation gas of $3 \text{ H}_2 + \text{CO}$ was assumed.

5.10.1.1 Coal Distribution – The basic approach used to examine the various possible injection schemes involved the calculation of mean trajectories for a variety of coal particle sizes assumed to enter into the primary gas stream at points along the reactor periphery. (See Figure 5.10-1.)

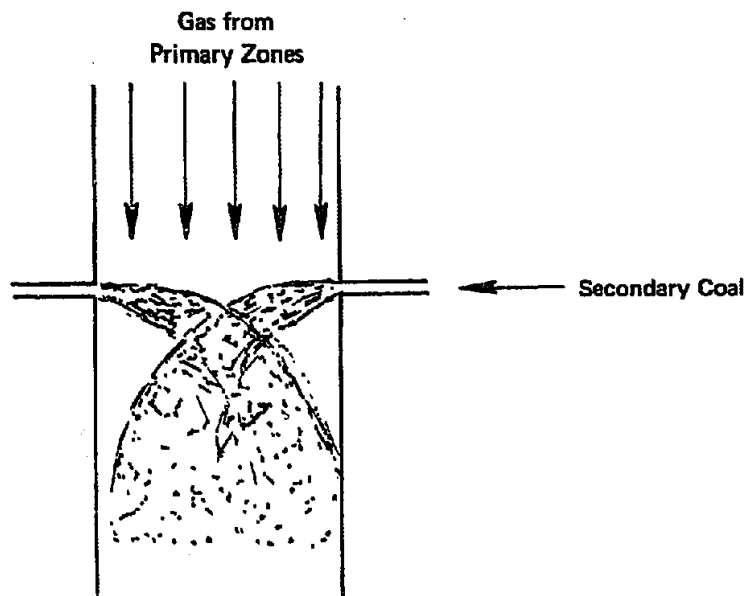


Figure 5.10-1. Basic Secondary Coal Injection Scheme

The coal particle size distribution used for these analyses were based upon measured values for coal used at Bell (Figure 5.10-2).

Injection velocity was the principal independent variable. Injection angle was maintained at 90° to the main gas flow. Although angle variations would not be expected to add much to mass flux distribution from the standpoint of particle trajectories, there could be some impact on turbulent diffusion, particularly with upstream injection. The technique used takes the particle trajectory information and converts it into radial mass flux distributions. It includes the effects of opposed jet mixing when more than one injection point are used. No circumferential mixing due to turbulent diffusion (jet spreading) was calculated. Possible effects from downstream recirculation zones were also not considered. Integrated mass flowrate as a function of flow area as one moves radially outward from the reactor centerline are shown for injection velocities of 35 fps, 70 fps and 100 fps (Figures 5.10-3 through 5.10-5).

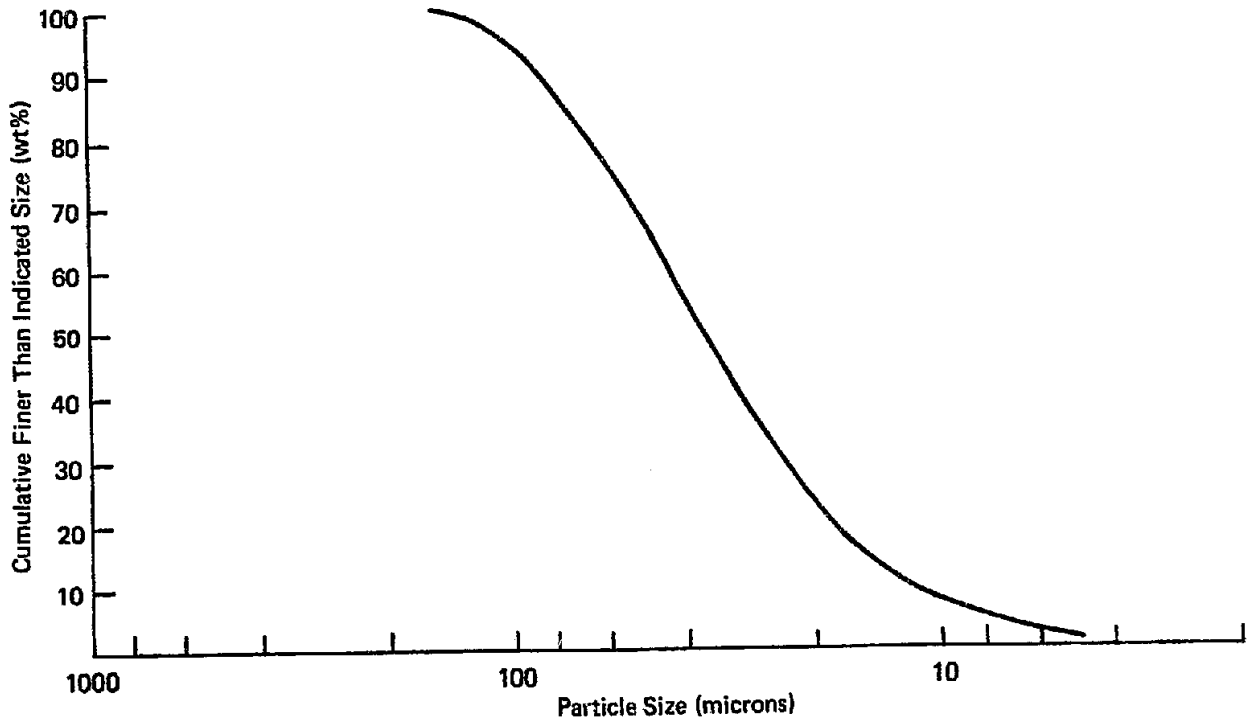


Figure 5.10-2. Coal Particle Size Distribution

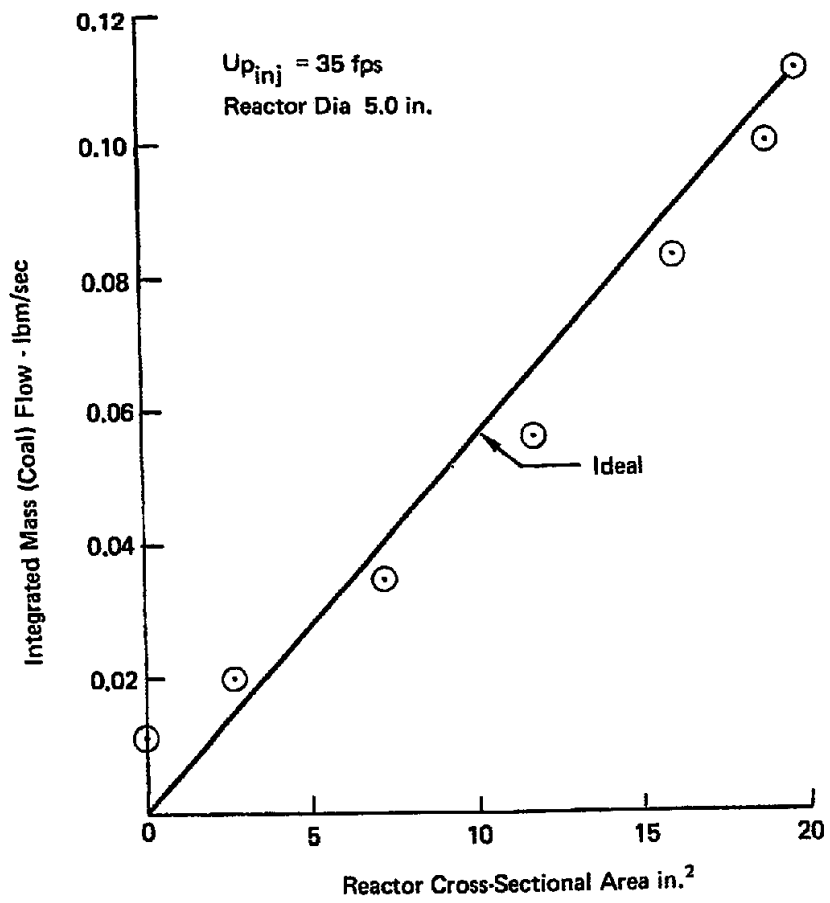


Figure 5.10-3. Integrated Mass Flowrate for Coal Injection Velocity of 35 Feet per Second

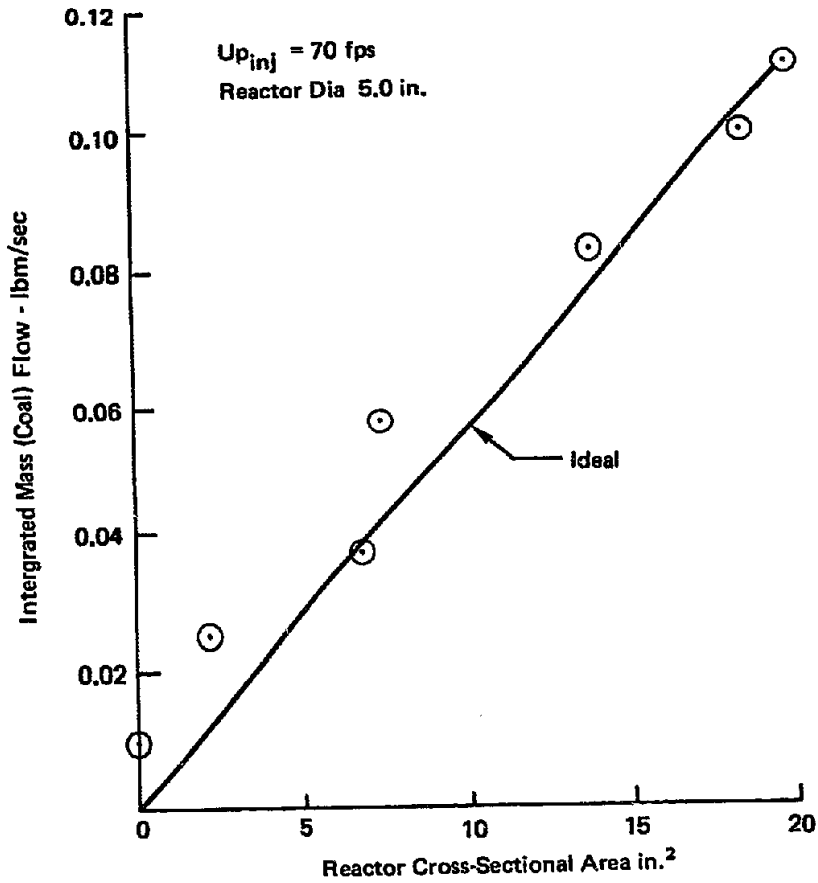


Figure 5.10-4. Integrated Mass Flowrate for Coal Injection Velocity of 70 Feet per Second

In each case, a symmetric injection scheme involving more than one peripheral injection point was assumed. It is desirable for the results to plot as a straight line in which case the mass flux or flow per unit area is constant. Under these conditions the coal mass is distributed in a uniform manner across the reactor cross section. It is apparent from Figures 5.10-3 through 5.10-5 that a relatively constant mass flux can be achieved over a relatively wide range of injection velocities using a symmetric multiple port injection scheme, although the lower and higher velocity curves seem to deviate somewhat less from linearity than does the 70 fps injection case. The 100 fps case achieves reasonable uniformity by mixing particles from opposing wall jets. At 35 fps particles from a given port do not cross the centerline (except of course by turbulent mixing).

5.10.1.2 Number of Injection Ports – Given a range of acceptable injection velocities, selection of the number of injection ports depends in part on being able to deliver the fluidized coal without incurring saltation problems. Minimizing carrier gas flows must also be a consideration. It can be shown that any reasonable injection scheme will require particle transport to be in the dilute (as opposed to dense) phase where loading ratios (lbm coal/lbm gas) are of the order of unity. With the exception of flow through contractions or expansions, particle velocities in such cases can be assumed to be approximately equal to gas velocities. Applying the method of Zenz (Ref. 5.10.1) to the present situation results in the following equation for saltation velocity:

$$U_{cs} = \frac{U_{scm} (D_t^{0.4})}{1.442} \left[\frac{23.07}{N D_t^2} + 1 \right] \sim (\text{fps}) \quad \text{Eq. 5.10.A}$$

where:

D_t = tube diameter (in.)

U_{scm} = single particle saltation velocity (fps)

(U_{scm} is dependent upon carrier gas density and velocity and particle size range. For the proposed coal/gas mixture, this value is 4.06 fps).

N = number of injection ports

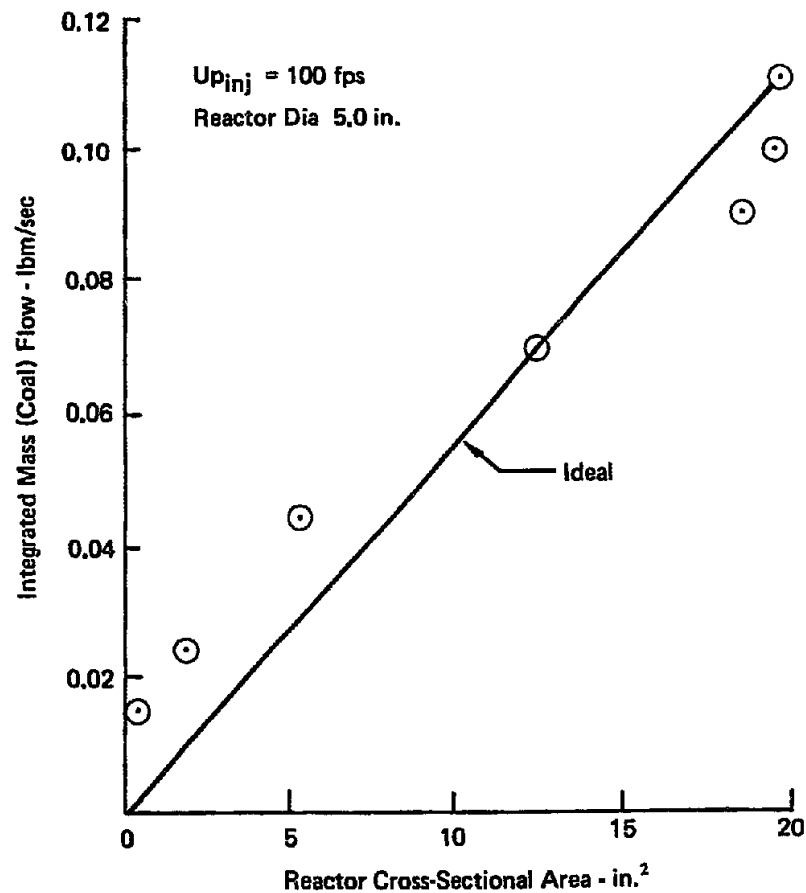


Figure 5.10-5. Integrated Mass Flowrate for Coal Injection Velocity of 100 Feet per Second

Equation 5.10.A gives the lowest velocity allowed to transport the desired coal flow (0.111 lbm/sec) through N equal sized tubes without incurring saltation problems. It can, therefore, be used to find the smallest diameter tube capable of delivering the coal at any desired velocity by simply setting $U_{cs} = U_{pinj}$, the particle injection velocity. Results for 35 fps and 100 fps and various injection points (N) are tabulated in Figure 5.10-6.

It can be shown that the tabulated gas flows are the minimum achievable for a prescribed injection velocity. It will be noted however, that increasing allowable injection velocities results in

Desired Injector Velocity (fps)	N	Required Tube Dia ² - in.	Required Gas Flow ² (lbm/sec)
35	2	1.00	0.143
	3	0.77	0.127
	4	0.65	0.120
	6	0.50	0.107
100	2	0.50	0.103
	3	0.39	0.093
	4	0.32	0.086
	6	0.25	0.077

Figure 5.10-6. Secondary Coal Flow System Design Options

a decrease in required flow which can be understood by referring to Equation 5.10.A. In general, the term $(23.07/N D_t^2) \gg 1$ so that U_{CS} varies inversely as the 1.6 power of tube diameter. Tube area however, varies as the square of diameter and the result is a net decrease in volume flow. Since mass flux distributions are comparable at 100 fps and 35 fps, it would appear reasonable to favor the higher injection velocities. Higher injection speeds may also be less affected by char and slag particles which will be entrained in the primary zone product gas.

The selected approach involved four opposed wall jets of 0.32 in. diameter with injection velocities at 100 fps. This scheme gives reasonable circumferential and radial mass distribution with relatively low fluidizing gas flow requirements.

Two variants of the four port injection scheme were recommended for test evaluation. The first scheme utilizes radial injection from two pairs of diametrically opposed injection ports. For the second scheme, the injection ports are rotated by 20° to improve circumferential distribution without appreciably changing radial distribution as shown in Figure 5.10-7.

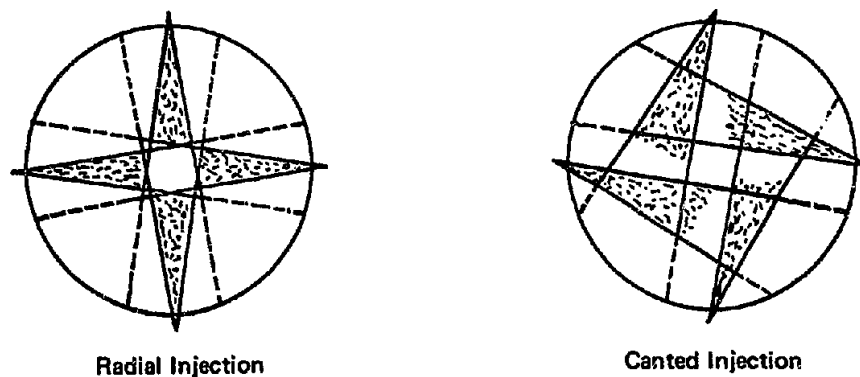


Figure 5.10-7. Four Port Secondary Coal Injection Schemes

5.10.1.3 Secondary Coal Injection System (Figure 5.10-8) – Primary elements of the secondary coal injection system are:

- Coal Feed Tank – from which pulverized coal is fed in dense phase (97% by weight coal to 3% by weight nitrogen gas).
- Four Way Coal Splitter – in which dense phase coal flow is split into four equal streams and a gas mixture of 3 H₂ + CO is added to accelerate coal particles.

- Four Secondary Coal Injectors – each of which inject one quarter of the secondary coal flow at an injection velocity of nominally 100 fps. The injectors are inserted and locked in the secondary coal injector ring and their depth of penetration into the gasifier is adjustable.

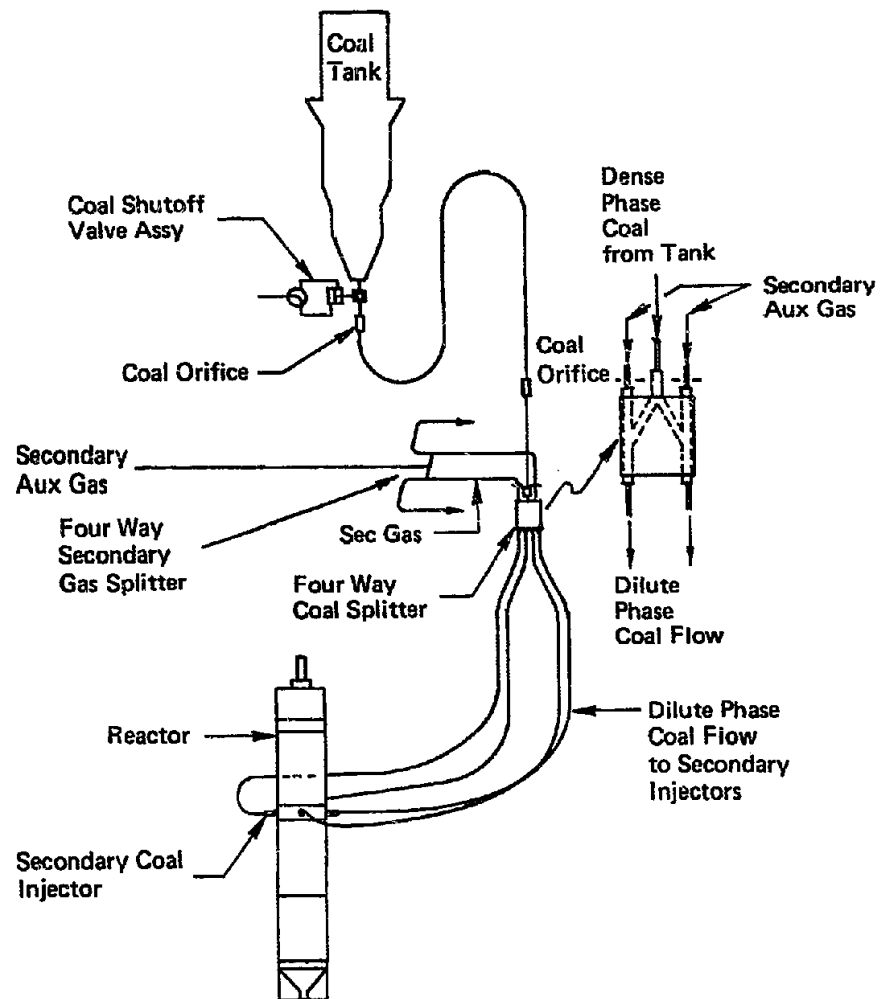


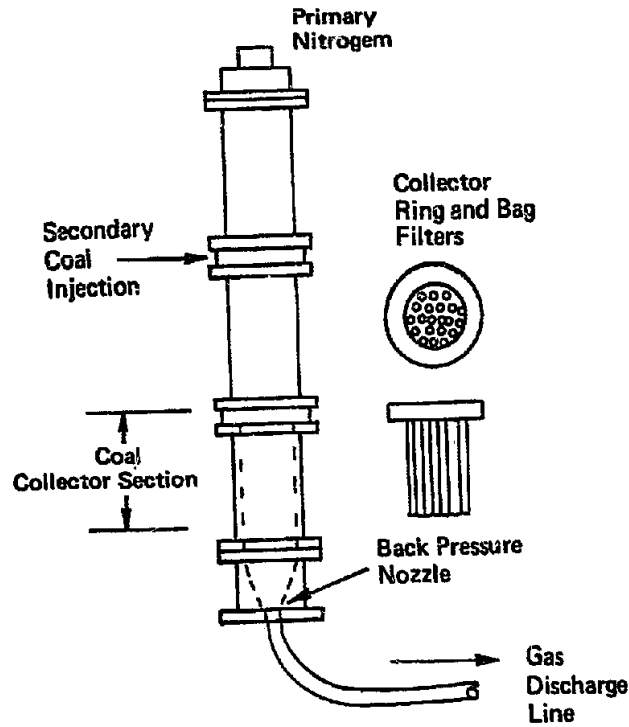
Figure 5.10-8. Secondary Coal Injection System

5.10.2 Cold Flow Simulation Tests

Cold flow tests were conducted to develop the secondary coal injection system prior to installation and use in the HMF gasifier. A one-half ton per hour HMF gasifier used during previous gasification test programs was adapted to accept secondary coal injection. (See Figure 5.10-9.) Nitrogen gas was used to simulate the primary gas flow and a nineteen element coal collection filter system was used to assess coal distribution.

5.10.2.1 Definition of Cold Flow Test Conditions – A ground rule for the cold flow tests was:

- Secondary coal flowrates and coal injection velocities should be those to be used during gasification tests.



- Full Scale ½ ton/hour Reactor Installed in the Dense Phase Flow Test Facility
- Nitrogen Gas Injected at the Head to Simulate Primary Reactor Flow
- Secondary Coal Injected Downstream of Mixing Section, and Collected in 19 Bag Filters Uniformly Distributed across the Reactor
- Test Reactor Operates at Pressure
- Test Duration Nominally Twenty Seconds
- Bag Filter Contents Individually Weighed to Assess Coal Distribution

Figure 5.10-9. Secondary Coal Distribution Test Setup

The problem was, therefore, to define primary nitrogen flowrates and pressures to best simulate hot gasification conditions. Insight into the problem can be obtained by examining the related equations of particle motion:

$$\frac{dU_p}{dt} = \left(\frac{0.75 \mu_g}{\rho_p d_p} \right) C_d R_e (U_g - U_p) \quad \text{Eq. 5.10.B}$$

$$\frac{dV_p}{dt} = \left(\frac{0.75 \mu_g}{\rho_p d_p} \right) C_d R_e V_p \quad \text{Eq. 5.10.C}$$

$$R_e = \frac{[(U_g - U_p)^2 + V_p^2]^{1/2} d_p \rho_g}{\mu_g} \quad \text{Eq. 5.10.D}$$

$$C_d \cong \left(\frac{24}{R_e} \right) \left[1 + \frac{R_e^{2/3}}{6} \right] \quad \text{Eq. 5.10.E}$$

C_d = Drag Coefficient

V_p = Particle Velocity (radial)

d_p = Particle Diameter

μ_g = Gas Velocity

R_e = Particle Reynold's Number

ρ_g = Gas Density

U_g = Gas Velocity

ρ_p = Particle Density

U_p = Particle Velocity (axial)

Dynamic similarity requires that the coefficients in these equations be the same at all times for both the prototype and model. In general this is not possible. In the present case, the viscosity of the cold gas will be less than half that of the combustion products. Injection Reynolds numbers could be set equal by adjusting gas density (pressure) but the large difference in viscosities will still influence Eq. 5.10.B and Eq. 5.10.C. Combination of Eq. 5.10.C through Eq. 5.10.E shows that for a constant U_g and for the same particle size and density dynamic similarity can be achieved if the product $C_d \rho_g$ can be held constant throughout the motion. Because of the monotonic nature of the drag function the C_d 's applicable in one fluid will generally be larger (or smaller) than in another throughout the particle motion although the constancy of that ratio is in no way evident. Nonetheless it was decided to perform several trajectory calculations with the nitrogen at reduced pressures to determine how closely individual motions could be simulated. Results, in terms of integrated mass flow distributions, are presented for 35 fps and 100 fps injection velocities in Figures 5.10-10 and 5.10-11, respectively.

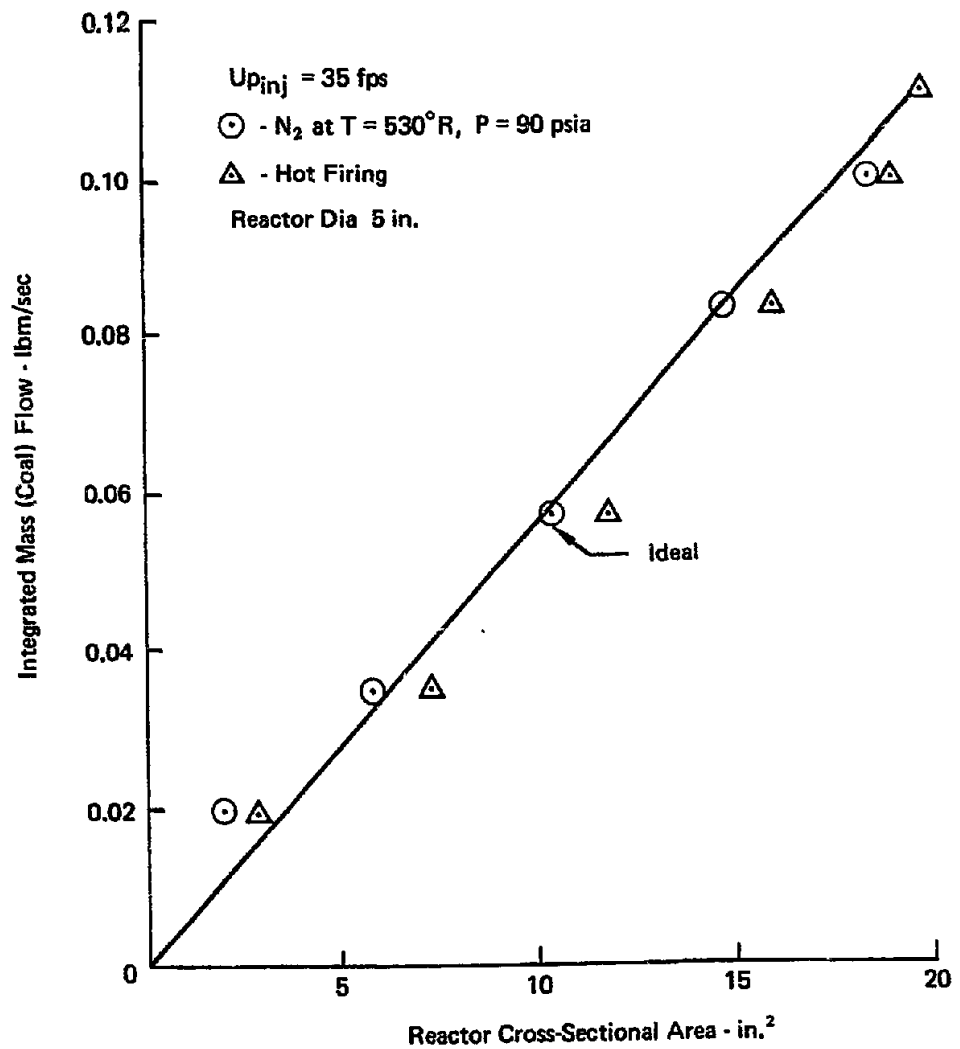


Figure 5.10-10 Integrated Mass Flowrate for Coal Injection Velocity of 35 Feet per Second and a Reactor Nitrogen Pressure of 90 psia

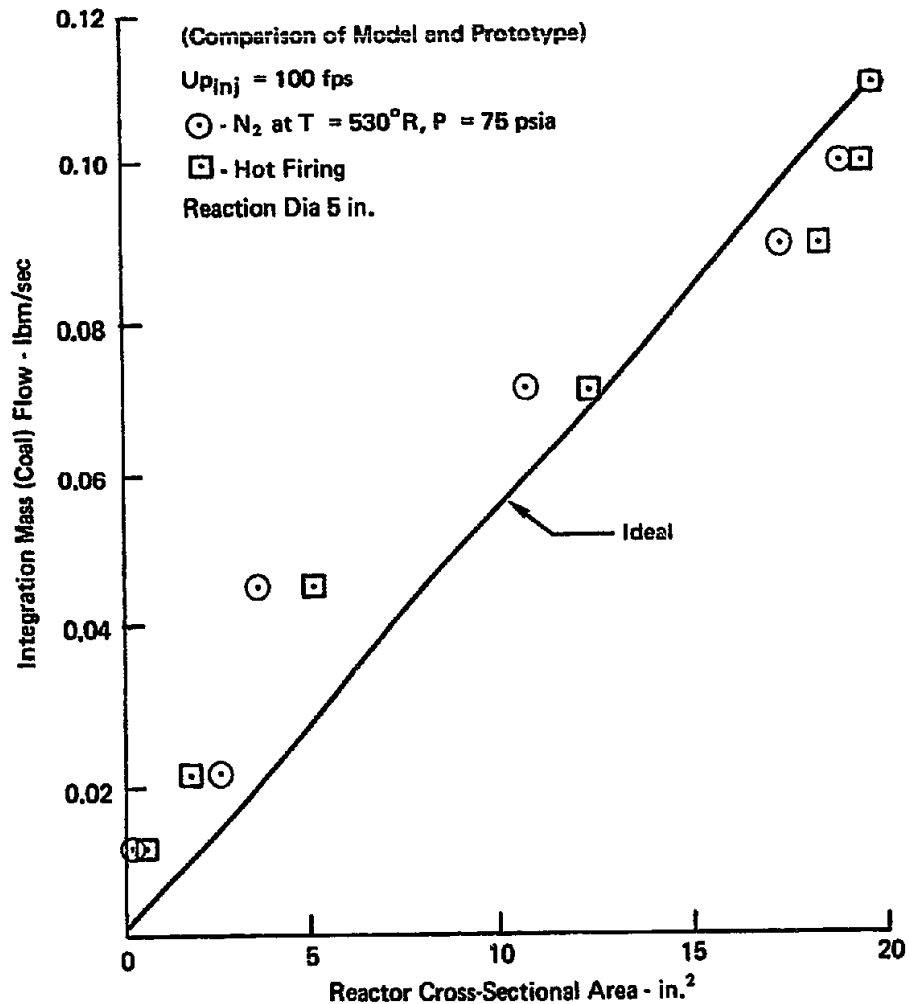


Figure 5.10-11 Integrated Mass Flowrate for Coal Injection Velocity of 100 Feet per Second and a Reactor Nitrogen Pressure of 75 psia

Use of N_2 at about 90 psia gave simulated results very similar to an actual firing with coal injection at 35 fps. Reduction of the pressure to about 75 psia resulted in a reasonable simulation of the 100 fps hot fire case. It was therefore recommended that the simulation be conducted as follows:

- I. Simulate the flow of primary gas with room temperature nitrogen at a reduced pressure (75-90 psia depending on desired injection velocity) and at velocities equal to combustion gas velocities (30.25 fps in the 5.0 in. reactor). This requires a mass flow of nitrogen of approximately 1.8 lbm/sec.
- II. Inject the secondary coal at the same velocity selected for prototype operation using nitrogen at reduced pressure (75-90 psia) as the carrier gas. At 100 fps injection this will require about 0.1 lbm/sec nitrogen. Calculations for nitrogen at these pressures show saltation velocities well below those for the H_2/CO mixture so that delivery of the coal at the desired rates and velocities should not be a problem during cold flow testing.

III. The collection plan should be located no less than two reactor diameters downstream of injection. Calculations indicated that most of the particle penetration takes place within this distance.

5.10.2.2 Cold Flow Tests – A one-half ton per hour HMF gasifier, used during previous HMF gasifiers test programs, was installed in the K-2 test facility. The gasifier was adapted to accept a secondary coal injector ring similar to the one to be used with the DOE/GRI oxygen-blown gasifier (Figure 5.10-12). Feed lines, coal flow control orifices, a 4-way coal splitter, accelerating gas orifices and flow lines to the injector were installed and were consistent with line lengths and component locations to be used in the gasification test cell. These tests would thus provide flow calibration of the entire secondary coal flow installation prior to gasification testing.

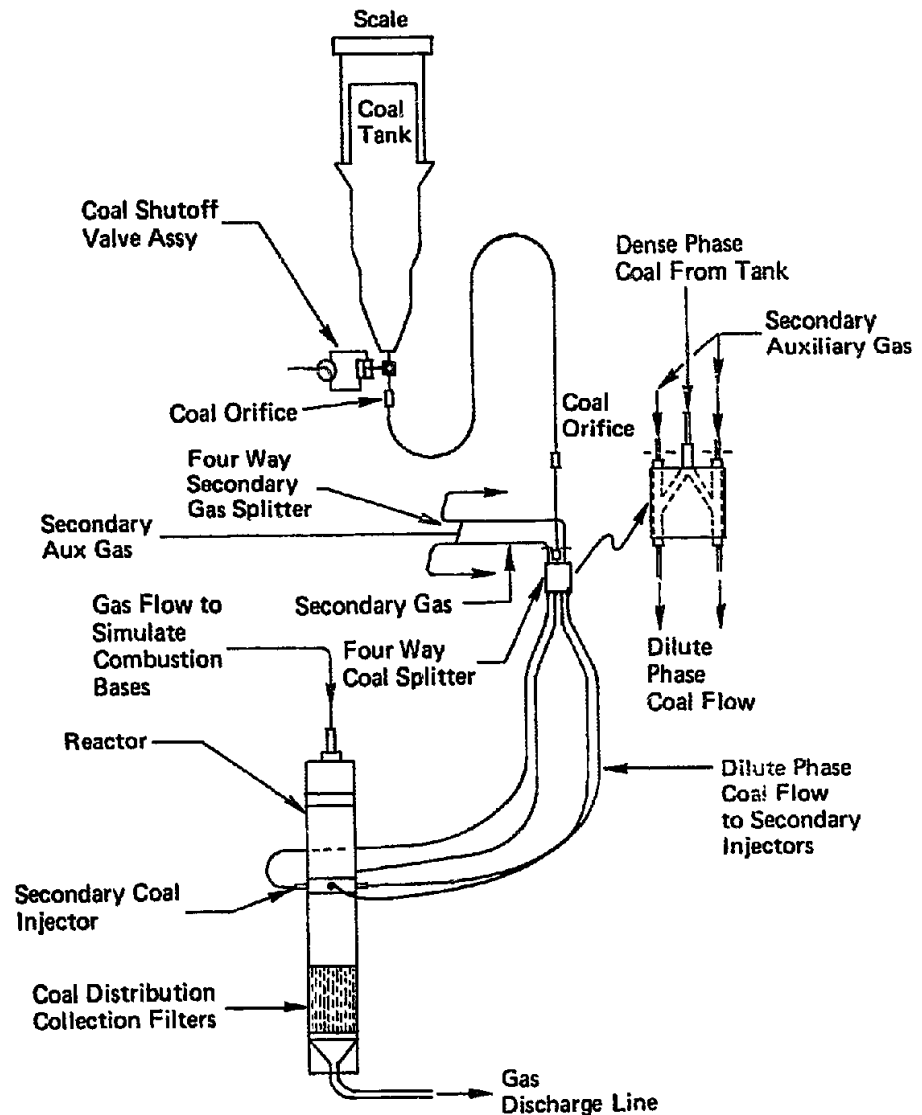


Figure 5.10-12. Secondary Coal Injection Cold Flow Test Facility

Coal was fed to the 4-way splitter (Figure 5.10-13) in dense phase. Downstream of the splitter, nitrogen was injected into each of the four coal feed lines to achieve the desired coal particle injection velocity.

Nitrogen gas was injected into the head of the gasifier to simulate the downflow of primary zone product gas (Figure 5.10-14).

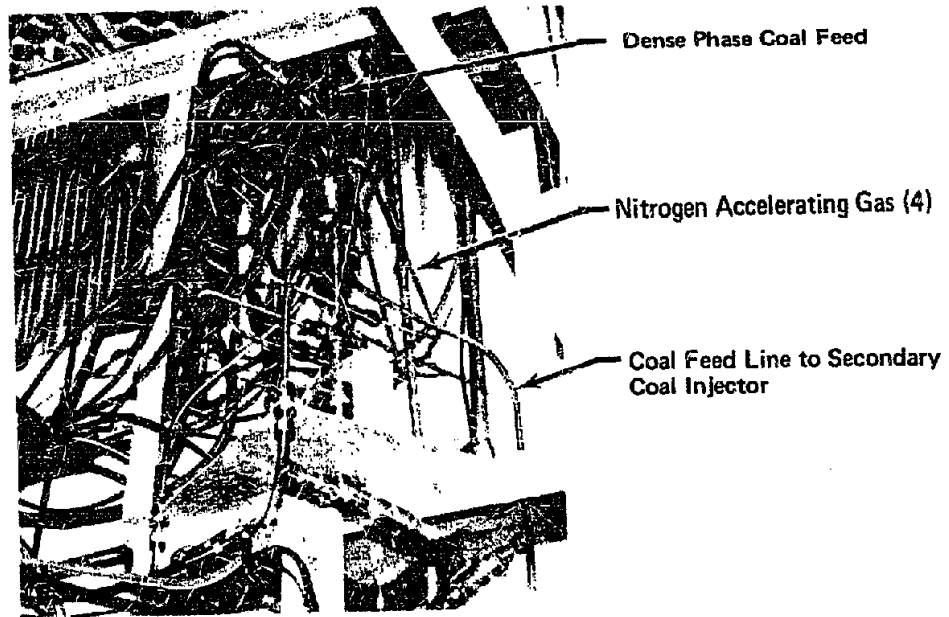
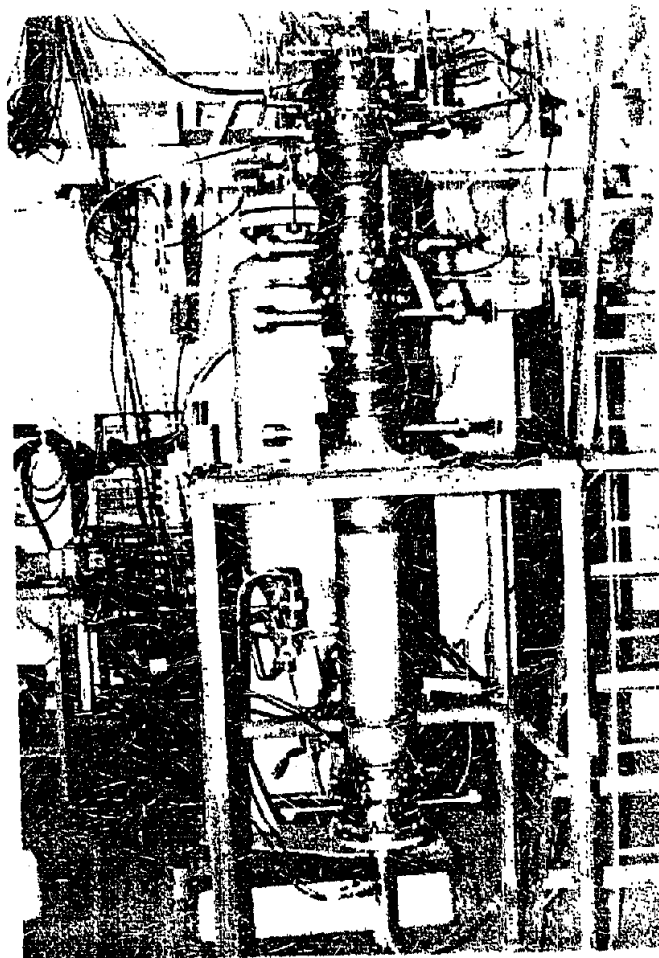


Figure 5.10-13. Four Way Coal Splitter Installation



- Nitrogen Gas Injection
- Secondary Coal Injection
- Mixing Section
- Flow Splitter
- Coal Filters
- Gas Discharge Line

Figure 5.10-14.
Gasifier Installed in Cold Flow Facility

A coal collection chamber section was installed at the bottom of the reactor and was separated from the coal injector by a mixing section internal to the collecting chamber; there were 19 thimble filters mounted in a collector ring (Figure 5.10-15). Coal distribution was determined by weighing the coal collected in each of the 19 filters (Figure 5.10-16).

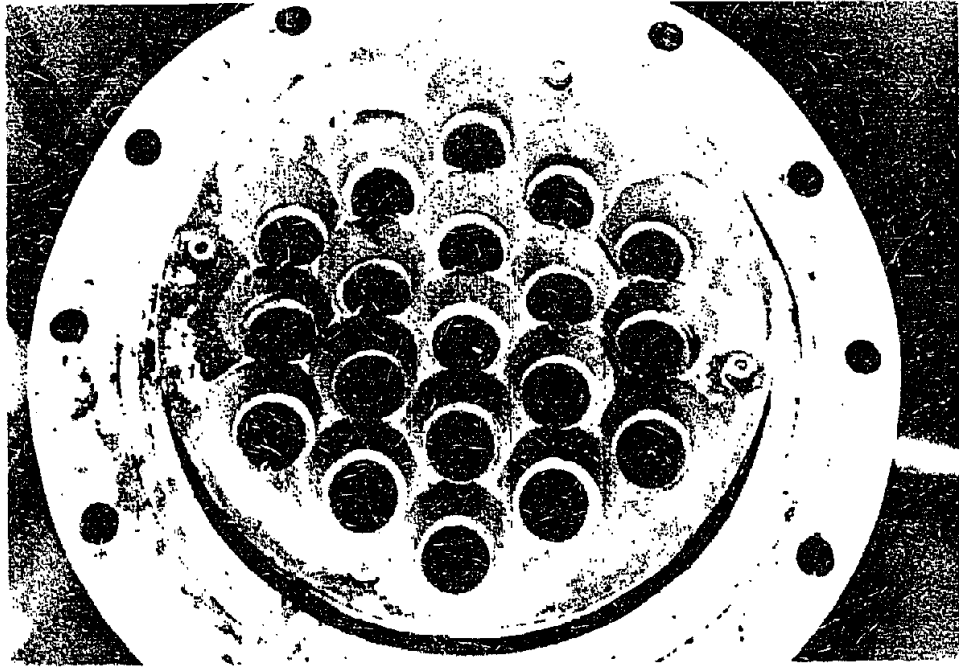
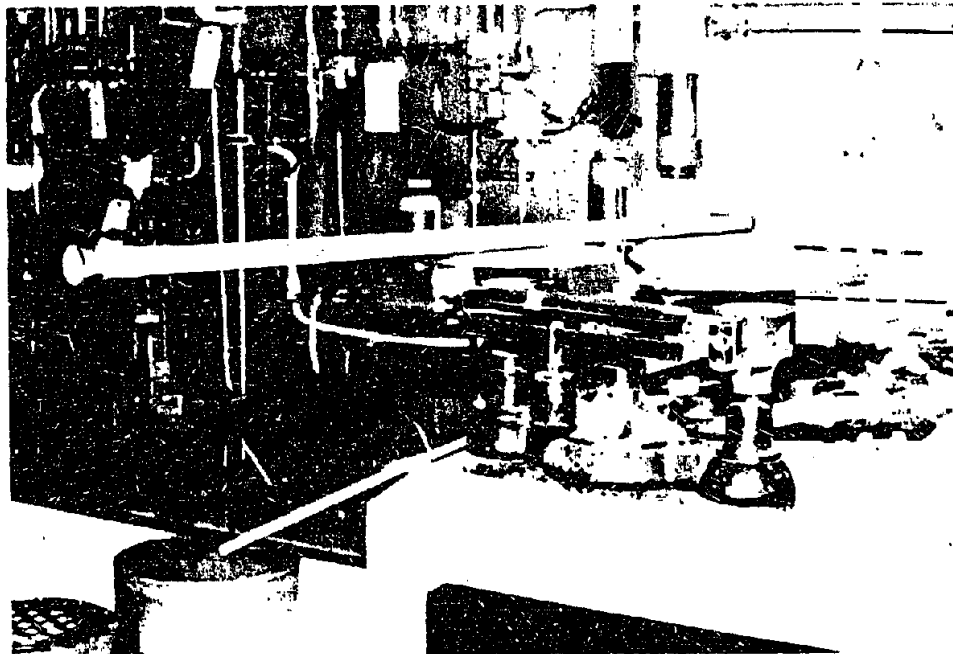


Figure 5.10-15. Flow Splitter at Entry to Coal Collector Filters



- Each Filter Weighed Before and After Test to Determine Coal Collected

Figure 5.10-16. Coal Collection Filter

During initial tests four way splitting could not be achieved. Coal would flow out of two or three legs but not out of four. The splitter was modified to ensure that gas and coal streams were continuously accelerated as they passed through the splitter. The modified unit demonstrated satisfactory four way splitting during all fifteen coal flow tests completed with it. Secondary coal feed system pressure drops measured (Figure 5.10-17) showed good correlation with secondary coal flowrates.

Coal distribution test results for the final two coal flow tests, completed with the nineteen collection tubes in place are presented. For these tests the radially opposed injector configuration (Figure 5.10-7) was used. Coal distribution across the gasifier was very satisfactory and in excellent agreement with ideal and predicted values (Figure 5.10-18).

At the conclusion of this test program, the secondary coal injection system was ready for installation and evaluation in the HMF gasifier PDU during gasification tests.

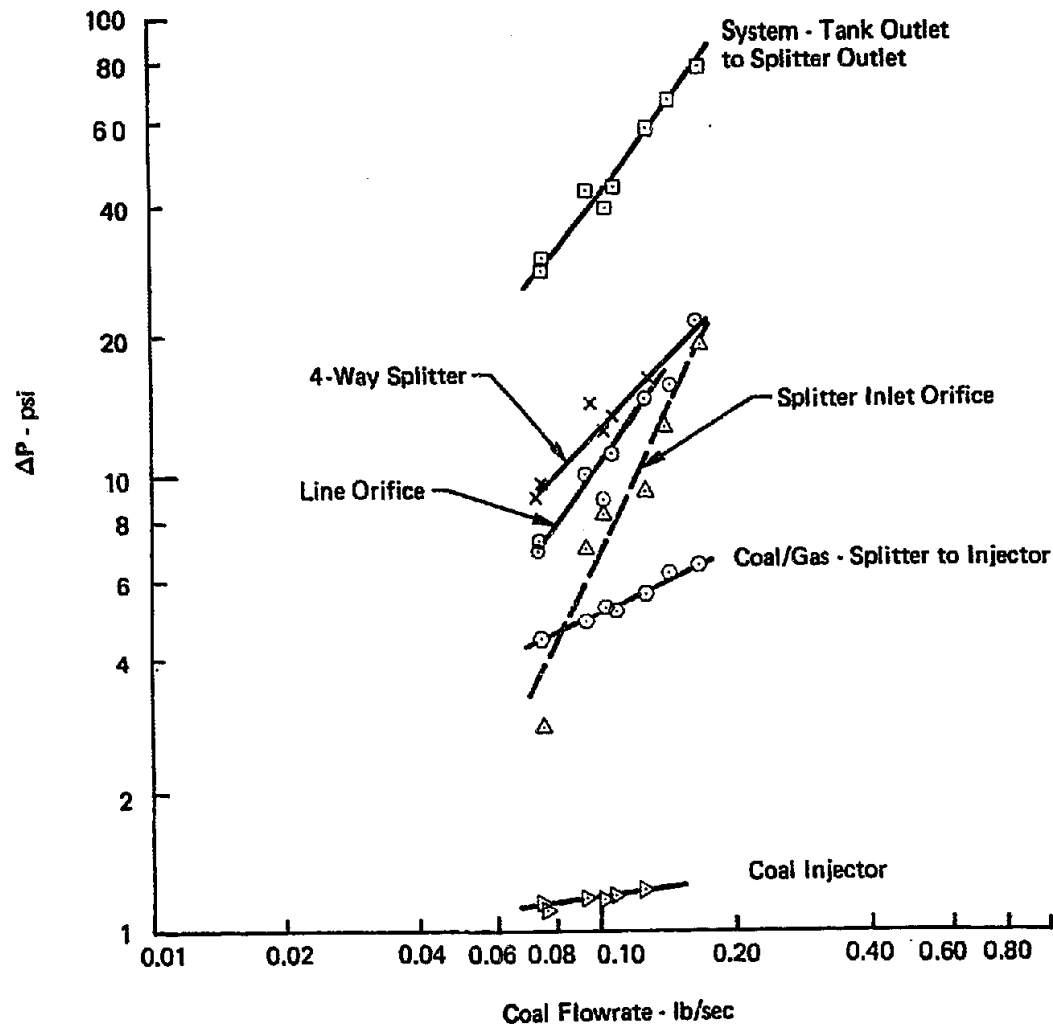


Figure 5.10-17. Secondary Coal Injection System Pressure Drop Characteristics

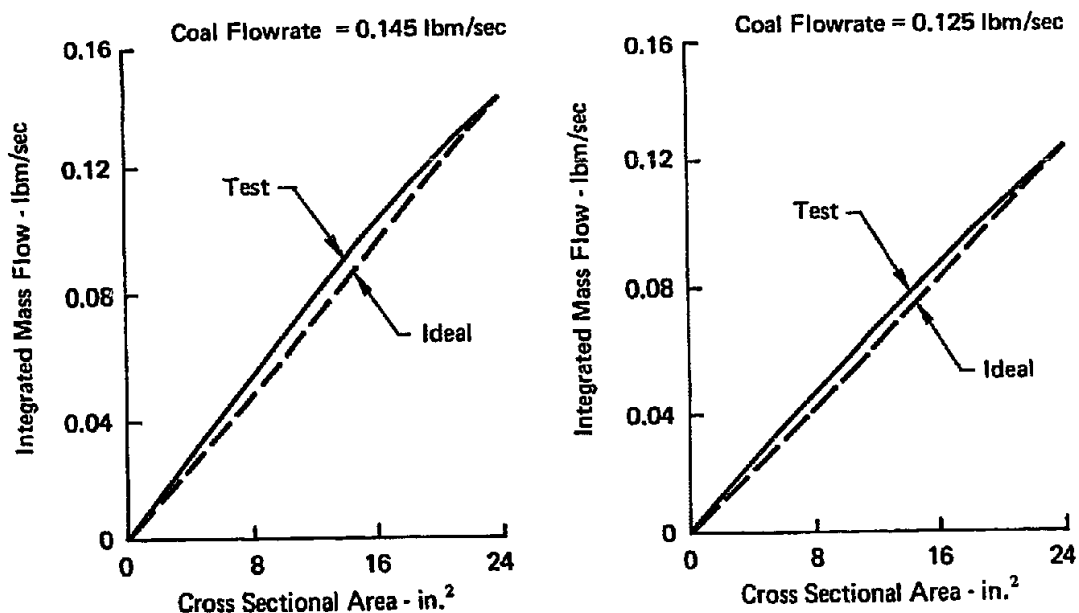


Figure 5.10-18. Integrated Mass Flowrates for Secondary Injection Cold Flow Tests

5.11 SLAG FLUXING TESTS

Slag fouling problems were experienced in the reactor head during the DOE sponsored air-blown HMF gasifier test program and were partially resolved. During a Bell sponsored oxygen-blown program, injector system modifications appeared to have essentially eliminated slagging problems. It was considered prudent, however, to address potential slagging difficulties and, in consequence, a subcontract was let to Alfred University Research Foundation (AURF) to investigate methods of reducing the viscosity of coal slag by means of the addition of fluxing agents.

The AURF task was conducted under the direction of Mr. Jeffrey Morris. A report of this work follows.

5.11.1 Objectives of Slag Fluxing Test Program

This work was performed to determine the effect of selected fluxing additives on the viscosity/temperature relationship for Pittsburgh Seam coal slag.

5.11.2 Literature Review

Many of the earlier studies of coal ash were aimed at clinkering problems in fuel beds. Later, studies of ash were concerned with the unique problems involved with slag-tap pulverized coal-fired boiler furnaces, where the viscosity of the coal-ash slag must be low to assure satisfactory removal of the slag (Ref. 5.11.1). Earlier work involved the cone fusion test (ASTM, D 1857-68) which attempted to correlate softening temperature with extent of clinkering. At best the cone-softening temperature divides coal ash into broad categories of fusibility – low fusion 1000 - 1200°C; moderate fusion 1200 - 1400°C, and high fusion 1400 - 1650°C. This data had limited use due to the difficulty of accurately translating this to slag flow conditions within the combustor. More useful data was obtained through high temperature viscosity measurements of molten coal slags.

Various methods of evaluating slag viscosity have been attempted, most of which are based on the measurement of the constant-speed torque required to rotate a bob in a slag melt, which is a function of viscosity. Since chemical analysis is generally more cheaply and easily performed than high temperature viscosity measurements, much of the work on laboratory measurement of coal-ash slag viscosity has been carried out with the object of finding a correlation between chemical analysis and viscosity-temperature properties.

To date, the most sophisticated attempt at correlating slag chemistry to actual units of viscosity is probably the work performed by Watt and Fereday. Through numerous measurements of viscosity of various slag chemistries, an equation was developed which predicts the viscosity of a fully melted, crystal free slag.

$$\log \eta = \left[\frac{10^7 M}{(t - 150)^2} \right] + C \quad \text{Eq. 5.11.A}$$

where η = Viscosity in (NS/m²) [multiply by 10 to obtain poise]

$$M = 0.00835 \text{ SiO}_2 + 0.00601 \text{ Al}_2\text{O}_3 - 0.109$$

$$C = 0.0415 \text{ SiO}_2 + 0.0192 \text{ Al}_2\text{O}_3 + 0.0276 \text{ Fe}_2\text{O}_3 \text{ (Equivalent)} \\ + 0.0160 \text{ CaO} - 3.92$$

$$\text{Fe}_2\text{O}_3 \text{ (Equivalent)} = \text{Fe}_2\text{O}_3 + 1.11 \text{ FeO} + 1.43 \text{ Fe}$$

Range of slag composition applicability:

SiO ₂ content	40% to 80%
Fe ₂ O ₃ content	3% to 30%
CaO content	2% to 30%
MgO content	1% to 10%
SiO ₂ /Al ₂ O ₃ ratio	1.4 to 2.4

Slag composition of the form

$$\text{SiO}_2 + \text{Al}_2\text{O}_3 + \text{Fe}_2\text{O}_3 \text{ (Equivalent)} + \text{CaO} + \text{MgO} = 100 \text{ (weight percent)}$$

5.11.3 Experimental Procedure

Synthetic slag mixes were prepared to simulate slag from Pittsburgh seam coal. To these mixes varying proportions of sodium oxide, calcium oxide, and borax were added to act as fluxing agents. The effects of the fluxing agents were determined by using a Brookfield Viscometer, with a platinum bob, to measure slag viscosity over a temperature range of 1275°C to 1550°C.

5.11.3.1 Slag Preparation – In reviewing the literature, it became apparent that a great number of researchers are using synthetic slags composed of reagent grade materials to represent the numerous coal ash compositions. Although this practice will allow a more precise batching of the experimental slags, one must question if these melts are representative of the slags which are developed from the

burning or gasification of coal. For this test program, therefore, it was decided to formulate the slags using ceramic raw materials when possible.

A "mother slag" was blended dry in a counter-current high intensity mixer. The fluxing cations of sodium, calcium, or boron were added as weight percent based on the oxide form. Sodium and calcium were added in the carbonate form and boron was added as borax ($\text{Na}_2\text{B}_4\text{O}_7$).

The "mother slag" formulation was based upon analyses of slag extracted from the HMF gasifier. The formulation and target chemistry was as listed in Figure 5.11-1.

Raw Material	Amount (lb)	Target Chemistry	
		Element	%
EPK Kaolin	55.71	SiO_2	51.4
Ohio Lime	4.45	Al_2O_3	23.3
Calcium Carbonate	0.26	Fe_2O_3 (equiv)	16.6
Sodium Carbonate	1.37	MgO	2.2
Silica Sand	19.80	CaO	3.1
Red Iron Oxide	14.67	TiO_2	1.2
Potassium Carbonate	1.25	Na_2O	1.0
Rutile	0.90	K_2O	1.2
Total	98.41		100.0

Figure 5.11-1. Formulation and Target Chemistry for Simulated Pittsburgh Slag

A total of eight "melts" were used during the viscosity test program. Slag chemistries determined using wet chemical techniques and atomic absorption are shown together with fluxing additions in Figure 5.11-2.

Melt No.	SiO_2	Al_2O_3	Fe_2O_3 (Equiv)	MgO	CaO	TiO_2	B_2O_3	Na_2O	K_2O	Addition
Target	51.4	23.3	16.6	2.2	3.1	1.2		1.0	1.2	--
IIA Base	51.8	25.4	14.2	1.6	2.6	1.3		1.1	2.0	--
IIA-3	50.4	24.7	13.8	1.6	2.5	1.3		3.8	2.0	3.0% Na_2O
IIA-4	51.1	25.0	14.0	1.6	2.6	1.3		2.5	2.0	1.5% Na_2O
IIA-6	50.4	24.7	13.8	1.6	5.4	1.3		1.0	2.0	3.0% CaO
IIA-8	49.0	24.0	13.4	1.5	8.2	1.2		1.0	1.9	6.0% CaO
IIA-9	49.0	24.0	13.4	1.5	2.5	1.2		6.7	1.9	6.0% Na_2O
IIA-10	50.8	25.0	13.9	1.6	2.5	1.3	2.0	1.0	2.0	3.0% Borax
IIA-11	50.0	24.5	13.7	1.5	2.5	1.3	3.5	1.1	1.9	6.0% Borax

Figure 5.11-2. Chemistry of Simulated Slag Mixes

5.11.3.2 Viscosity Tests – A Brookfield Viscometer was used with all measurements done at 10 rpm. A platinum spindle was calibrated to glass of known viscosity supplied by Brockway Glass. The slag compositions were premelted and fritted into large chunks for ease of charging in the high temperature viscosity setup. High-form alumina crucibles of 500 ml capacity were used to contain the melts. The furnace was gas-fired and all experiments were done at approximately 5% excess air. The melts were brought to 1425°C and maintained at this temperature for 16 hours to assure formation of a homogeneous liquid and equilibration with the atmosphere. At this point the bob was introduced into the melt, taking caution to note the depth so that this may be repeated as accurately as possible in subsequent viscosity runs. Apparent viscosity measurements were made approximately every 25°C with 10 minutes without viscosity change at constant furnace temperature as qualification for thermal equilibrium. These high temperature viscosity measurements encompassed a range of 1275°C - 1550°C.

5.11.3.3 Viscosity Test Results – The effects of the addition of differing percentages of sodium oxide, calcium oxide and borax to the base slag are shown in Figures 5.11-3 through 5.11-5.

The temperature-viscosity plots exhibit a hysteresis effect. This is manifested by a jog or discontinuity in the curves at the temperature points where the heating and cooling portions meet. The fact that the cooling curves are not continuations of the heating curves suggests that the slag viscosity is influenced by its previous thermal history. This characteristic might be explained by the fact that silicious glasses, or slags, are highly associated liquids in that the atoms and ions, of which they are comprised, are joined together in complex groups. For example, the silicon-oxygen tetrahedrons link together or polymerize into networks or chains of various sizes and shapes which can vary dependent upon thermal history and thus can result in viscosity variation. Contributing to the hysteresis effect can also be compositional variations resulting from incomplete dissolution and diffusion of raw materials.

It is of significance to note that when the equation of Watt and Fereday (Section 5.11.2) is applied to the modified slag compositions associated with calcium oxide additions, extremely good agreement is obtained between predicted viscosities and those measured during the rising temperature cycle of the tests (Figure 5.11-6).

The agreement would suggest the equation was derived from data obtained in a similar way.

The Watt and Fereday equation was further used to predict the potential effects of calcium oxide additions beyond the range tested in the subject program. The results presented in Figure 5.11-7, indicate that very significant reductions in slag viscosity should be achievable if calcium oxide is added to Pittsburgh seam slag in a weight ratio approaching 25:75. These results would indicate that should slag flow difficulties be experienced in an entrained flow gasifier, the addition of calcium oxide could prove to be an attractive solution.

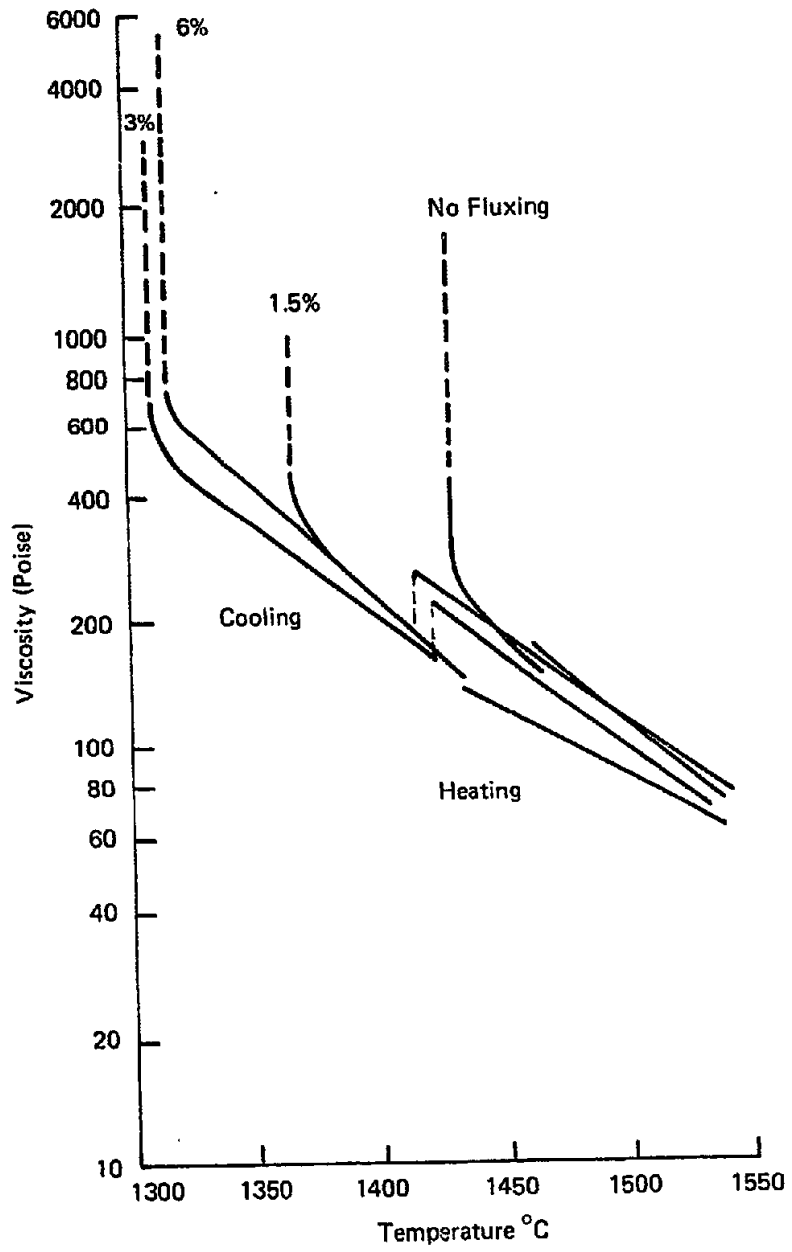


Figure 5.11-3. Effect of Sodium Oxide Additions upon Slag Viscosity

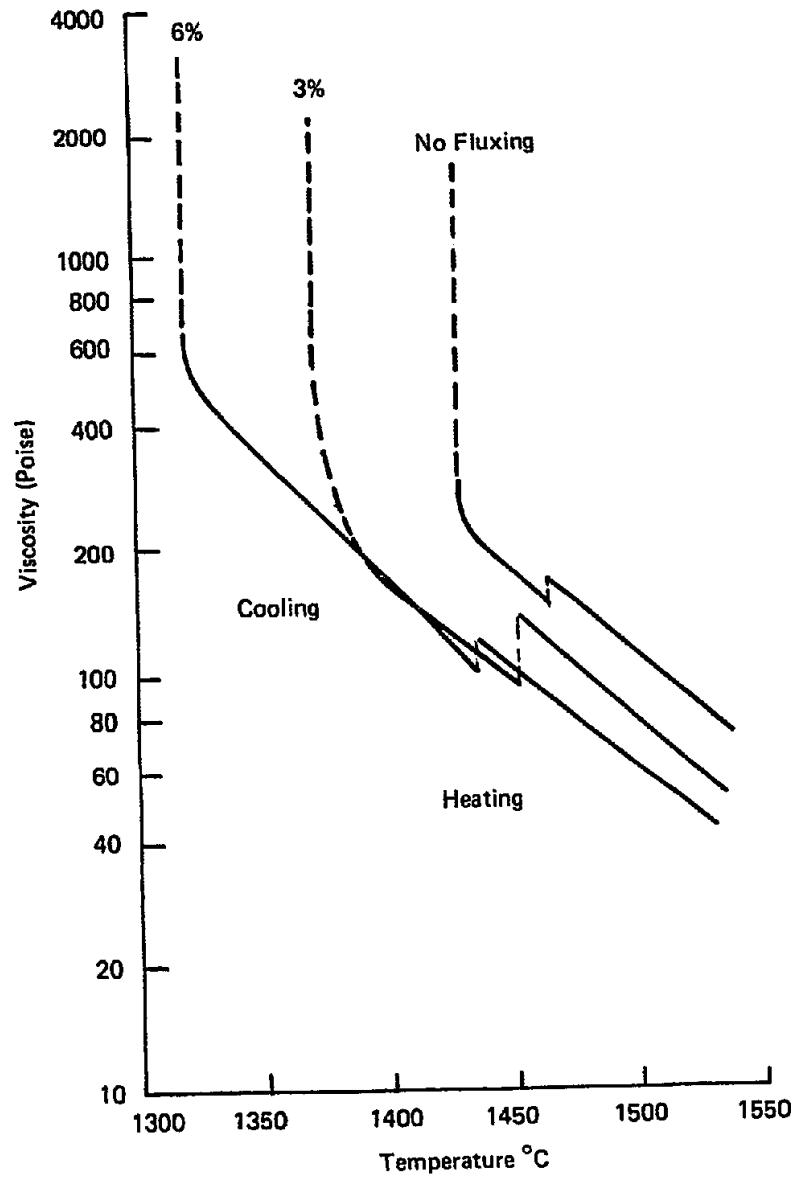


Figure 5.11-4. Effect of Calcium Oxide Additions upon Slag Viscosity

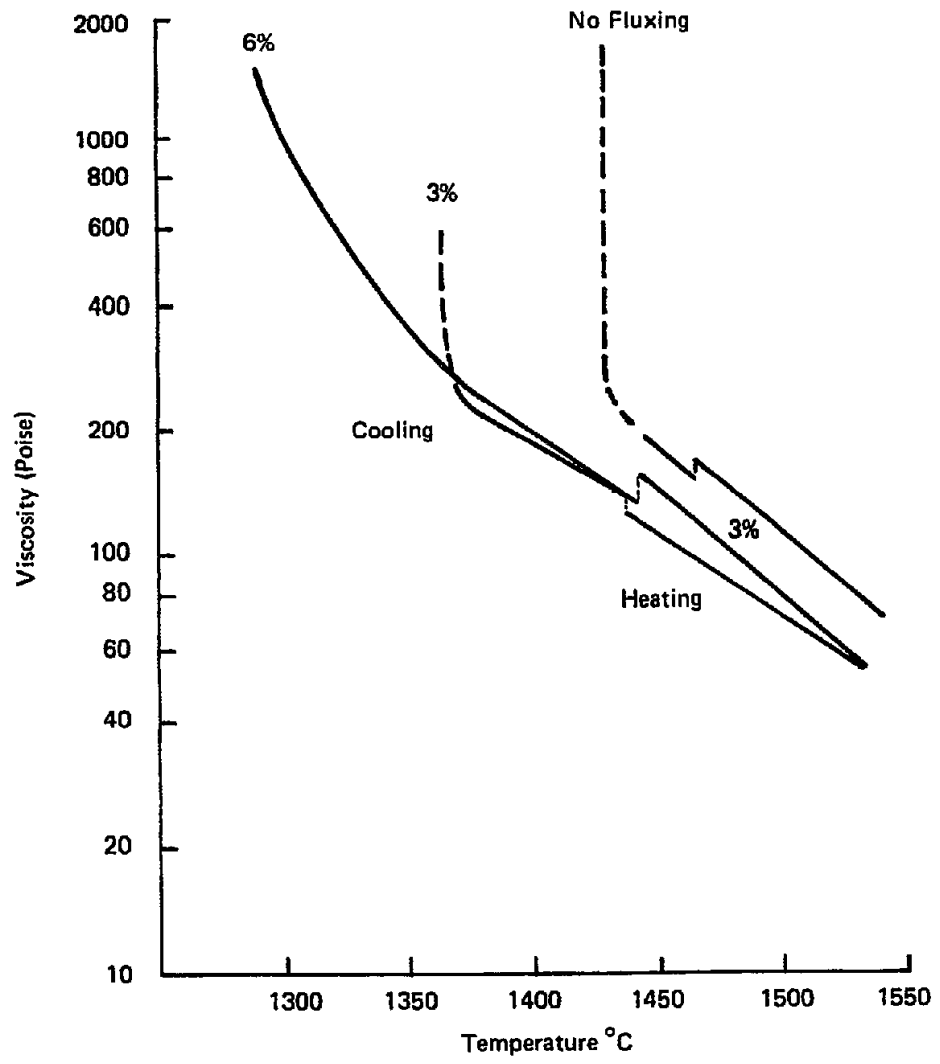


Figure 5.11-5. Effect of Borax Additions upon Slag Viscosity

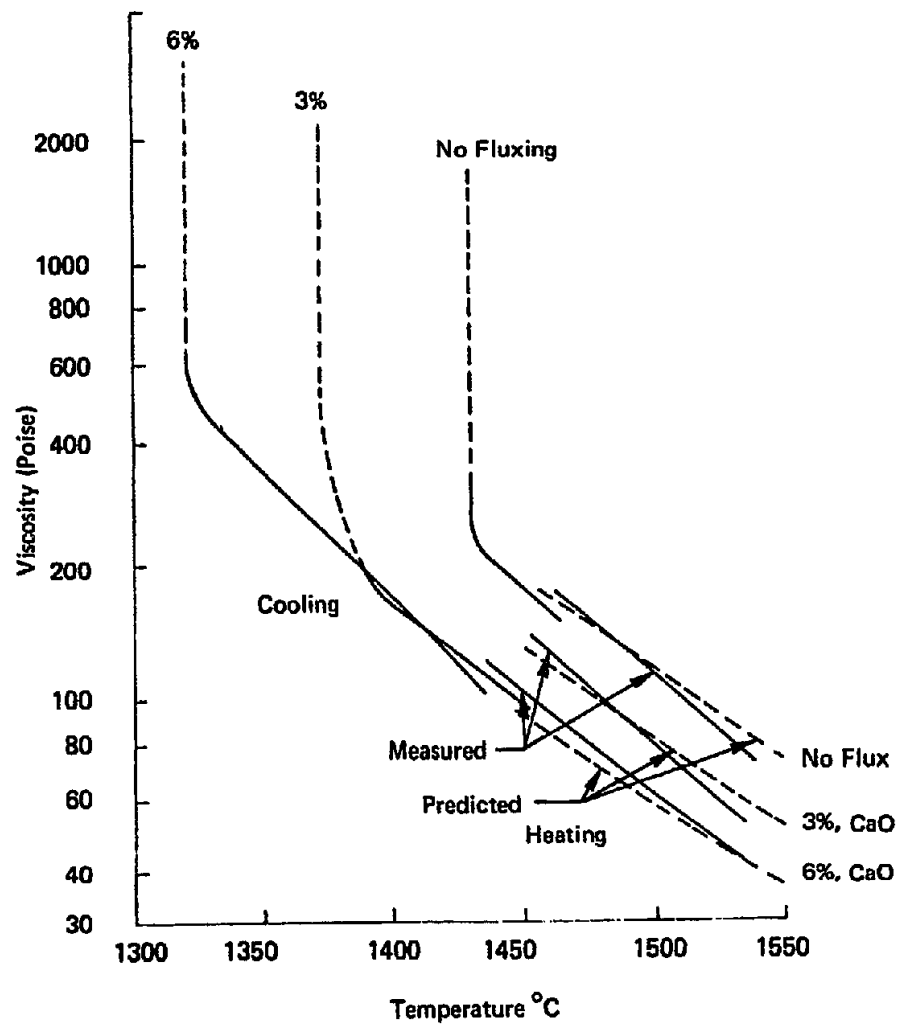


Figure 5.11-6. Comparison of Measured Viscosities with Values Predicted by Watts and Fereday Equation for CaO Additions to Pittsburgh Seam Coal Slag

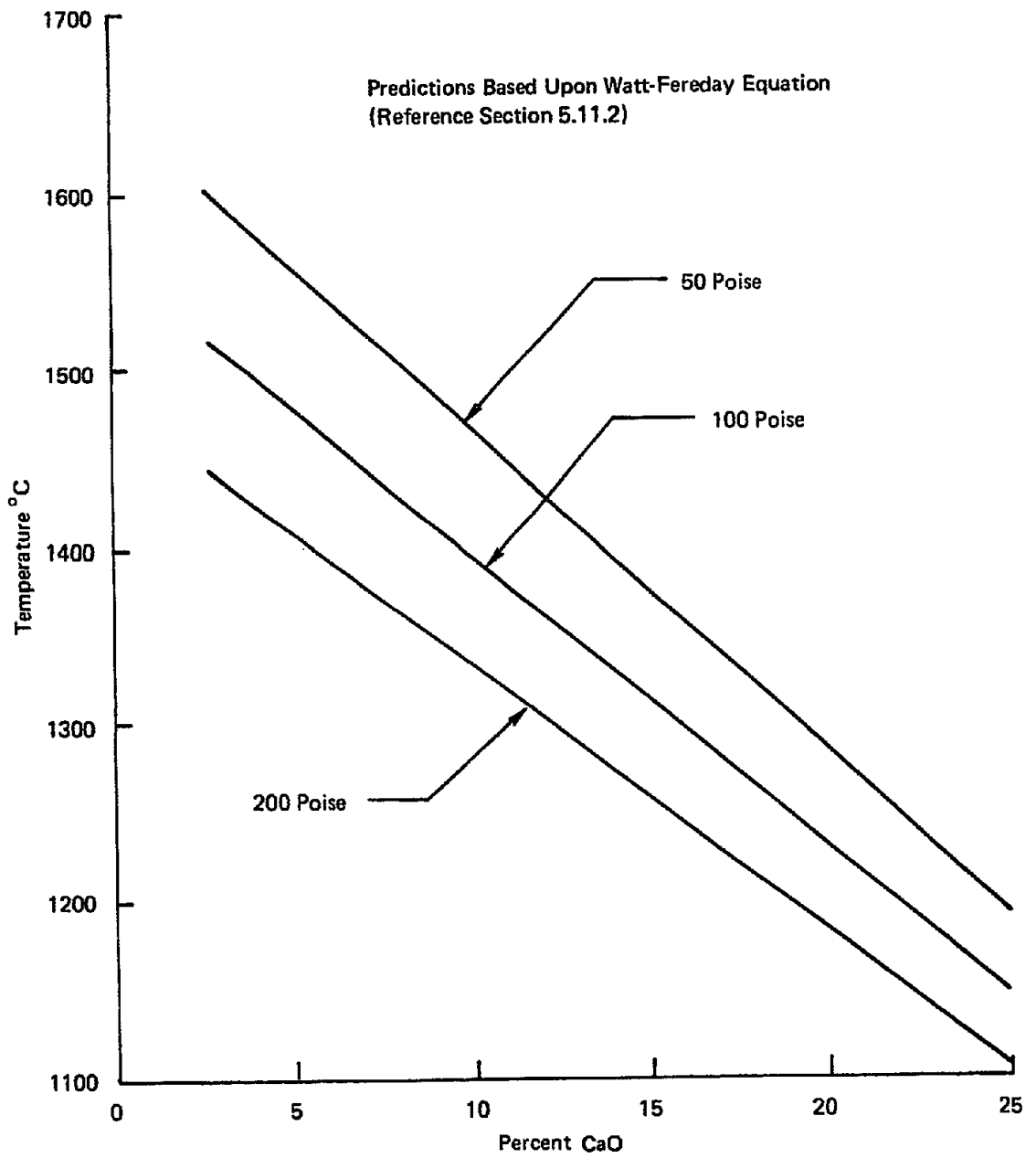


Figure 5.11-7. Predicted Effect of CaO Additions to the Viscosity of Pittsburgh Seam Coal Slag

6.0 COMPANY SPONSORED GASIFICATION TESTS

6.1 TEST SUMMARY

To conduct the originally planned gasification test program (Reference Figure 5.3-1) it would have been necessary to increase the contract value. The DOE and GRI elected not to do this. In consequence, Bell undertook to complete a reduced scope test program at its own expense with the view to conducting further contract work once the PDU was operational.

Seven gasification tests were conducted during which four configurations of gasifier were evaluated, and operation with two types of coal was demonstrated. Tests were run over a range of oxygen to coal and steam to coal ratios. Effects upon operation and performance were evaluated.

Figure 6.1-1 summarizes gasifier operating conditions and performance for the seven tests conducted. Oxygen/coal ratios, steam/coal ratios and carbon conversion efficiencies reported are average values for the total duration of the test.

Test No	Duration	Coal	O/A O ₂ /Coal Ratio	O/A Steam/Coal Ratio	O/A Carbon Conversion %	Remarks
3201	2 min	Pittsburgh	0.87:1	0.27:1	—	Checkout Test
3202	30 min	Pittsburgh	0.98:1	0.29:1	88.5%	Steam Injector Upstream of Water Cooled Cylindrical Section.
3203	15 min	Pittsburgh	0.94:1	0.32:1	85.0%	Steam Injector Downstream of Water Cooled Cylindrical Section. Safe Shutdown by Automatic Shutdown Device (ASD) when Metal Scale Plugged Coal Line Orifice.
3213	30 min	Pittsburgh	0.86:1	0.26:1	82.9%	Water Cooled Cylindrical Section Removed from Reactor.
3216	30 min	Pittsburgh	0.93:1	0.36:1	88.6%	Steam to Coal Ratio Adjusted during Test.
3223	9 min	North Dakota Lignite	0.77:1	0.26:1	95.0%	Inadvertent Shutdown due to Incorrect ASD Setting.
3225	30 min	North Dakota Lignite	0.77:1	No Steam	96.0%	Reactor Configuration Same as for Tests 3213, 3216, and 3223.

Figure 6.1-1. Summary of HMF Gasifier Operation and Performance

Analyses for coals used during test program are presented in Figure 6.1-2.

	Pittsburgh Seam Coal	North Dakota Lignite
Moisture (weight %)	2.4	9.1
Ultimate Analysis (weight % dry basis)		
Carbon	74.20	64.87
Hydrogen	4.93	4.17
Nitrogen	1.56	0.90
Oxygen	6.15	19.14
Sulfur	2.01	1.25
Ash	11.15	9.67
Higher Heating Value (BTU/lb)	13,256	10,800

Figure 6.1-2. Analyses for Coals Used During Gasification Test Program

6.2 GASIFIER CONFIGURATIONS

Gasifier configuration changes were all associated with the locations of the steam injector, and the water cooled cylindrical section, as shown in Figure 6.2-1. For tests 3201 and 3202, the steam injector was positioned upstream of the seven inch long water cooled section. For test number 3203, the steam injector was moved downstream of the water cooled section to assess the effect of a larger Zone A (oxidation) section. The water cooled section was removed for tests 3213, 3216 and 3223 to evaluate the effect of its removal. Test number 3223 was conducted using North Dakota Lignite as opposed to Pittsburgh seam coal, used for all previous tests. For test number 3225 the steam injector was removed to evaluate the effect of running without steam on the gasification of North Dakota Lignite.

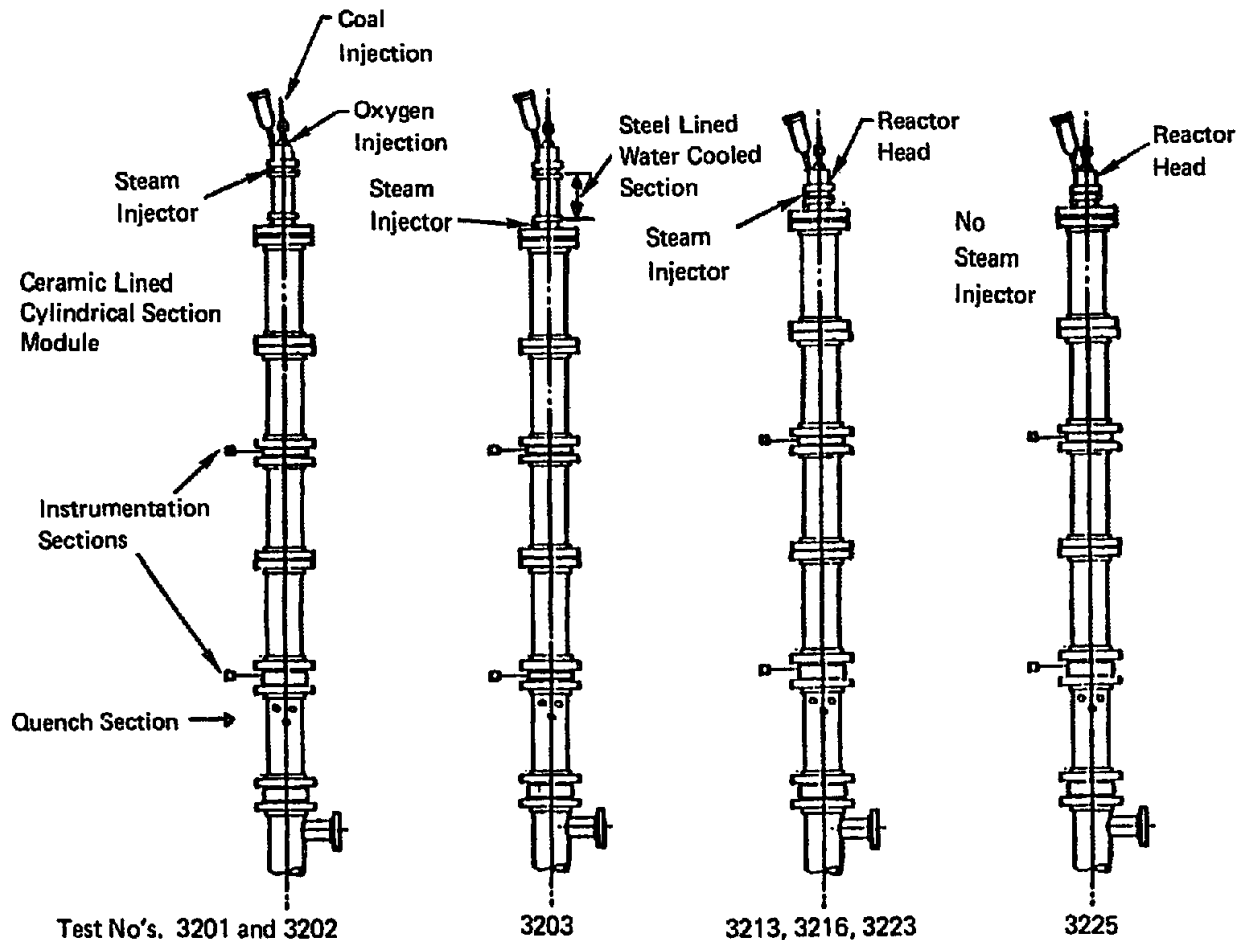


Figure 6.2-1. Gasifier Configurations Tested

6.3 GASIFICATION TEST PROCEDURE

The gasifier was operated at a coal throughput of nominally 1/2 ton per hour and at a pressure of nominally 220 psia.

The start sequence used throughout the test program was that developed during the PDU checkout tests (Section 5.9.2).

Gasifier startup was initiated by the test operator depressing the control panel FIRE button. The start sequence was then under the control of the programmable controller.

Adjustments were made, by the test operator, to the main gas trim valve (Figure 5.8-1) to establish and maintain a gasifier operating pressure of nominally 220 psia. Adjustments were also made to the coal feed tank pressure, the oxygen feed pressure or the steam feed pressure when it was desired to adjust the applicable reactant feed rate.

Product gas grab samples were taken from two stations in the gasifier and at the demister exit at three selected times during a test. The mass spectrometer was operated throughout a test and data, from which product species were calculated, were acquired at two minute intervals.

For five of the tests, shutdown was effected by the operator at the planned test duration. In the case of two tests, shutdown was effected by an automatic shutdown device. In all cases, the shutdown sequence was under the control of the programmable logic controller and all shutdowns were executed in a safe and predictable manner.

Upon test completion, data were obtained as defined in Section 5.7.1, and a material balance analysis completed. The gasifier head was removed, to facilitate inspection, and any required modifications were incorporated before preparing for the next test.

NOTE

The test number sequence is not necessarily consecutive since, in the interest of accountability, subsystem checkout tests, which may be performed between gasification tests, are also allocated test numbers.

6.4 GASIFIER OPERATION

Throughout all seven tests, gasifier operation was smooth and stable. Gasifier start, steady state operation and shutdown were satisfactory. No reactor failures or malfunctions occurred during the test program.

In two cases, tests numbers 3203 and 3223, the tests were terminated short of the planned thirty minutes duration. In both cases, the automatic shutdown device (ASD) which monitors coal flowrate detected out of tolerance conditions and initiated the automatic shutdown sequence.

The ASD shutdown experienced at fifteen minutes into test number 3203 was the result of a piece of weld scale (introduced into the system during a coal load tank modification) flowing with the coal and plugging the upstream orifice of the coal feed line. The shutdown command was issued within fifty milliseconds of the orifice plugging. Gasifier shutdown was safe and normal. The weld scale was removed from the feed line orifice. The coal load and feed tanks were connected in the coal flow test configuration (reference Figure 5.9-1) and the contents of the coal feed tank were successfully flowed back to the coal load tank via the repositioned coal feed line and orifices to ensure that no further pieces of weld scale were in the system.

The coal flow ASD shutdown experienced nine minutes into test number 3223 was the result of an incorrect ASD shutdown limit setting. The incorrect setting was made prior to test 3223 when the ASD limits were adjusted to accommodate the use of North Dakota Lignite. The limits were reset and test number 3225 was successfully run for the planned thirty minutes duration.

6.5 MATERIAL BALANCE

Gasifier inputs and products were collected, measured and analyzed as identified in Section 5.7.1. Material balances were calculated at four levels of analysis:

- I. Overall System Mass Balance for Complete Test
- II. Overall System Mass Balance by Element for Complete Test
- III. Element Balance for Specific Time Intervals
- IV. Element Balance for Individual PDU Components (Gasifier, etc.)

Examination of raw level II results, for the five tests in excess of fifteen minutes duration, shows:

- Overall system mass balances ranging from zero to ten percent shortage of products.
- Good carbon balance
- Approximately thirteen percent shortage in oxygen and hydrogen products for three tests.
- Some significant ash shortages.

Analysis reveals the missing oxygen and hydrogen to be in a mass ratio of approximately 8:1. This strongly suggests that the missing elements were combined in the form of water. During the test program, some problems were experienced with the functioning of the level sensor probes in the buffer tank located at the base of the condenser (reference Figure 5.7-1). In consequence, the buffer tank overflowed on occasions and condensed water was re-entrained in the gas stream and blown through the demister into the scrubber. The entrained water was thus lost to the material balance system.

Corrections were applied to the measured level II element balance, on the assumption that the missing oxygen and hydrogen, evident for three of the tests, was combined in the form of water and was lost as described above. The corrections made significant improvements in the overall material balances as well as the balances for oxygen and hydrogen.

The missing ash is believed to have left the system in the form of fly ash which was too small to be extracted by the cyclone. Examination of char particles by scanning electron microscope has revealed slag particles in the sub-micron range on the char surface. As char is consumed it is hypothesized that the sub-micron slag particles are released to become fine fly ash. Applying a fly ash correction to the material balance makes a small improvement to the overall material balance. Measured and corrected overall element balance data are presented in Figure 6.5-1.

The data indicate that following corrections, closure goals of better than $\pm 5\%$ for major elements are achieved. To eliminate the need for these corrections it is proposed to eliminate water carryover and to extract, collect and quantify fly ash. To prevent water carryover, the condensates collected in the buffer tank will be transferred to the condensate storage tank at five-minute intervals (well before the buffer tank could fill). This will be achieved by placing the function under the control of the programmable logic controller.

To collect the fly ash, a bag filter will be placed in the product gas line between the demister and the scrubber.

Test No.	Correction	Closure % $\left(\frac{\text{Input}-\text{Output}}{\text{Input}}\right) \times 100$					
		C	H	O	N	Ash	Overall
3202	As Measured	-0.5	-13.9	-13.2	13.9	-23.7	-9.7
	Water Carry Over	-0.5	+3.1	-0.3	13.9	-23.7	0
	Fly Ash Carry Over	-0.5	+3.1	-0.3	13.9	0	0.5
3203	As Measured	-1.0	4.0	1.6	-1.3	-8.0	0.8
	No Water Correction	1.0	4.0	1.6	-1.3	-8.0	0.8
	Fly Ash Carry Over	-1.0	4.0	1.6	-1.3	0	-0.3
3213	As Measured	1.0	-13.3	-11.3	2.4	20.9	-8.4
	Water Carry Over	1.0	+1.1	-0.1	2.4	20.9	+1.2
	Fly Ash Carry Over	1.0	+1.1	-0.1	2.4	0	+1.8
3216	As Measured	0	-10.2	-9.6	-2.8	-30	-10.4
	Water Carry Over	0	2.4	-0.2	-2.8	-30	-1.8
	Fly Ash Carry Over	0	2.4	-0.2	-2.8	0	-1.0
3225	As Measured	-0.1	-1.1	-4.1	-3.6	-51	-5.9
	No Water Carry Over	-0.1	-1.1	-4.1	-3.6	-51	-5.9
	Fly Ash Carry Over	-0.1	-1.1	-4.1	-3.6	0	-3.2

Figure 6.5-1. Measured and Corrected Overall Element Mass Balance

6.6 GASIFIER PERFORMANCE

Gasifier performance, measured during the final two minutes of the five thirty-minute duration tests is presented in Figure 6.6-1. Analyses of results from these tests together with results from tests 3203 and 3223 indicate the following:

Test	Coal	O ₂ /Coal	Steam/Coal	Dry Gas Comp (Mole %)				Conversion η	Cold Gas η	HHV (Moisture N ₂ & H ₂ S Free)
				H ₂	CO	CO ₂	N ₂			
3202	P	0.88:1	0.27:1	31	52	9	8	86%	68%	291
3213	P	0.89:1	0.27:1	31	52	9	7	87%	68%	291
3216	P	0.90:1	0.10:1	31	55	8	6	89%	72%	296
3225	NDL	0.75:1	No Steam	29	56	8	7	95%	76%	295

P Pittsburgh Seam Coal

NDL North Dakota Lignite

Figure 6.6-1. Gasifier Performance at End of Thirty-Minute Tests

1. No performance change could be detected as the result of moving the steam injector from upstream to downstream of the seven inch water cooled cylindrical section to produce a lower Zone A section. (Reference Figure 6.2-1, test numbers 3202 and 3203.)
2. The effect of removing the seven inch water cooled section was to reduce the heat loss from the reactor which in turn appears to have resulted in gasifier performance increase.
3. The gas composition at the upstream instrumentation section was essentially the same as the composition at the gasifier exit. This indicates that gasification reactions were essentially complete upstream of the first sample station.
4. Carbon conversion efficiencies of approximately 95% were obtained with the more reactive North Dakota Lignite. Removal of steam for test number 3225 did not significantly affect gasifier performance.
5. There was a marked increase in gasifier performance with accumulated running time. This is attributed to the effects of reducing heat loss from the gasifier reactants as the reactor ceramic walls heat up.

With regard to item 5, it should be noted that even at the thirty-minute data point the heat loss from the gasifier reactants to the gasifier walls was approximately 150 BTU/sec which has the effect of reducing the reactant gas temperature by approximately 700° F. In a commercial size gasifier, of say fifty tons per hour, the heat loss from the reactor and resulting gas temperature drop will be approximately one-tenth of losses experienced here. The effect, it is predicted, will be a reduction in oxygen consumption requirements of approximately ten percent from this factor alone.

Other work under way at Bell indicates that injector and reactor configuration refinements should enable a commercial size High Mass Flux gasifier to operate with oxygen consumptions only slightly higher than the theoretical minimum while achieving carbon conversion efficiencies in excess of 98%.

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