FINAL TECHNICAL REPORT
July 1, 2002, through September 30, 2003

Project Title: **COMMERCIALIZATION OF THE HYMELT® GASIFICATION PROCESS FOR ILLINOIS COAL**

ICCI Project Number: 02-1/US-1
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ABSTRACT

After receiving an award from DOE on September 19, 2002, EnviRes executed subcontracts with Kvaerner for engineering services, with Siemens Westinghouse for gas turbine modeling and combustion analysis and with MEFOS for large scale experimental testing of a new coal gasification technology called HyMelt®, co-developed by EnviRes and Ashland Petroleum, now Marathon Ashland Petroleum.

EnviRes developed an administration and financial management and reporting system acceptable to DOE for this project. EnviRes conducted an extensive plant site identification and screening process utilizing a weighted matrix evaluation process. A twenty-acre site located in the southwest area of East St. Louis, IL was selected which is adjacent to the industrial complex of Sauget and has access to excellent barge, rail and trucking bulk transportation infrastructure. Preliminary environmental/geotechnical reviews and site design was completed. EnviRes secured local financial support for the project from the East St. Louis TIF District and Enterprise Community.

EnviRes obtained the feed coal, pulverized it, and shipped it to MEFOS in Sweden for testing. EnviRes developed and began process simulation activities with Kvaerner and reactor thermodynamic studies with MEFOS. EnviRes and MEFOS designed and implemented a test plan for the project. Large-scale gasification tests were performed on June 3-13, 2003. EnviRes and MEFOS deemed carbon dissolution in the metal to be unsatisfactory. EnviRes and MEFOS developed a different feed system and tested it on September 2-4, 2003. Preliminary indications are that sufficient carbon dissolution was attained meeting our commercialization criteria. These activities will be incorporated into a design basis memorandum, started under this contact and to be finished under DOE funding.

EXECUTIVE SUMMARY

EnviRes co-developed with Ashland Petroleum Company, now Marathon Ashland Petroleum, LLC a new coal gasification process through laboratory scale testing. This process employs direct coal injection into molten iron without oxygen or steam. At molten iron temperatures, the carbon in coal rapidly dissolves in the metal. Iron was selected because it has a relatively high solubility for carbon and because dissolved carbon in iron oxidizes to carbon monoxide before significant iron oxidation occurs. In this process, most hydrogen associated with coal forms molecular hydrogen in the gas phase. Nearly all nitrogen in the coal becomes molecular nitrogen and also enters the gas phase. A substantial amount of the sulfur in the coal converts to hydrogen sulfide, also a gas. The remaining sulfur is captured in the slag layer. Oxygen contained in the coal becomes carbon monoxide and enters the gas phase. Most inorganic constituents (ash) become molten slag that floats on the molten iron as in steel making. The slag must be periodically or continuously tapped from the reactor. Mercury present in coal volatilizes into the gas stream where it can be easily removed by downstream treatment. This results in a product gas stream that can be up to 90% hydrogen as it leaves the reactor depending on the coal composition.

When the carbon content in the metal nears the solubility limit, coal feed is interrupted. Oxygen is then injected into the metal to convert the dissolved carbon to carbon monoxide. Oxygen injection reduces the carbon in the metal to the desired level. Oxygen injection provides more heat than the endothermic coal injection step requires so some steam or other temperature-moderating stream must also be injected during oxygen injection to keep the temperature of the metal at the desired value. If steam is used as the temperature-moderating agent, it reacts with carbon dissolved in the molten iron to form hydrogen and carbon monoxide. This reduces the oxygen requirement somewhat. This means that the process operates in overall heat balance and does not need any additional heat input. If two reactors are employed so that one of the two is always making a hydrogen rich stream and the other is always making a carbon monoxide rich stream, appropriate valving can be utilized so that there is always a steady stream of hydrogen rich gas and a steady stream of carbon monoxide rich gas.

The purposes of this program were to perform large scale (up to 3 tons/h coal feed) testing of the process and demonstrate performance parameters that are required for commercial practice of this technology and to develop a Design Basis Memorandum (“DBM”) for the construction of a commercial scale plant. In a DOE funded portion of this work, EnviRes elected to do testing at a metallurgical research facility (MEFOS) in Sweden because they had nearly all of the equipment necessary for testing in place. MEFOS already had a trained staff that was very skilled in doing this type of work. EnviRes was able to perform this testing for less than one tenth the cost of building the equipment from scratch and saved several years in accomplishing the work. As MEFOS generates data in testing, EnviRes and MEFOS review it and provide sufficient data to Kvaerner to develop the DBM and to assess the economic impact of hydrogen produced by HyMelt on refinery economics. Work on the DBM started under this contract and will be completed under DOE funding.

EnviRes and Siemens Westinghouse Power Corporation have a contractual agreement to model the use of the carbon monoxide rich gas in a large gas turbine, after completing the modeling to perform combustion testing in the Pittsburgh, PA pilot facility of Siemens Westinghouse Power Corporation and then together with EnviRes to model the cost of electrical power production using HyMelt fuel gas. Siemens Westinghouse Power Corporation and EnviRes started work under this contract. DOE funding will be used to complete the contract.

The demo/commercial plant will be built at an industrial site consisting of 20 acres located in the southwest area of East St. Louis, IL adjacent to the existing industrial complex in Sauget, IL. The HyMelt® demo/commercial plant will utilize its low cost carbon monoxide rich fuel gas and hydrogen to attract other industries to locate in the surrounding area. The proposed plant site has access to State Route 3, a major four-lane highway suitable for heavy truck traffic. The transportation of Illinois coal to the site will be accomplished by multiple transportation options consisting of three port facilities with barge-to-rail or truck capacity and direct access on Gateway Railroad and Illinois Central Railroad lines with switching facilities accessing nine railroad lines. The site is within trucking distance of the southwest Illinois coal fields. The industrial complex located just across the railroad tracks from the proposed site provides an existing market for the low cost HyMelt® industrial gases. The site already has the appropriate industrial zoning and the environmental and geotechnical studies identified no material concerns regarding the utilization of this site for a HyMelt® plant.

EniviRes has received substantial community and local governmental support for this project. The East St. Louis Black Chamber of Commerce has endorsed this project. The City of East St. Louis and the Enterprise Community has committed $2.5 million for infrastructure and other cost eligible expenses in support of the project. Other funding especially from the St. Louis Regional Empowerment Zone is expected.

The United States Department of Energy funded the testing in Sweden and part of all of the other work in this program under Cooperative Agreement Instrument Number DE-FC26-02NT41102 executed on September 19, 2002.

OBJECTIVES

The technical objectives for this project stated in this agreement are the following:

1. HyMelt® computational modeling. This includes modeling the chemical reactions that occur in the reactor, particulate generation in the reactor as a function of operating parameters and overall process simulation of a generalized HyMelt® plant.

2. Generate data necessary to prepare a design basis memorandum (DBM). This would incorporate all design features that are non-site specific necessary to design a minimum size commercial HyMelt® plant. This would include detailed reactor design, sizing and performance requirements for a requisite air separation unit (ASU), a complete process flow diagram (PFD), a complete piping and instrumentation diagram (P&ID), complete stream flow tables containing mass flow rates, stream compositions, stream temperatures, stream pressures and stream phases, sufficient information to perform a capital and operating cost estimate and sufficient information to perform a commercial plant risk assessment.

3. Assess the economic impact of The HyMelt® Process hydrogen production on refinery operations.

4. Model the cost of electrical production using HyMelt® syngas.

INTRODUCTION AND BACKGROUND

The HyMelt® process is a new coal gasification technology initially co-developed by Ashland Petroleum Company, now Marathon Ashland Petroleum, and EnviRes LLC. Several[1][2][3][4] molten iron gasification technologies have reached various stages of development using coal, oxygen, steam and lime simultaneously injected into molten iron producing a single syngas stream mainly containing carbon monoxide and hydrogen. The HyMelt® process is unique in that coal is injected separately from oxygen and steam to produce a hydrogen rich gas stream and a separate carbon monoxide rich stream when oxygen and steam are injected. EnviRes intends for the HyMelt® process to operate at elevated pressure, preferably in the range of 30 atmospheres so that reactor size and gas compression costs are greatly reduced.

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[1]Axelsson, C.L., Kaufmann, D., and Krister,T., "The CIG Process for Smelting Reduction and Coal Gasification", Scandinavian Journal of Netallurgy (17) (1988):30-37

[2] Barin, I., Modigell, M., and Sauert, F., "Thermodynamics and Kinetics of Coal Gasification in a Liquid Iron Bath", Metallurgical Transactions B (18B) (1987) : 347-353

[3] Axelson, C. L., Sato, K., Torsell, K., and Torneman, B., "The P-CIG Process for Coal Gasification", Coal Power 87 Conference, Dusseldorf, October 1987.

[4] Okamura, S., Sueyasu, M., Fukuda, M., Furujo, S., and Okane, K., "Coal Gasification using a Molten Iron Bath", International Workshop on the Science of Coal Liquefaction, Lorne, Victoria, Australia, May 1982

Early experimental work sought to maximize data unique to the HyMelt® concept at minimum cost. We built an induction-heated reactor with a 300 lb metal capacity. Since others had demonstrated coal injection (with oxygen and steam) at rates of up to 20 tons/hr, we did not see coal injection as a major feature to be initially demonstrated. The small size of the test reactor precluded the use of commercial, water-cooled lances making solids injection a difficult task. Instead, we focused on important reactions that were unique to the HyMelt® concept. Our initial work involved the injection of propane and later ethane into the molten metal bath. The depth of metal was approximately 24 inches resulting in a maximum practical injection depth of approximately 18 inches. At this depth we were able to produce gas streams that were in excess of 99% hydrogen. Other tests using oxygen and later steam and carbon dioxide demonstrated that near thermodynamic equilibrium could be achieved as far as the compositions of the gases leaving the reactor were concerned. In later tests the metal bath was doped with sulfur to approximately 1 w% sulfur. We injected hydrogen and later ethane into the metal producing gas streams containing up to v1% H_2S in mostly Hydrogen. These tests together with the earlier work by others in large scale coal gasification with molten iron convinced us that the HyMelt® concept was viable if mechanical means could be found to practice the technology.

EXPERIMENTAL PROCEDURES

Generating data for the design of a commercial plant was crucial to the success of this project. Such data must be generated in large equipment to minimize the uncertainty of scale change. EnviRes decided to perform this testing at MEFOS (a Swedish acronym for Stiftenlsen f r Metallurgisk Forskinning, in English this translates to “The Foundation for Metallurgical Research”) in Luleå, Sweden. EnviRes selected MEFOS for the following reasons:

1. MEFOS has nearly all of the equipment necessary for these tests.

2. MEFOS conducted several large-scale coal gasification tests using molten iron in the 1980’s.

3. MEFOS has a complete staff of technically trained people necessary to perform these tests.

4. MEFOS does contract research and does not retain any intellectual property from the tests.

5. EnviRes performed a survey and could not find any other facility in the world that could meet or even come close to these criteria.

If EnviRes had elected to build a test facility to perform these tests and somehow find properly trained people to operate it, the cost would have been 10 to 20 times the cost of using MEFOS. The time saving resulting from using MEFOS is at least a factor of 5.

All gasification tests take place in what MEFOS calls the universal converter. The universal converter is essentially a modified, highly instrumented, basic oxygen furnace (BOF). Figure 1 is a photograph of the universal converter.

Figure 1. The Universal Converter at MEFOS

The universal converter occupies the center of Figure 1. A water-jacketed hood where the product gases are combusted sits atop of the universal converter. The coal feed lance, oxygen lance, sample probe and flux addition lines penetrate the hood just above the 45° bend. Tuyeres located in the bottom (not in view) can inject oxygen and/or solids. The molds in the left foreground obscure the pit below the universal converter. Slag tapping and metal tapping are done in the pit to avoid spillage on the work floor. The pit also helps contain accidental breakouts of metal from the vessel. The control room lies behind and to the right of the universal converter. Trunnions support the universal converter so that it can be tilted for receiving hot metal as well as for pouring slag and/or metal.

Technical data for the universal converter are as follows:

1.	Maximum heat size	6,000 kg
2.	Furnace inside diameter, unlined	2.0 m

3. Furnace inside diameter, lined 1.41 m
4. Furnace depth (tangent to tangent) 2.0 m
5. Overall furnace length 3.25 m
6. Furnace volume, lined 3.8 m^3
7. Oxygen flow rate 0.5 m^3n/s

Testing performed in June, 2003, used separate, top entry (through the hood) lances, one to inject feed and the other to inject oxygen. Lime, dolomite (to adjust the slag) and scrap (for cooling) could be added separately. A bottom stirring tuyere used nitrogen. A top entry sample probe collected both dust samples and gas for online analyzers. The sample probe was only inserted into the converter during coal injection. Separate infrared devices continuously analyzed for carbon monoxide, carbon dioxide and hydrogen, a paramagnetic device determined the oxygen content. A quadrapole mass spectrometer also analyzed the gas from the sample probe.

A water-jacked hood collects all gas leaving the universal converter by operating at sub-atmospheric pressure. The hood also draws in a large quantity of ambient air with the converter gas. This results in immediate and near complete combustion of the universal converter product gas stream. Safety considerations in avoiding potentially explosive mixtures in downstream gas processing equipment dictate combustion of product gases. A venturi meter measures the total mass flow of the combusted gas. Separate infrared analyzers determine the carbon monoxide, carbon dioxide and sulfur dioxide content of the combusted gas. A paramagnetic analyzer determines the oxygen content of the combusted gas. MEFOS also measures the temperature and pressure of the combusted gas. A proprietary data acquisition system accesses information from all sensors and analyzers. An isokinetic sample probe can sample the combusted gas for particulate. Large, water-cooled exchangers quench the combusted gas to near ambient temperature. A venturi scrubber removes nearly all of the particulate matter and some of the sulfur dioxide from the combusted gas. A dry baghouse can collect large particulate samples from the combusted gas as desired. A large centrifugal blower downstream of the gas cleanup train maintains the system at sub-atmospheric pressure and drives the gas flow.

The large SSAB steel plant, located nearby, provides pig iron, ferrosulfur, ferrosicila, ferrovanadium oxygen, nitrogen, argon and propane as needed. MEFOS charged pulverized Illinois #6 coal to a lock hopper capable of holding approximately 1000 kg. Load cells in the legs of the lock hopper continuously indicate its weight to the data acquisition system. MEFOS designed the lock hopper for a pressure rating of 10 atmospheres. The lock hopper was typically pressured to a pressure of 7 atmospheres with nitrogen. A flexible hose connected the lock hopper to the injection device (a lance in this case).

Each day MEFOS melted the metal to be used for testing in an electric arc furnace, they poured the hot metal into a transport ladle supported from a load cell for weighing and charged it into the universal converter. MEFOS tilted the universal converter to its upright position and decarburized the metal by oxygen blowing to get the carbon content in the range of 0.5 w% to 0.7 w% and the temperature in the range of 1,550°C. Samples of the metal and its temperature were taken during the oxygen blowing. At the end of oxygen blowing, the vessel was titled to get a slag sample, a metal sample and the melt temperature. Oxygen blowing typically requires 15 to 30 minutes. The oxygen lance has an outlet velocity of 2.0 Mach. MEFOS deemed samples taken in the tilted position to be more representative as a result of additional mixing during tilting. MEFOS determined in earlier studies that a typical heat loss for the universal converter was approximately 30 Mj/min. After sampling, MEFOS returned the universal converter to its upright position.

MEFOS then injected coal feed to generate a hydrogen rich stream. MEFOS used a separate, water-cooled lance for Coal injection. The nozzle was sized to give a velocity of approximately 0.8 Mach. Coal injection rates varied from 5 to 20 kg/min.

MEFOS taps the universal converter at the end of every operating day. MEFOS weighs the recovered metal and slag separately. The metal is cast into ingots that may be reused or sent to the SSAB steel plant.

RESULTS AND DISCUSSION

Task 1.a Project Management and Administration

Sub-contracts:

Delay in executing the DOE award for this project caused most activities to be set back until after September 19, 2002, the date that the DOE agreement was finally executed. Our internal planning allocated four weeks for the drafting and approval of sub-contracts with our primary consultants MEFOS, Kvaerner U.S., and Siemens Westinghouse Power Corporation. We were comfortable that four weeks would be sufficient time as the financial terms and conditions, and agreed upon tasks and resource allocation had been previously negotiated and agreed upon with the sub-contractors. This was our first contract with DOE and due to our inexperience we underestimated the complexity and shear volume of additional contractual requirements caused by compliance with an astonishing array of Federal Contract Regulations. Kvaerner and Siemens were somewhat familiar with the requirements and for other than some additional discussions regarding allocation of intellectual property rights, the actual drafting of the contracts including all federal language requirements and numerous incorporation by reference to other Federal Regulations, the contract drafting with Kvaerner and Siemens proceeded with only some delay. However, the MEFOS international contract and a determination of which Federal Regulations were or were not applicable to a foreign entity became very problematic. We retained additional legal counsel experienced in federal contractual matters and focused our efforts on the sub-contract with the shortest “critical path” – the MEFOS contract.

Several drafts of proposed contract language and Federal Regulation incorporation was submitted to MEFOS. Unfortunately this was also MEFOS’ first experience with a contract containing U.S. Federal contract regulations. It took several weeks and many “coaching” sessions with our legal counsel and significant efforts from EnviRes’ senior staff and in particular a great deal of time from our CEO, Mr. Ward, to achieve a level of understanding on the part of MEFOS regarding the complicated contract. After three months of effort we executed the MEFOS contract on December 20, 2002. The MEFOS process provided helpful experience in federal contract requirements. We were able to execute the Kvarner sub-contract on December 3, 2002. We purposely focused on the Siemens' sub-contract last as its required tasks were scheduled for performance later in the project. The Siemens sub-contract was executed on May 16, 2003.

The delay in sub-contract execution and in particular the three-month delay in the execution of the MEFOS contact caused the project to be behind schedule. After execution of the MEFOS sub-contact we focused on shorting the time to complete the remaining tasks in the "critical path." On June 12 we completed the first round of atmospheric tests at MEFOS and considered the project back on schedule.

Administrative and financial management systems:

In order to establish a financial accounting system suitable for tracking federal and state contracts, EnviRes formulated a multi-step process to achieve federal and state reporting requirements. First, a consultant was hired with experience in managing the financial reporting requirements of Department of Energy contracts. Upon his recommendation a CPA firm was hired, also with DOE experience, to revise the company's chart of accounts and financial reporting processes from the existing private business orientation to a chart of accounts and reporting system suitable for DOE financial allocation and documentation. This included the preparation of the company's Policies & Procedures Manual which addresses the process for employment, equal employment, discrimination, conflicts of interest, work product ownership and confidentiality, time keeping, compensation, leave time, benefits, job conduct, internal accounting controls, purchasing and receiving procedures, capitalization and inventory procedures, travel policies and expenses and billing and collections. The new financial reporting and management system was implemented and in January a full-time controller was hired to maintain the accounting system.

The next step in the process was to request an audit by the Defense Contract Audit Agency which DOE uses to conduct financial audits of it contractors. The initial audit was requested in October and was conducted from January 15th through January 17th. In the exit conference on January 17th the auditor identified five areas of deficiencies regarding job cost accumulation, calculation of indirect costs, and a "minor revision" to the time keeping procedures. EnviRes agreed with the audit findings and proposed several actions for remediation of the deficiencies which were deem to be a sufficient plan that upon implementation by EnviRes would provide for an accounting system adequate for the accumulation of costs under Government contracts. EnviRes immediately implemented the required changes to its financial management system and a follow up audit was requested. A second audit was conducted on July 9th and 10th. The audit report issued on July 25th concluded that EnviRes' accounting system is "adequate for accumulating costs under Government contracts" and said costs were appropriately reported in the company's financial statements and billings for calendar year 2002 and to date in 2003.

Project site selection and development:

EnviRes went through an extensive search and evaluation process to select the site for the first HyMelt® plant. A list of site qualification criteria was developed and a weighted matrix calculation was used to rank sites that met our initial screening criteria. Prospective sites in four areas of Illinois were evaluated over a ten-month period before the final site selection was made.

The East St. Louis area was evaluated higher in all selection categories except for one and was our first choice for the HyMelt® demo/commercialization plant.

- **Transportation –** East St. Louis is a major bulk transportation corridor with access to major barge traffic with loading and transfer facilities, nine major railroads with extensive switching and transfer facilities and four major interstate highways. It is served by several airports including St. Louis-Lambert International. Over 350 local, intra-state and interstate common and specialized carriers operate within the region.

  The specific site is adjacent to Gateway Railroad lines and the Terminal Railroad Wiggins switching yard which can provide rail access to the Illinois coal mines and provide rail switching services for the plant. The site is within 500 yards of the Cahokia marine terminal which has extensive barge handling facilities providing feedstock delivery options and existing unit train unloading capacity. The site is served by Monsanto Avenue with direct access to Illinois State Route 3 –a major trucking corridor.

- **Access to Illinois coal markets -** Close access to the large reserves of Illinois high btu, low cost coal combined with direct rail or truck delivery options are major advantages of the site in East St. Louis.

- **Access to markets** for the sale of HyMelt products - The site is close piping distance to the industrial complex of Sauget, Illinois. The industrial complexes of Ethyl, Big River Zinc, Solutia, and Cerro Copper are all located just across the railroad tracks from the proposed plant site. EnviRes has discussed usage of HyMelt® gases with the plant managers for Ethyl, Big River Zinc, Solutia, Cerro Copper, BOC Gases, Gateway Gases, and the Trade West Incineration Plant. Demand for hydrogen and synthesis fuel gases are several multiples larger than the anticipated production levels of the Hymelt® plant. In fact, three of the industrial plants could each by themselves consume HyMelt's entire synfuel gas product stream. Overall, this site has great access to markets for Hymelt® products.

- **Labor –** The one category that was of concern for the East St. Louis site. The City has a population that has been declining for several decades and now is less than 32,000. The population base may not have sufficient education or training for the labor needs of the plant. However our discussions with plant managers in the adjacent industrial complex of Sauget did not identify material labor shortages. In addition, our discussions with the City has resulted in a proposed joint effort to establish and fund an ongoing employee training and qualification program that will benefit not only access to qualified labor for EnviRes but also for the City and other industrial facilities in the area. The training program will be modeled after a successful program implemented by Ashland Oil, Inc. for its refineries in eastern Kentucky and will utilize existing training facilities in East St. Louis.

- **Expansion –** East St. Louis has available several industrial sites and many more are expected to be available in the future that would meet requirements for a HyMelt plant site. The current site has expansion capacity that could be utilized for a gas fired turbine to generate electrical power or space to build the next HyMelt® plant, a larger facility expected to be 5000 tons/day with an attached electrical power plant.

The economic development office of East St. Louis identified eight potential industrial sites for consideration by EnviRes. After 10 months of evaluation and negotiation, 21 trips to East St. Louis by staff of EnviRes, a review of many local planning documents including: i.) the Comprehensive Plan of St. Clair County prepared by Woolpert in Association with Thouvenot, Wade and Moerchen, Inc., ii.) the Final Existing Conditions and Market Analysis for the East St. Louis Waterfront Development Master Plan-Part 2 prepared for the United States Army Corps of Engineers St. Louis District by Horner & Shifrin, Inc., iii.) a Phase I Environmental Site Assessment prepared by Herzog, Crebs & McGhee and iv.) Geotechnical Reports prepared by Herzog, Crebs &McGhee, LLP the site for the HyMelt® plant to be located in East St. Louis was selected. The site has the appropriate industrial zoning and the environmental and geotechnical studies identified no material concerns regarding the use of the site for a HyMelt® plant. On June 27, 2003 a Letter of Intent and Option to Purchase was entered into with RiversEdge Development, LLC for 20 acres with an option to purchase an additional 25 acres. Preliminary site engineering and design work has been completed by EnviRes.

EnviRes has received substantial support from the local community and the City of East St. Louis for its HyMelt® project. On February 17, 2003 the East St. Louis Black Chamber of Commerce endorsed the HyMelt® project and agreed to facilitate the procurement of local contractors and labor. On August 22, 2003 city ordinance number 03-10077 was approved by a 5 to 0 vote, authorizing a Redevelopment Agreement between the City and EnviRes. This ordinance provides for support for the HyMelt® project and for TIF funding in the amount of $2.45 million. On October 9, 2003 the East St. Louis Enterprise Community through its Economic Development Loan Program awarded $50,000 to EnviRes for use in the development of the project. To date, more than 40 local companies have submitted to EnviRes their qualifications to perform various tasks and contracts for the construction, operations and maintenance of the HyMelt® plant.

Task 1.1 Detailed Project Management Plan

EnviRes developed a detailed project management plan using Microsoft Project 2000. This plan contains 147 tasks and subtasks. EnviRes updates this plan on a monthly basis to reflect work completed, track progress and update any program changes. The plan is too large to conveniently fit in this report. EnviRes will make the project plan available to ICCI upon request as a Microsoft Project 2000 file, as a pdf file, or as a 42" X 60" paper chart.

Task 1.3 Predictive Modeling of HyMelt Process

MEFOS Modeling

EnviRes divided predictive modeling into two major areas. We decided that the first area should cover reactor chemistry including metal chemistry, slag chemistry and gas chemistry. We selected process modeling after the reactor as the second area.

We selected MEFOS to perform the reactor chemistry modeling. DOE funded contract costs for this part of the project, however EnviRes uses data from this work in other tasks. MEFOS uses the FactSage[5] system for this type of modeling. FactSage uses Gibbs Free Energy minimization to determine the thermodynamic equilibrium for all three phases simultaneously. MEFOS has an extensive FactSage database for metal, slag and gas phases.

MEFOS simulated the adiabatic behavior of the melt. Cooling of the melt due to sensible heat requirements and endothermic heats of reaction appear as melt temperature vs. coal injection time in Figure 2. The weight rate of carbon, hydrogen, nitrogen and chlorine in the feed appear at the top of each figure. Oxygen, sulfur and ash in the feed do not appear in the heading but comprise the balance of the feed to result in 10 kg/min. Heating of the melt during oxygen blowing appear as temperature vs. oxygen injection time in Figure 3.

The reader can see from these figures that the melt temperature would increase by approximately 255°C per cycle under adiabatic conditions. Heat losses will reduce this temperature rise. Steam injection or some other coolant will keep the melt at the desired temperature in commercial practice.

[5] Bale, C.W., Chartrand, P., Degterov, S.A., Eriksson, G., Hack, K., Mahfoud, R.B., Melancon, J., Pelton, A.D., and Petersen, S., "FactSage Thermochemical Software and Databases", CALPHAD 26(2):189-228.

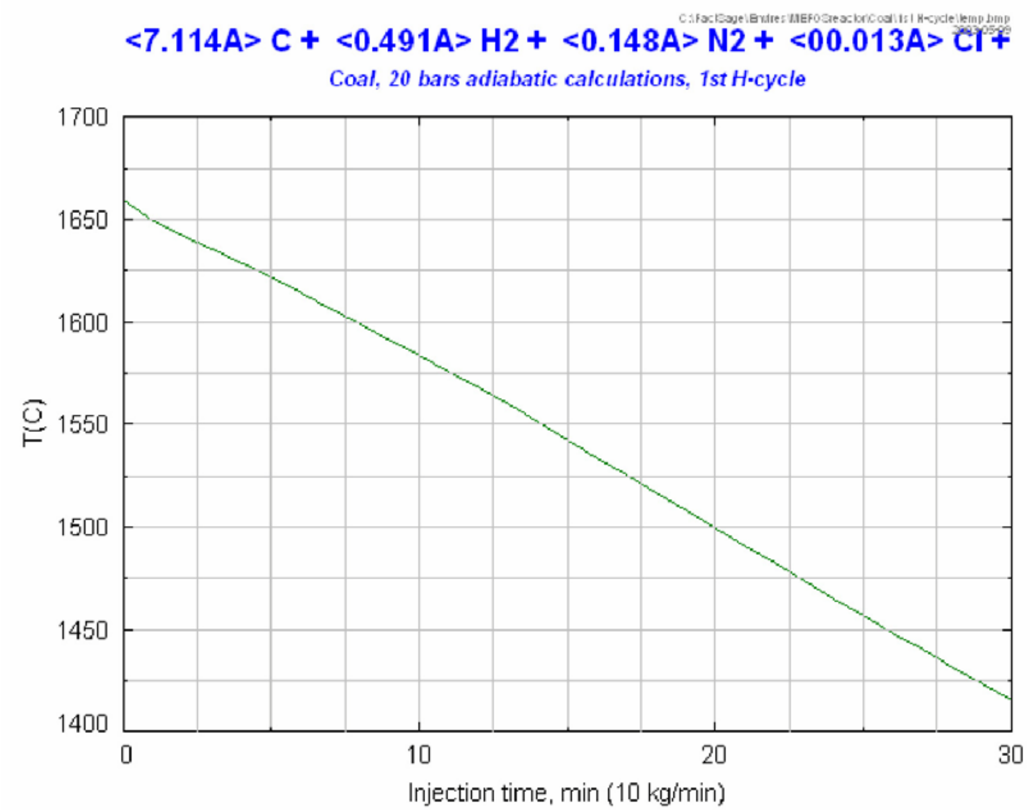

Figure 2. Melt temperature vs. coal injection time

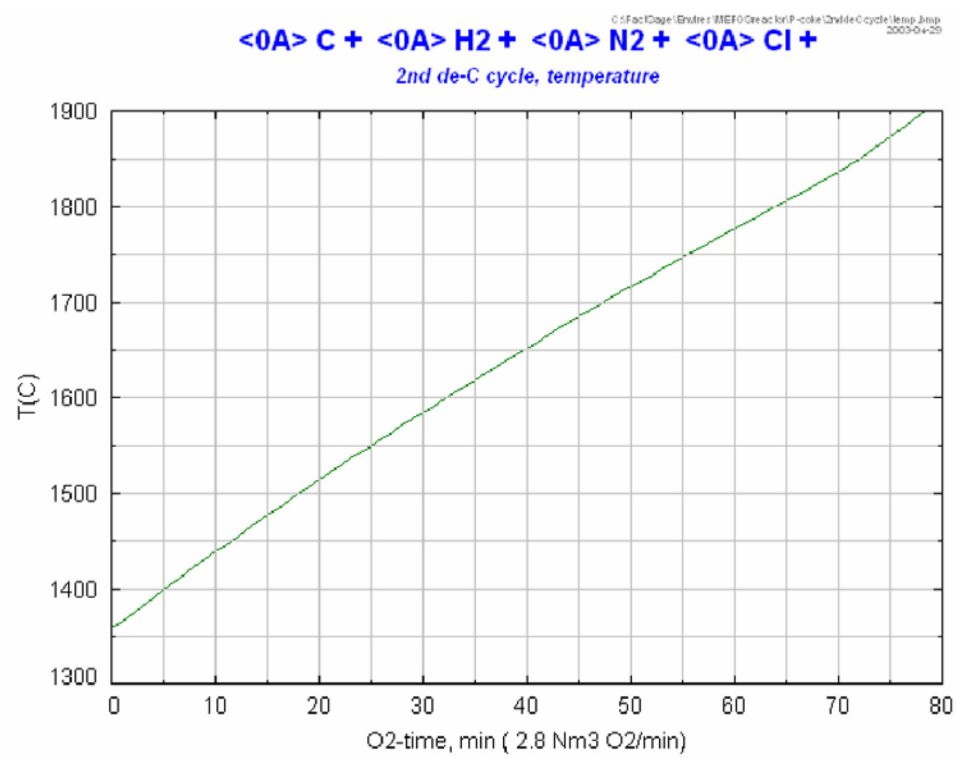

Figure 3. Melt temperature vs. oxygen injection time

Figure 4 shows the composition of the product gas stream during coal injection as a function of coal injection time. The composition shown in Figure 4 is cumulative. The instantaneous hydrogen composition would be much lower at first when carbon monoxide production from reacting with FeO is occurring (the first 5% of the cycle) and much higher later. Much of this carbon monoxide can be directed to the carbon monoxide header by proper valve timing resulting in higher overall hydrogen purity. MEFOS did not use any contained oxygen in the coal. Minor constituents such as methane, H2S, and nitrogen appear at the bottom of the figure. These constituents generally amount to less than 1% v. Illinois #6 coal is typically 8 to 9% oxygen; this would increase the carbon monoxide content in the hydrogen by 13 to 15%. Methane and nitrogen are each present at a level of approximately 1 to 2%. The simulation found HCN levels in the product gas to be approximately 300 ppm and COS levels to be approximately 4 ppm.

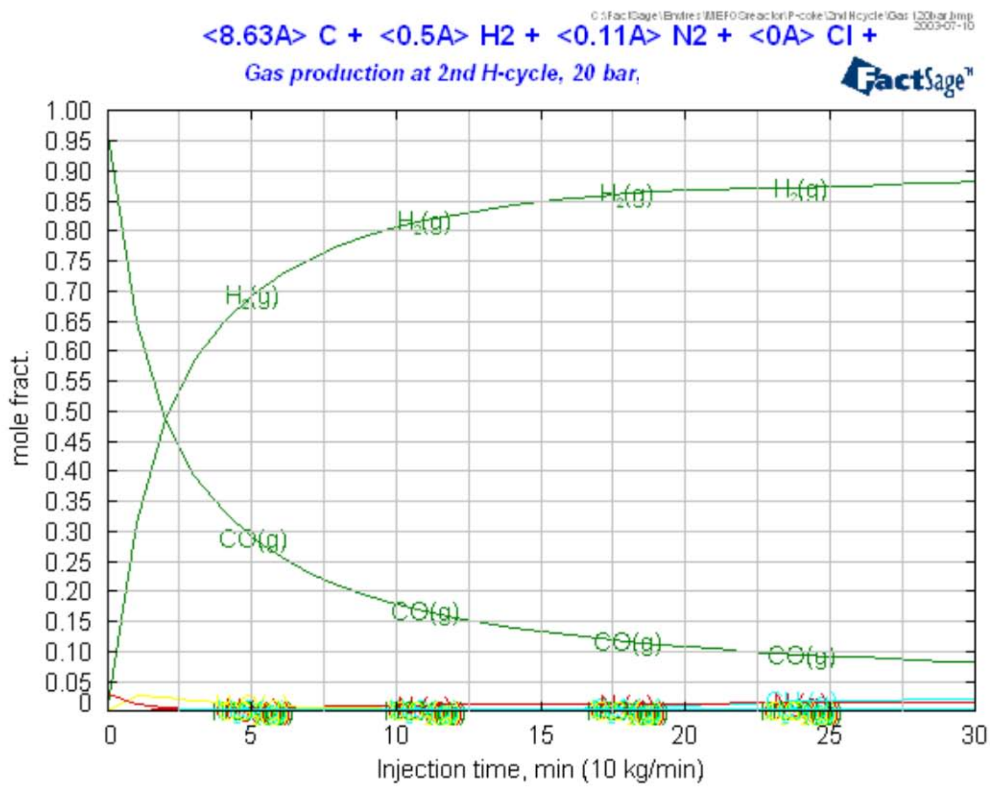

Figure 4. Product gas composition as a function of coal injection time.

The MEFOS simulation showed that 25 to 40 % of the feed sulfur could be removed as H_2S in the product gas. Lime additions can remove the remaining sulfur as CaS in the slag. Allowing the metal sulfur content to reach approximately 1%, producing H2S in the product gas (removing it later by amine scrubbing) and removing the remaining sulfur with lime is much more efficient than removing all of the sulfur with lime because the lime utilization factor (the fraction of CaO $\rightarrow$ CaS) is much higher. Sulfur removal by hydrogen recycle did not appear to be attractive.

Kvaerner Modeling

The work performed by Kvaerner was funded by ICCI. Kvaerner directed this work toward objective 2, developing a DBM and objective 3, assessing the economic impact of the HyMelt Process on hydrogen production on refinery operations. Kvaerner performed process simulations on the HyMelt process assuming a composition for the reactor effluent using the Aspen Plus process simulator. This was done to debug the simulation flowsheet. Kvaerner awaits results from atmospheric testing before performing detailed process and economic analysis. Figure 5 shows the Process flow diagram for the gasification section of the HyMelt process, Figure 6 depicts the water gas shift section and Figure 7 details the amine scrubing system that Kvaerner uses for the computational process flow simulation. Kvaerner could investigate the cost of shifting most of the carbon monoxide produced during decarburization because there is little doubt about the composition or flow rate of this stream. The amine system was also modeled. Kvaerner requested, received and incorporated into the model vendor input from UOP for the amine system.

Kvaerner worked with UOP to develop stream flows, compositions, pressures, temperatures, size equipment, develop capital cost and develop operating cost for PSA purification of the hydrogen rich stream produced by the HyMelt process. UOP quoted a purchase price of $1,700,000 for a skid mounted 15.31 MSCFD product H_2 PSA unit. UOP quoted a purchase price of $2,500,000 for a Skid mounted unit that processed 28.39 MSCFD product H2. In both cases the product H2 purity was 99.9%, the feed compositions were somewhat different. A summary of this work appears in Appendix I.

The stream flows and compositions for Figures 6 and 7 appear in Appendix I. The capital and operating cost summary for water gas shifting most of the CO produced by the above-described HyMelt plant appear in Tables 1 and 2. This simulation was based on a nominal 450 t/d plant which is rather small, however the differential cost between burning CO as fuel and shifting it to H_2 is $2.86 per 1000 scf. This is an unacceptably high cost under any circumstances. This study demonstrates the relatively high cost of water gas shift. HyMelt is one of the few coal gasification processes when used to make hydrogen where water gas shifting is an option not a requisite.

Kvarner will complete the remaining simulation work during the second quarter of 2004 under DOE funding. The DBM and refinery economic evaluation will also be completed under DOE funding. We expect the DBM and refinery economic evaluation to be completed in the third quarter of 2004. EnviRes will furnish ICCI with this information as it becomes available.

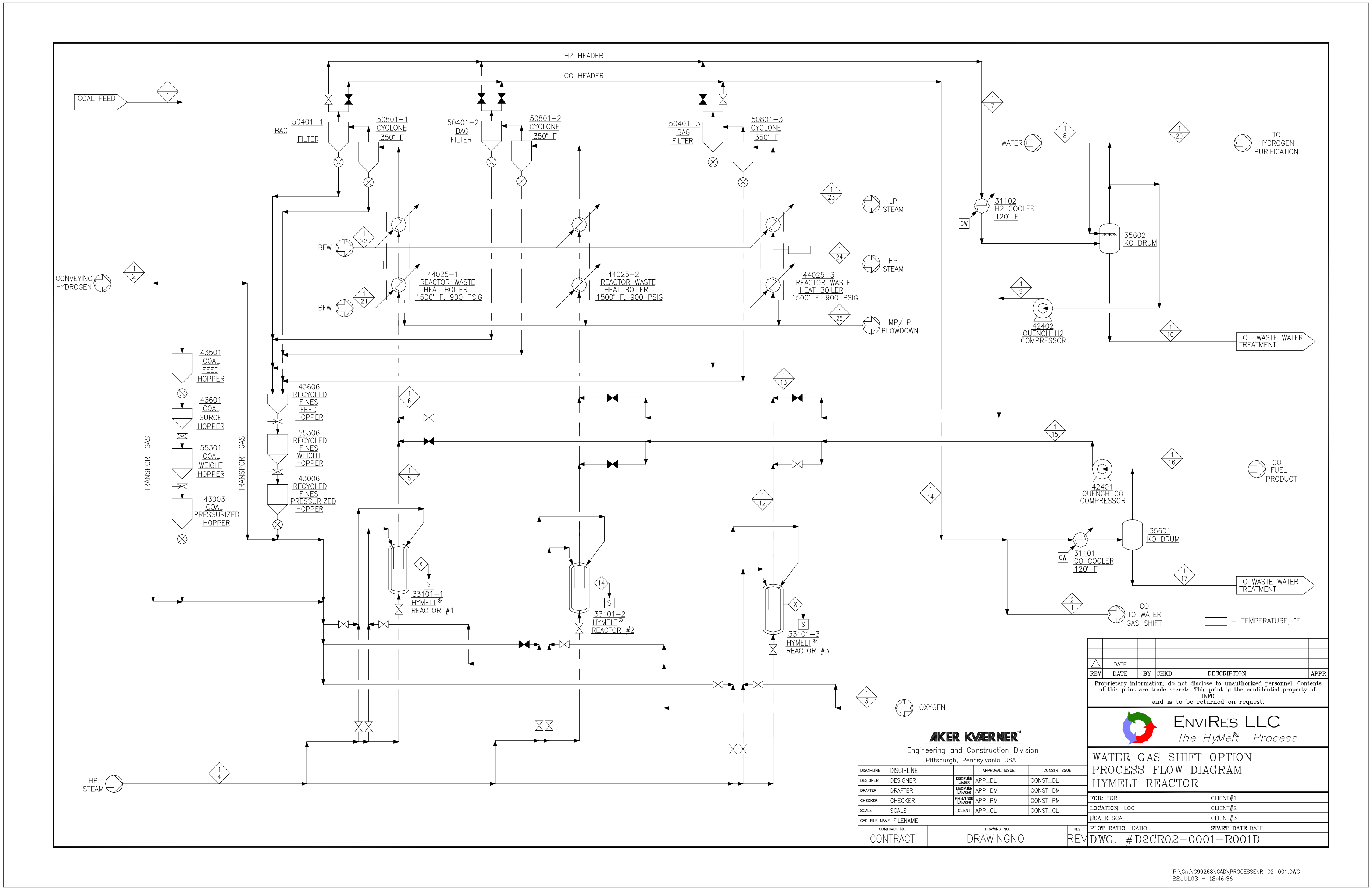

Figure 5. Process Flow Diagram for Gasification Section

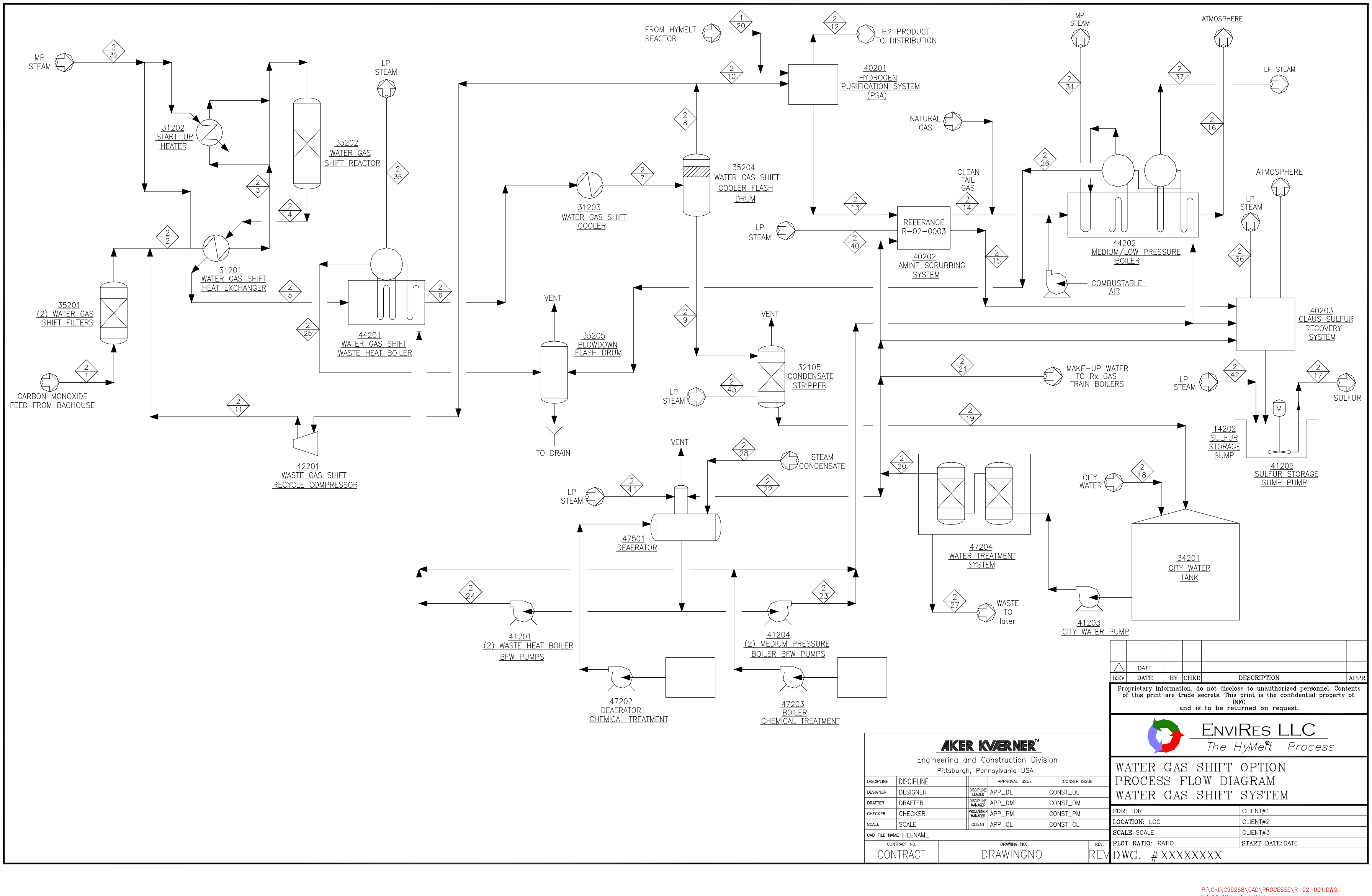

Figure 6. Process flow diagram for water gas shift study

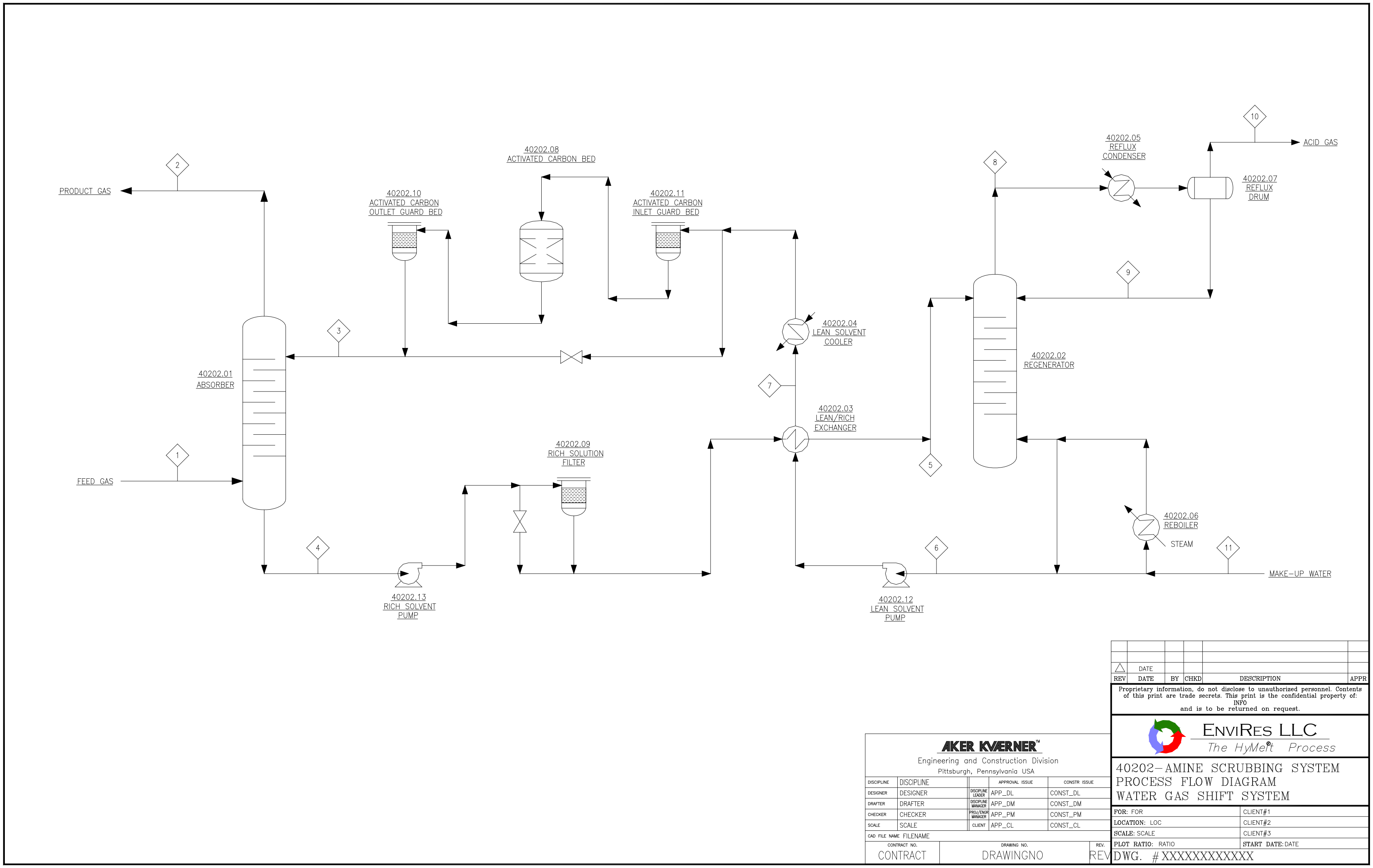

Figure 7. Process Flow Diagram for Amine Scrubbing System

Water Gas Shift Equipment List
C99268
EnviRes LLC HyMelt Process

Preliminary Economics of Water Gas Shift Option (Differential to Base Case)

Capital Cost Multiplier	1		Labor Rates (all-up):		
Basis:			Engineering	80	$/hr
Avg. On-stream Factor	90%		Field Labor	70	$/hr
Amortization Parameters			Constr. Mgt	85	$/hr
Annual Interest Rate	10%				
Payoff Period	20	years			

Estimated Differential Capital Costs:				
Major Equipment Cost	6,206,000			
Installed Equipment Cost	5,319,800	Field Hrs	49300	
Direct Totals	11,525,800			
Constr Equip & Indirects	$2,305,160	% Directs	20%	
Constr. Mgt. Staff Supv	$794,100	% Field Hrs	18.95%	9342
Freight	$366,520	% Directs	3.18%	
Taxes & Permits	$504,830	% Directs	4.38%	
Engineering	$2,545,600	Manhours	31820	
Other Project Costs (Ovhd & GA)	$1,342,339	% Above Indirects	20.60%	
Contingency	$3,420,768	% Total	15.00%	
Indirect Totals	$11,279,317			
Total Capital Cost	$22,805,117			

Table 1. Capital cost for water gas shift

Differential Operating & Maintenance Costs, $ per year:						
Natural Gas @ $ / MM Btu	5	$2,135,250	MM SCFD	1.3	Btu/SCF	1000
Electricity @ cents / kwh	0.04	$443,081	kwh	1405		
Cooling Water Chem @ cents/kgal	0.02	$122,990	gpm	13000		
BFW Chem @ cents/kgal	0.08	$12,488	gpm	330		
LP Stm (from Reactor) @ $ / k lb	0	$0	lb/hr consumed	14300		
Operation/ Maint @ $ / manhr	50000	$150,000	No. of addnl	3		
Insur & Taxes @ 1% Capital/yr		$228,051				
O & M Mgt Fees		$400,000				
Spare Parts @ 5% Major Equip/yr		$310,300				
Total O & M Cost		$3,802,161				
Amortization Cost @ % capital/ yr	11.75	$2,678,680				
Total Yearly Costs		6,480,841				
Differential Sales, $ per year:						
CO Fuel Lost @ $ / MM Btu	2.5	-$4,142,960	MM SCFD	-16.54	Btu/SCF	305
PSA TailGas Fuel Lost @ $ / MM Btu	1.5	-$648,459	MM SCFD	-3.76	Btu/SCF	350
Total Sales		-$4,791,419				
Net Hydrogen Production Cost, $ per year		$11,272,260				
Net Hydrogen Production Cost, $ per k scf	$	2.86	MM SCFD	12		

Table 2. Differential operating and net production cost for water gas shift

Task 1.2 Preparation and Shipment of Feedstock

EnviRes purchased 25 tons of Illinois #6 coal from Old Ben Coal Company's Zeigler #11 mine. EnviRes procured a common carrier to transport the coal to Empire Coke Co. in Holt AL where on November 9, 2002 it was pulverized, dried and loaded into 1-ton polypropylene bulk bags that EnviRes purchased. EnviRes arranged for delivery through Page and Jones of Mobile, AL of a sea-land container to Empire Coke. Approximately 19.3 tons of pulverized, dried coal in bulk bags were loaded into the container on November 12. The container was hauled by highway to Savannah, GA, loaded onto a ship on November 22, delivered to the port at Luleå, Sweden and transported by truck to MEFOS. The coal arrived in good condition at MEFOS on December 20.

Task 1.4 Combustion Analysis Modeling

EnviRes and Siemens Westinghouse Power Corporation decided to delay combustion analysis modeling until completion of atmospheric testing so that more accurate gas compositions for the fuel gas would be available. EnviRes and Siemens Westinghouse Power Corporation developed a specification document that identifies all significant parameters necessary to design a gas turbine for this fuel. EnviRes and Siemens Westinghouse will use this design as the basis for performing objective 4, modeling the cost of electrical power production. Appendix I contains a copy of this document and the initial reply from EnviRes to Siemens Westinghouse Power Corporation. We scheduled computational modeling to begin in the fourth quarter of 2003. EnviRes will complete this work under with DOE funding. EnviRes will furnish ICCI with this information as it becomes available.

Task 1.5 Design and Fabrication of Pilot Plant Specific Apparatus

DOE funded contract costs for this part of the project, however EnviRes uses data from this work in other tasks. MEFOS and EnviRes reviewed plans for preparation of the test facility on February 23 to 28, 2003. Much of the equipment in place was suitable for the upcoming test program. MEFOS relined the universal converter with a carbon-magnesia refractory; they installed a slit tuyere for bottom stirring in the bottom of the universal converter; we reviewed and found that the instrumentation and sampling systems were adequate; we found the oxygen lance and oxygen blowing system to be acceptable; we reviewed the data acquisition system and found it acceptable; we agreed that MEFOS should design and fabricate a new coal injection lance, Figure 6 and 7 show design details for this lance.

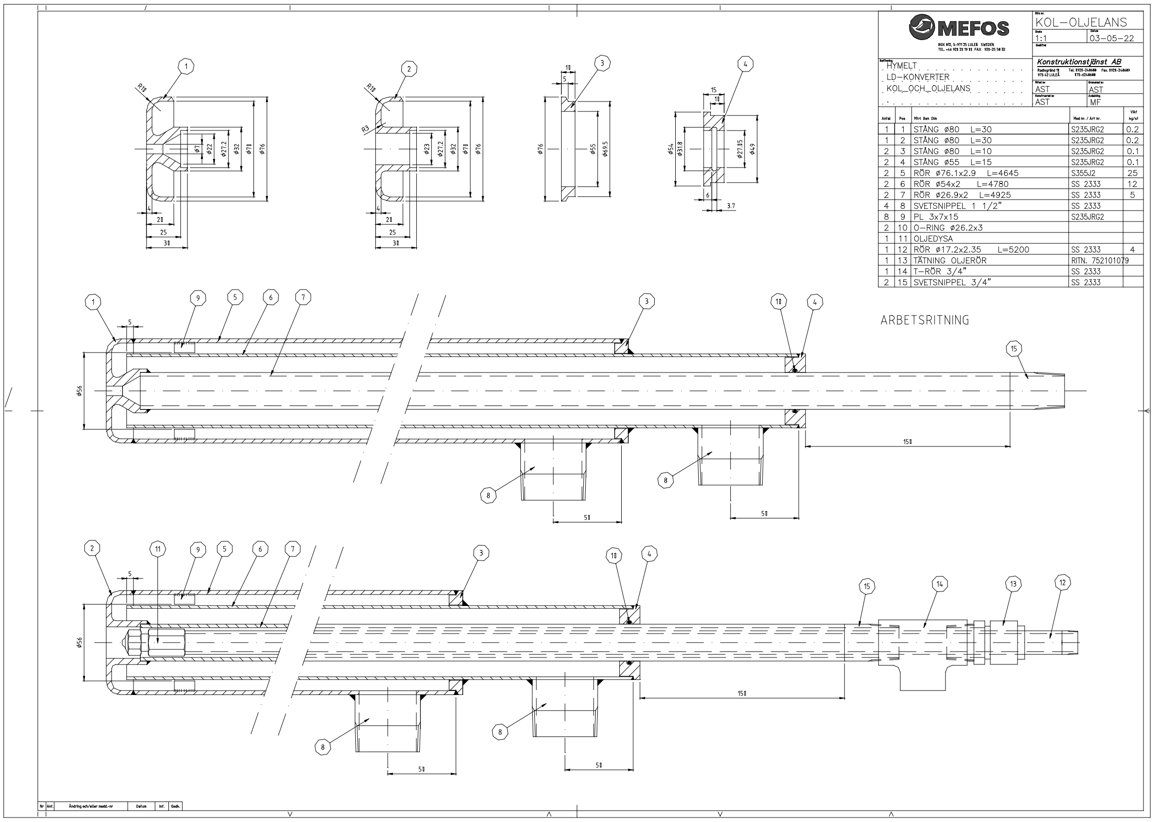

Figure 6, Design details of the coal injection lance

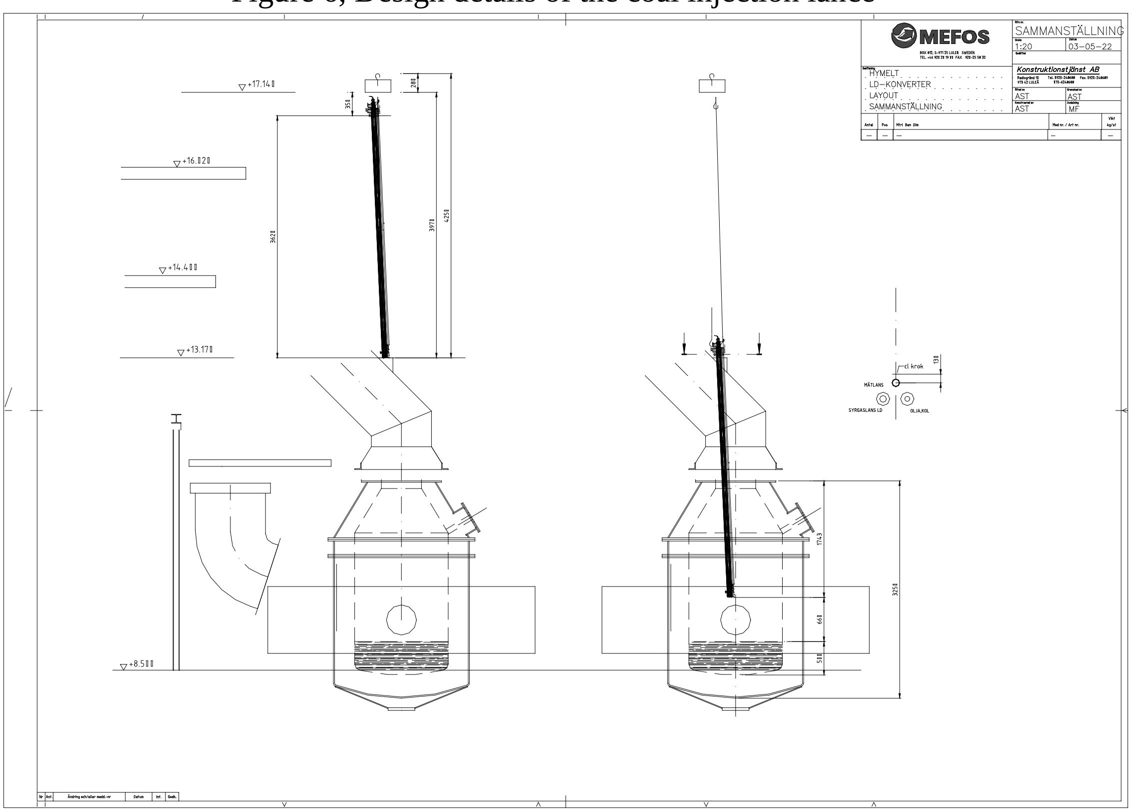

Figure 7, Lance insertion details

We agreed that MEFOS should acquire an online quadrapole mass spectrometer for more accurate product gas analysis when feeding coal. MEFOS moved an existing lock hopper for coal feeding from storage and installed it; Figure 8 shows the lock hopper after installation. We developed an experimental test plan. MEFOS scheduled testing for June 3 – 13, 2003.

Figure 8, Coal injection lock hopper

Task 2.1 Combustion Testing

EnviRes and Siemens Westinghouse Power Corporation (SWPC) evaluated diffusion and catalytic burners for use in gas turbines utilizing the carbon monoxide rich fuel gas from the HyMelt process. Table A1 in Appendix II lists advantages and disadvantages of these two types of burners. The diffusion burner is currently used in commercial combustion turbines using both natural gas and synthesis gas as fuel. The catalytic burner is currently under development by SWPC. The catalytic burner reduces NO_x emissions to 2 ppmv without SCR. EnviRes and SWPC agreed to model and test the catalytic burner on the condition that this would not preclude the use of diffusion burners in the event that catalytic burners could not be used with HyMelt fuel gas. EnviRes delayed starting combustion testing until after we complete task 1.4, Combustion Analysis Modeling. This task should begin in the first quarter of 2004 and will be completed with DOE funding. EnviRes believes that using catalytic burners will significantly reduce the cost of electrical power production using HyMelt fuel gas.

Task 2.2 Atmospheric Pressure Testing

DOE funded contract costs for this part of the project, however EnviRes uses data from this work in other tasks. On June 5, 2003 MEFOS charged 5,500 kg of pig iron to the universal converter. MEFOS performed five coal injections and six decarburizations on this day. The sample probe plugged rapidly with dust. The online analyzer indicated that the methane composition in the product gas was in excess of 4% much of the time. When the converter was tilted, unconverted carbon could be seen floating on the slag.

On June 6, 2003 MEFOS charged 5,700 kg of pig iron to the universal converter. They made five coal injections, one petroleum coke injection and seven decarburizations. MEFOS increased the melt temperature and kept the amount of slag and its viscosity to a minimum in the converter. The sample probe filters didn't clog as rapidly as before, indicating less dust production. Methane values again remained high, in the range of 5 to 7%.

On June 12, 2003 MEFOS charged 5,520 kg of pig iron to the universal converter. MEFOS performed four coal injections, three oil injections and eight decarburizations on this day. We saw similar methane values as previously seen, in the 5 to 7% range. We saw a similar rate of sample filter clogging.

MEFOS determined the fraction of carbon in the feed that reported to the metal. It is depicted in Figure 9. The reader should note that the oxygen in the coal will remove approximately 13 % of the carbon in the feed as CO. Figure 9 does not consider this but it is clear that the much of the carbon in the feed that could have dissolved in the metal did not dissolve in the metal. The carbon uptake of the metal seems to decrease significantly as the rate of feed increases. The lowest elevation possible for the coal injection lance was approximately 40 cm above the metal surface. We believe that the velocity of the injection solids and gas substantially dissipated before reaching the surface of the metal. EnviRes will make available to ICCI on request the complete 74 page MEFOS report for this test period as a pdf file. All raw data are also available.

MEFOS and EnviRes reviewed the results of these tests and concluded that the carbon dissolution in the metal was unacceptable. We decided to conduct tests with a submerged lance. MEFOS modified the equipment and generated a test plan. MEFOS scheduled testing for September 2-4, 2003. MEFOS performed the tests on that date. We are still awaiting most of the results of laboratory analysis, but indications from the online analyzers during these tests were that the carbon dissolution in the metal was much higher. The universal converter operated in heat balance over 3 cycles of injection and oxygen blowing in spite of the relatively high heat loss for the small size (compared to commercial vessels) vessel exacerbated by additional non-operating time caused by tilting the vessel after each injection for sampling. EnivRes will report results of the September testing as they become available.

Task 3.2 Develop HyMelt Design Basis Memorandum

The design basis memorandum (DBM) is defined as a document consisting of a conceptual engineering design for the use of the HyMelt process in a commercial-scale first-of-a-kind gasification plant and an appropriation-quality capital cost estimate for said plant with comparisons to other competive gasification plants. The DBM will incorporate the results of all prior testing and studies, i.e., all of the engineering information necessary to design a commercial-scale demonstration HyMelt plant. Work on this task began under this DCCA agreement and will be completed under DOE funding. EnviRes will furnish ICCI with this information as it becomes available.

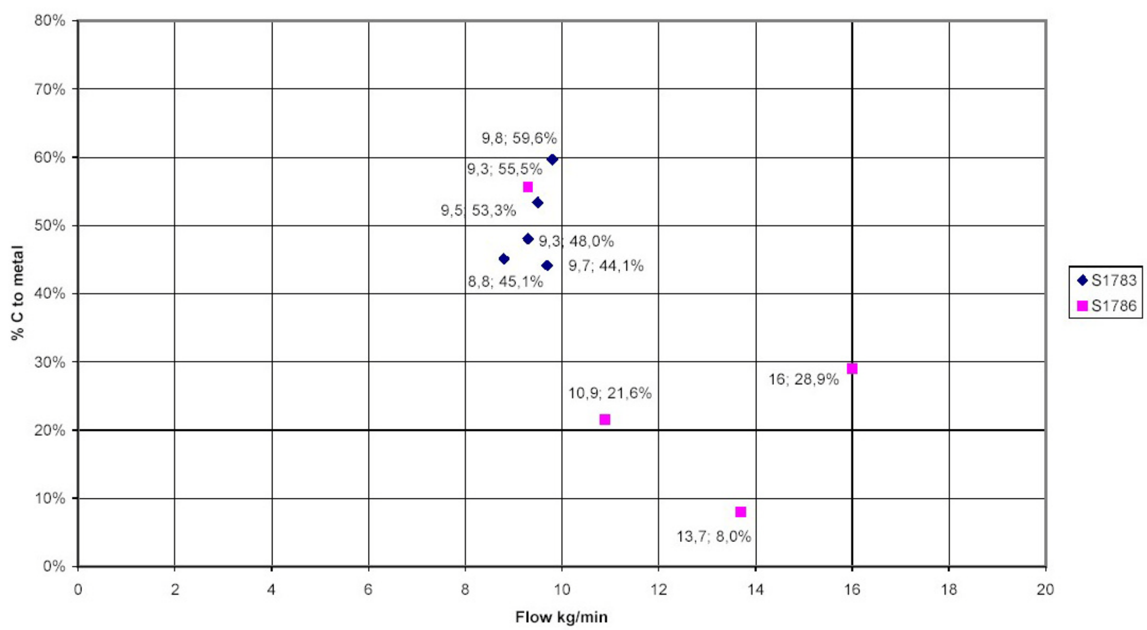

Figure 9. Carbon in the feed reporting to the metal.

CONCLUSIONS AND RECOMMENDATIONS

Coal injection using top entry lances does not appear to be feasible, at least with the type of lances that were available. Carbon dissolution rates in molten metal were well below that required for commercial operation. If lances with substantially higher velocity (say 1.5 Mach or higher) can be used with the nozzle closer to the metal surface and with a thinner, less viscous slag layer, top entry lance may become feasible. EnviRes and MEFOS do not plan to pursue better top entry lance design. Submerged lances (tuyeres) appear to give much better performance. If tuyere performance is adequate, some additional testing will be necessary to demonstrate that tuyeres can be successfully operated in a commercial mode of operation.

The HyMelt process operated in heat balance with a vessel as small as the universal converter.

Large scale testing of the HyMelt technology was accomplished at a fraction of the cost and in a much shorter time period by using the MEFOS facility. MEFOS should be considered by any one seeking to conduct large-scale gasification tests.

Based on thermodynamic simulations and preliminary test results the composition of the product gas from coal injection is close to expected values. When analytical results are completely available a more quantitative assessment can be made.

Kvaerner's preliminary study, the cost of water gas shifting CO to hydrogen appears to be prohibitively expensive. Kvaerner found the cost of incremental hydrogen over the fuel value of the CO consumed to be $2.86 per 1000 scf for a nominal 450 t/d. For larger plants the differential cost for hydrogen will decrease, but it seems unlikely that the differential cost will go below $1.25 per 1000 scf. EnviRes believes that the cost of converting CO by the water gas shift reaction has a significant impact on overall hydrogen economics. This work will be further developed in economic modeling of HyMelt hydrogen usage in refineries. We will continue to work with Kvaerner and Siemens Westinghouse to develop the design basis memorandum for a commercial scale plant and model the cost of electrical power production using HyMelt fuel gas.

UOP provided a capital cost for PSA purification of hydrogen that is similar to that used in preliminary cost estimates by EnviRes.

DISCLAIMER STATEMENT

This report was prepared by Donald P. Malone & EnviRes LLC with support, in part by grants made possible by the Illinois Department of Commerce and Economic Opportunity through the Office of Coal Development and the Illinois Clean Coal Institute. Neither Donald P. Malone & EnviRes LLC nor any of its subcontractors nor the Illinois Department of Commerce and Economic Opportunity, Office of Coal Development, the Illinois Clean Coal Institute, nor any person acting on behalf of either.

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APPENDIX I
KVAERNER WORK

SPECIALTY ALKANOLAMINES

Gas Treating Products

Products, Technology and Service from Dow

Date: 7/10/03

Tracking Number:	117USA0703
Customer:	AkerKvaerner PSA TGU
Plant/Project	
Location:	Pittsburgh
Technical Contact:	Jerry LaRosa
Sales Contact:	Eddy Garcia-Rameau
Customer Contact:	Jerry LaRosa
Customer Phone No:	412-918-3654
Customer E-mail Address:	Gerald.LaRosa@akerkvaerner.com
Project Number:	

Notes:

Special gasifying application that needs to treat PSA tail gas stream forClaus Plant. Gas Flowrate is 2425 lb mol/hr with 65.3% CO_2 and 0.865% H_2S. HS.-103 specified as solvent of choice.

Gas Treating Products

Products, Technology and Service from Dow

AkerKvaerner PSA TGU

Contents:	Page Number

AkerKvaerner PSA TGU

Simulation Summary

Absorber Feed Gas Conditions

Gas Flow Rate:	22.09	MM SCFD
Pressure:	5.00	Psig
Temperature:	110.0	Deg F

Composition	Feed Mol %	Feed LB MOL/HR	Product Mol%	Product LB MOL/HR
H2S	0.86%	20.98	0.00%	0.02
CO2	65.29%	1,583.19	60.56%	1,424.87
H2	20.10%	487.47	20.72%	487.44
CO	11.40%	276.52	11.75%	276.50
N2	1.02%	24.69	1.05%	24.69
CH4	0.75%	18.09	0.77%	18.09
C2H6	0.02%	0.58	0.02%	0.58
C3H8	0.05%	1.16	0.05%	1.16
H2O	0.51%	12.32	5.08%	119.47
UCARSOL	0.00%	0.00	0.00%	0.00
TOTAL	100.00%	2,425.00	100.00%	2,352.82

Treated Gas Conditions

GAS FLOW RATE:	21.43	MM SCFD
H2S	10	PPMV
CO2	63.8	%(V/V) DRY
CO2 Slippage	90.0	%

Solvent

Name	UCARSOL HS	103
Lean Solvent Flow	560.0	GPM
Amine Strength	50.00	%(W/W)
Internals - Number of Contact Trays	10	TRAYS

Solution Conditions

Lean Solvent Temperature	100.0	Deg F
Lean Loading	0.005	Mol/Mol
Rich Loading	0.159	Mol/Mol

Regenerator Conditions:

Tower Internals - Number of Trays	20	TRAYS
Rich Amine Feed Temp	213.3	Deg F
Reboiler Press	13.0	Psig
Reflux Flow	31.8	GPM

Exchanger Data:

Lean Cooler Duty	13.681	MM BTU/HR
Lean - Rich Exch'r	27.269	MM BTU/HR
Reflux Cond'r Duty	17.221	MM BTU/HR
Reboiler Duty	32.619	MMBTU/HR

AkerKvaerner PSA TGU

Major Equipment Summary

Absorber

Absorber Internals	10	TRAYS
Absorber Diameter	7.6	FT
Lean Loading	0.005	Mol/Mol
Rich CO2 Loading	0.141	Mol/Mol
Rich H2S Loading	0.019	Mol/Mol
Atmospheric Pressure	14.7	Psia
Treated Gas H2S	10.0	PPMV
Treated Gas CO2	63.8	%(V/V) DRY

Regenerator

Regenerator Internals	20	TRAYS
Regenerator Diameter	6.3	FT
O/H Reflux Ratio	5.00	Mol H2O/Mol AG
Regenerator Heat to Acid Gas Ratio	181.954	M BTU/Mol Acid Gas
Steam to Feed Ratio	1.077	LB/GAL

Reboiler

Heat Duty	32.619	MMBTU/HR	**U**	145.0	BTU/HR-FT2-DEGF
Steam Rate	35.8	M LB/HR	**LMTD**	41.8	Deg F
Reboiler Temperature	253.3	Deg F	**Fn**	1.00	
Reboiler Steam Pressure	50.0	Psig	**Area**	5,384	SQFT

Lean/Rich Exchanger

			U	120	BTU/HR-FT2-DEGF
Heat Duty	27.269	MM BTU/HR	**LMTD**	41.6	Deg F
Rich Inlet Temp	110.0	Deg F	**Fn**	0.80	
Rich Outlet Temp	213.3	Deg F	**Area**	6,836	SQFT
Lean Inlet Temp	253.3	Deg F			
Lean Outlet Temp	153.1	Deg F			

Lean Solvent Cooler

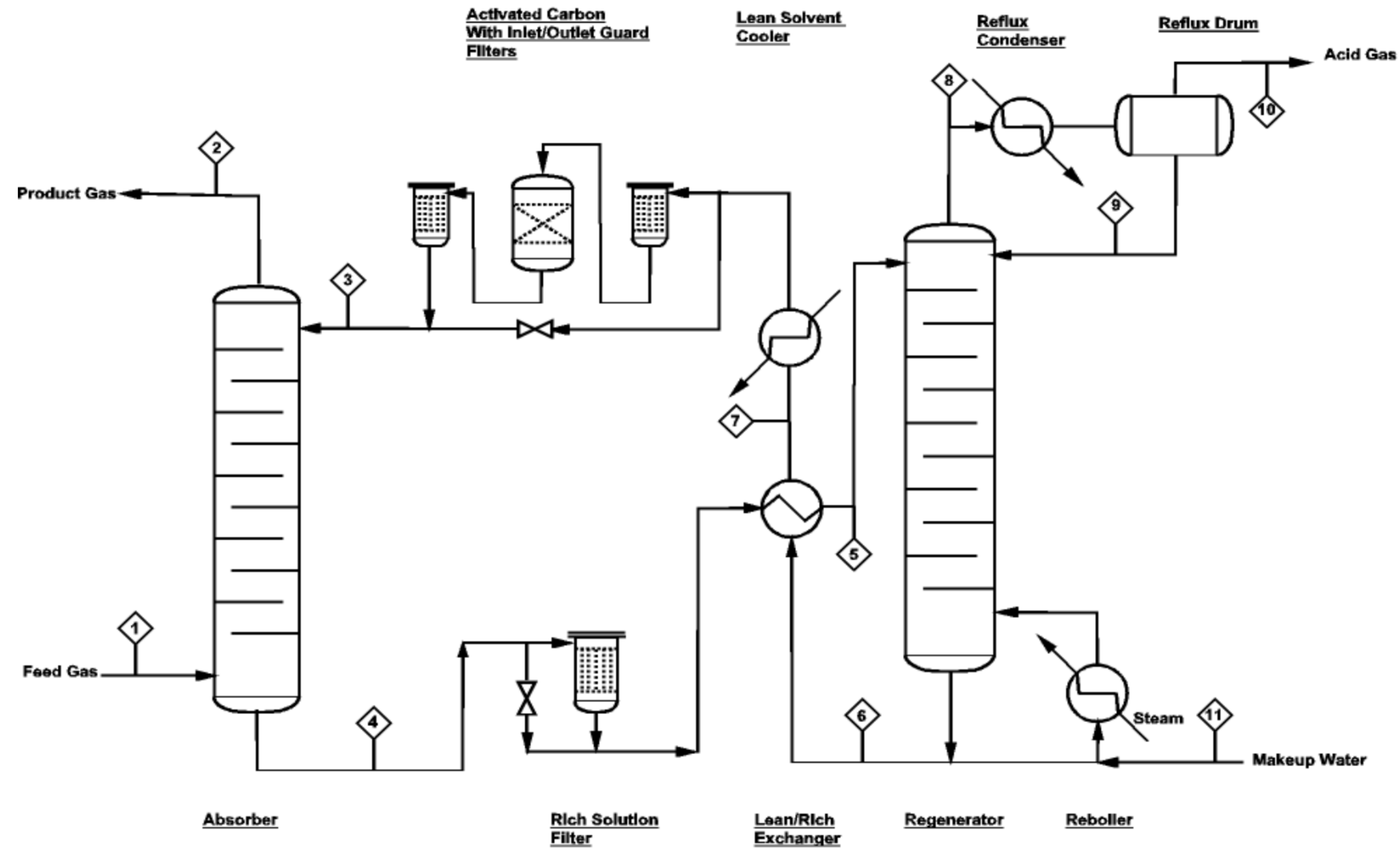
			U	90	BTU/HR-FT2-DEGF
Type	AIR		**LMTD**	15.4	Deg F
Heat Duty	13.681	MM BTU/HR	**Fn**	0.80	
Lean Inlet Temp	153.1	Deg F	**Area**	12,309	SQFT
Lean Outlet Temp	100.0	Deg F			

Reflux Condenser

			U	64	BTU/HR-FT2-DEGF
Type	AIR		**LMTD**	49.7	Deg F
Heat Duty	17.221	MM BTU/HR	**Fn**	0.80	
Inlet Temp	231.6	Deg F	**Area**	6,759	SQFT
Outlet Temp	120.0	Deg F			
Reflux Flow Rate	31.8	GPM			

AkerKvaerner PSA TGU

Stream Summary		Feed Gas 1	Product Gas 2	Lean UCARSOL 3	Cool Rich UCARSOL 4	Hot Rich UCARSOL 5	Hot Lean UCARSOL 6	Warm Lean UCARSOL 7	Stripper Overhead 8	Reflux Liquid 9
Temperature	Deg F	110.0	100.0	100.0	110.0	213.3	253.3	153.1	231.6	120.0
Pressure	Psig	5.0	4.0	4.0	5.0	.0	13.0		11.0	10.0
Gas Flow	MM SCFD	22.1	21.4						9.80	
Liquid Flow	GPM			560.0	573.2	-	594.4	570.4		31.8
Lean Solution Density	LB/GAL			8.8	8.7	8.4	8.3	8.6		8.7
Lean Solution Viscosity	cP			5.35			0.96	2.25		
Lean Solution Specific Heat	BTU/LB-F			0.858			0.956	0.889		
Lean Solution Surface Tension	DYNE/CM			38.8			30.3	35.9		
Lean Solution Thermal Conductivity	BTU/HR-FT-F			0.27			0.328	0.298		
H2S	LB MOL/HR	20.98	0.02	0.68	21.63	21.63	0.68	0.68	20.95	
CO2	LB MOL/HR	1,583.19	1,424.87	5.13	163.45	163.45	5.13	5.13	158.32	
H2	LB MOL/HR	487.47	487.44		0.03	0.03			0.03	
CO	LB MOL/HR	276.52	276.50		0.02	0.02			0.02	
N2	LB MOL/HR	24.69	24.69		0.00	0.00			0.00	
CH4	LB MOL/HR	18.09	18.09		0.00	0.00			0.00	
C2H6	LB MOL/HR	0.58	0.58		0.00	0.00			0.00	
C3H8	LB MOL/HR	1.16	1.16		0.00	0.00			0.00	
H2O	LB MOL/HR	12.32	119.47	8,184.82	8,077.67	8,077.67	8,184.82	8,184.82	896.36	883.17
UCARSOL HS	LB MOL/HR		0.003	1,161.02	1,161.02	1,161.02	1,161.02	1,161.02	0.379	0.379
TOTAL	LB MOL/HR	2,425.00	2,352.82	9,351.64	9,423.82	9,423.82	9,351.64	9,351.64	1,076.07	883.55
TOTAL	LB/HR	80,391.4	74,640.1	295,147.8	300,899.1	300,899.1	295,147.8	295,147.8	23,830.3	15,958.5
M/H A.G.	LB MOL/HR	1,604.16	1,424.89	5.81	185.08	185.08	5.81	5.81	179.27	



SPECIALTY ALKANOLAMINES

The Dow Chemical Company
Process Flow Diagram

AkerKvaerner PSA TGU

Usim 4.0

Water Gas Shift Material Balance

Balance14Jul03.xls

C99168 PRELIMINARY MATERIAL BALANCE - Water Gas Shift Option

Stream Number	2-1	2-2	2-3	2-4	2-5	2-6	2-7	2-8	2-9	2-10	2-11	2-12	2-13				
Description	COFEED	HTRIN1	COFEED2	WGOUT	WHBIN	WGWHB OUT	FLASHIN	FLASHOUT	FLCOND	WGSOUT	REC	PSAPROD	TAILGAS			Convey. H2	H2 PRODUCT
Temperature F	350	192.4	600	842.5	694.9	390.3	120	120	120	119.9	126.1	130	110			130	130
Pressure psia	500	500	497	496	493	490	487	486	486	485	500	475	19.7			475	475
Vapor Frac	1	1	1	1	1	1	0.646	1	0	1	1	1	1			1	1
Mole Flow lbmol/hr	1816.315	5537.209	10912.55	10912.55	10912.55	10912.55	10912.553	7045.592	3866.961	3324.701	3720.891	2994.447	2424.883			1400	1594.447
Mass Flow lb/hr	51524.224	139485.15	236323.5	236323.5	236323.5	236323.5	236323.49	166555.9	69767.546	78595.05	87960.9	6038.129	80368.87			2823.019	3215.111
Volume Flow cuft/hr	32111.641	77404.455	245686	307933	273443.6	197321.5	89632.643	88311.34	1503.461	41755.83	45844.97	40665.93	750683.8			19012.626	21653.31
Enthalpy MMBtu/hr	-91.849	-402.652	-921.167	-921.125	-936.191	-966.694	-1065.708	-588.848	-476.859	-277.868	-310.803	1.136	-282.267			0.531	0.605
Mole Flow lbmol/hr																	
CO	1702.668	1925.713	1925.713	422.348	422.348	422.348	422.348	422.347	0.001	199.299	223.048	0.028	276.508			0.013	0.015
H2	25.356	1736.241	1736.241	3239.606	3239.606	3239.606	3239.606	3239.594	0.012	1528.712	1710.882	2994.375	487.456			1399.966	1594.409
H2O	3.051	16.546	5391.891	3888.525	3888.525	3888.525	3888.525	25.552	3862.973	12.058	13.495	0	12.326			0	0
CH4	0.163	0.346	0.346	0.346	0.346	0.346	0.346	0.346	0	0.163	0.183	0.018	18.098			0.008	0.01
C2H2	0.272	0.577	0.577	0.577	0.577	0.577	0.577	0.577	0	0.272	0.305	0	0.584			0	0
N2	1.108	2.348	2.348	2.348	2.348	2.348	2.348	2.348	0	1.108	1.24	0.025	24.673			0.012	0.013
CO2	83.55	1855.13	1855.13	3358.495	3358.495	3358.495	3358.495	3354.521	3.974	1582.944	1771.577	0	1583.099			0	0
H2S	0.031	0.065	0.065	0.065	0.065	0.065	0.065	0.064	0.001	0.03	0.034	0.002	20.974			0.001	0.001
COS	0.114	0.242	0.242	0.242	0.242	0.242	0.242	0.242	0	0.114	0.128	0	0.12			0	0
HCN	0	0	0	0	0	0	0	0	0	0	0	0	1.043			0	0
HG	0	0	0	0	0	0	0	0	0	0	0	0	0.001			0	0
*** VAPOR PHASE ***																	
Enthalpy Btu/lb	-1782.636	-2886.704	-3897.905	-3897.728	-3961.479	-4090.553	-3535.439	-3535.439		-3535.446	-3533.423	188.158	-3512.138			188.158	188.158
Heat Cap Btu/lb-R	0.261	0.327	0.415	0.436	0.429	0.421	0.36	0.36		0.36	0.361	3.448	0.254			3.448	3.448
Conductivity Btu-ft/hr-sqf	0.022	0.035	0.041	0.065	0.058	0.042	0.039	0.039		0.039	0.04	0.112	0.021			0.112	0.112
Density lb/cuft	1.605	1.802	0.962	0.767	0.864	1.198	1.89	1.886		1.882	1.919	0.148	0.107			0.148	0.148
Viscosity cP	0.024	0.019	0.024	0.029	0.027	0.02	0.017	0.017		0.017	0.017	0.01	0.016			0.01	0.01
VVSTDMX @ 60 F MMcuft/day	16.543	50.432	99.389	99.389	99.389	99.389	99.389	64.170		30.281	33.889	27.273	22.085			12.751	14.522
*** LIQUID PHASE ***																	
Enthalpy Btu/lb							-6834.935		-6834.971								
Heat Cap Btu/lb-R							1.146		1.146								
Conductivity Btu-ft/hr-sqf							0.335		0.335								
Density lb/cuft							46.404		46.405								
Viscosity cP							0.564		0.564								
Surface Ten dyne/cm							68.034		68.036								
Flowrate gpm																	

C99168 PRELIMINARY MATERIAL BALANCE - Water Gas Shift Option

Stream Number	2-14	2-15	2-16	2-17 *	1-20		2-18	2-19	2-20	2-21	2-22	2-23	2-24	2-25	2-26	2-27	2-28
Description	CLEAN TAIL GAS	CLAUS FEED	BOILER FLUE	SULFUR PRODUCT	H2FEED		CITY WATER	STRIPPED COND	DEMIN MAKE-UP	DEMIN TO Rx GAS TRAIN BOILERS	DEMIN TO WGS BOILERS	MED PRES BFW	WATER GAS SHIFT WHB BFW	WATER GAS SHIFT WHB BDOWN	MED PRES BDOWN	DEMIN PLANT WASTE	STEAM COND RETURN
Temperature F	100	120	465		120		60	212	100	100	100	250	250	308	474	100	298
Pressure psia	18.7	24.7	14.7		500		90	15	65	65	65	715	215	75	535	65	65
Vapor Frac	1	1	1		1		0	0	0	0	0	0	0	0	0	0	0
Mole Flow lbmol/hr	2352.714	192.502	6520		2094.63		2006.97	4219.37	6164.08	856.73	5187.01	6097.81	1772.97	17.76	120.34	62.26	1985.57
Mass Flow lb/hr	74618	7919	204170	670	7811.948		36155	76012	111046	15434	93444	109852	31940	320	2168	1122	35770
Volume Flow cuft/hr					26584.86												
Enthalpy MMBtu/hr					-3.749												
Mole Flow lbmol/hr																	
CO	276.489	0.019			77.237												
H2	487.427	0.029			1953.119												
H2O	119.470	13.190	928.77		0.268		2006.97	4219.37	6164.08	856.73	5187.01	6097.81	1772.97	17.76	120.34	62.26	1985.57
CH4	18.098	0.000			17.953												
C2H2	0.584	0.000			0.312												
N2	24.673	0.000	3505.48		23.59												
CO2	1424.789	158.310	1872.48		0.155												
H2S	0.021	20.953	SO2 - 22 ppmv		20.946												
COS	0.120	0.000			0.006												
HCN	1.043	0.000			1.043												
HG	0.001	0.000			0.001												
*** VAPOR PHASE ***																	
Enthalpy Btu/lb					-479.868												
Heat Cap Btu/lb-R					1.877												
Conductivity Btu-ft/hr-sqf					0.099												
Density lb/cuft					0.294												
Viscosity cP					0.011												
VVSTDMX @ 60 F MMcuft/day	21.428	1.753	59.383		19.077												
*** LIQUID PHASE ***																	
Enthalpy Btu/lb																	
Heat Cap Btu/lb-R																	
Conductivity Btu-ft/hr-sqf																	
Density lb/cuft							62.37	59.81	62	62	62	58.8	58.8	50.2	55	62	55.6
Viscosity cP																	
Surface Ten dyne/cm																	
Flowrate gpm							72.3	158.6	223.5	31.1	188.1	233.2	67.8	0.8	4.9	2.3	80.3

C99168 PRELIMINARY MATERIAL BALANCE - Water Gas Shift Option

Stream Number		2-31	2-32		2-35	2-36 *		2-37		2-40 *	2-41	2-42 *	2-43				
Description		SUPHT MPSTM	MPSTM TO PROCESS		LPSTM from WHB	LPSTM from Claus	LPSTM from Rx gas trains	LPSTM from Med Pres Boiler		LPSTM to Amine Plant	LPSTM to Deaerator	LPSTM to Sulfur Pit	LPSTM to Condensate Stripper	LPSTM to Rx gas train deaerator		NG to BOILER	
Temperature F		700	700		308	308	308	308		298	298	298	298	298		20	
Pressure psia		520	520		75	75	75	75		65	65	65	65	65		50	
Vapor Frac		1	1		1	1	1	1		1	1	1	1	1		1	
Mole Flow lbmol/hr		5375.41	5375.43		1755.20	194.28	814.99	407.77		1985.57	720.40	83.26	360.81	22.20		142.63	
Mass Flow lb/hr		96838	96838.34		31620	3500	14682	7346		35770	12978	1500	6500	400		2580	
Volume Flow cuft/hr			121088														
Enthalpy MMBtu/hr			-533.581														
Mole Flow lbmol/hr																	
CO			0														
H2			0														
H2O		5375.41	5375.43		1755.20	194.28	814.99	407.77		1985.57	720.40	83.26	360.81	22.20			
CH4			0														
C2H2			0														
N2			0														
CO2			0														
H2S			0														
COS			0														
HCN			0														
HG			0														
*** VAPOR PHASE ***																	
Enthalpy Btu/lb			-5510.013														
Heat Cap Btu/lb-R			0.566														
Conductivity Btu-ft/hr-sqf			0.032														
Density lb/cuft			0.8														
Viscosity cP			0.023														
VVSTDMX @ 60 F MMcuft/day																1.299	
*** LIQUID PHASE ***																	
Enthalpy Btu/lb																	
Heat Cap Btu/lb-R																	
Conductivity Btu-ft/hr-sqf																	
Density lb/cuft																	
Viscosity cP																	
Surface Ten dyne/cm																	
Flowrate gpm																	

July 9, 2003

Email: mike.friedrich@akerkvaerner.com

Mr. Mike Friedrich
Aker Kvaerner
1200 Penn Avenue
Pittsburgh, PA 15222

SUBJECT: UOP Polybed PSA Unit
Envires, Kentucky
UOP Proposal P3H038 Rev. 4

Dear Mike,

In reply to your request, two budgetary designs and price estimates are provided for a UOP Polybed PSA Unit that produces a hydrogen product for the Hymelt Process.

Case 1 produces 15.31 MMSCFD of product hydrogen and Case 2 produces 28.39 MMSCFD of product hydrogen.

If there are any questions, please contact me at 713-744-2863 or email: Eugene.kuchta@uop.com.

Sincerely,

Eugene Kuchta
Process Technology & Equipment

EAK:rk

UOP POLYBED™PSA UNIT
for
Kvaerner
Envires / Hymelt Process

Project No: P3H038 July 9, 2003

Case 1 : 15.31 MM SCFD Product

		Feed	Product		Tail Gas	
Flowrate,	MM SCFD	19.08	15.31		3.76	
	lb-mol/hr	2,095	1,681		413	
Pressure,	psig	500	490		5	(Ex ST)
Temperature,	°F	120	130		110	
	°C	49	54		43	
Composition, mol%						
Hydrogen		93.24	99.9		66.15	
Nitrogen		1.13	Balance		5.32	
Carbon Monoxide		3.69	10	ppmv	18.70	
Carbon Dioxide		0.01	--		0.05	
Methane		0.86	Balance		4.36	
Acetylene		0.01	--		0.05	
Water		0.01	--		0.05	
Hydrogen Sulfide		1.00	--		5.07	
Hydrogen Cyanide		0.05	--		0.25	

Design Hydrogen Recovery: 86%

PSA Price (± 20% FCA USA. Shop): $1,700,000 USD

PSA Approximate Plot Size: 50 ft. x 30 ft.

PSA Utilities:

Instrument Air	1,400 SCFH @ 85 psig
Electric Power	5.0 kW @ 120 VAC, 1 ph, 60 Hz
Nitrogen (Startup only)	
Leak Test	120,000 SCF @ 500 psig
Purge	60,000 SCF @ 85 psig

UOP POLYBED™PSA UNIT
for
Kvaerner
Envires / Hymelt Process

Project No: P3H038 July 9, 2003

Case 2 : 28.39 MM SCFD Product

		Feed	Product		Tail Gas	
Flowrate,	MM SCFD	46.19	28.39		17.80	
	lb-mol/hr	5,072	3,118		1,954	
Pressure,	psig	491	481		5	(Ex ST)
Temperature,	°F	120	130		110	
	°C	49	54		43	
Composition, mol%						
Hydrogen		71.40	99.9		25.94	
Nitrogen		0.60	Balance		1.40	
Carbon Monoxide		5.20	10	ppmv	13.49	
Carbon Dioxide		21.70	--		56.31	
Methane		0.40	Balance		1.04	
Water		0.20	--		0.52	
Hydrogen Sulfide		0.40	--		1.04	
Hydrogen Cyanide		0.10	--		0.26	

Design Hydrogen Recovery: 86%

PSA Price (± 20% FCA USA Shop): $2,500,000 USD

PSA Approximate Plot Size: 70 ft. x 40 ft.

PSA Utilities:

Instrument Air		3,400 SCFH @ 85 psig
Electric Power		5.0 kW @ 120 VAC, 1 ph, 60 Hz
Nitrogen (Startup only)		
	Leak Test	360,000 SCF @ 491 psig
	Purge	180,000 SCF @ 85 psig

UOP POLYBED™PSA UNIT
for
Kvaerner
Envires / Hymelt Process

Project No: P3H038 July 9, 2003

UOP Scope of Supply includes	Adsorber Vessels Off-Gas Drum(s) Valve and Piping Skid Initial Adsorbent Charge Engineering Control Panel with CRT Relief Valves for Adsorber Vessels and Off-Gas Drum Block Valves Interconnecting Piping from Adsorber Vessels to Skid
Customer Scope of Supply includes but is not limited to	Foundation including Anchor Bolts Installation of All UOP Supplied Equipment Piping from Valve and Piping Skid to Off-Gas Drum Adsorbent Loading Under UOP Supervision Performance Test Piping To/From PSA Battery Limits Wiring between Skid and Control Cabinet/CRT Supply of Utilities Leak and Pressure Test of the PSA Unit Design and Supply of Peripheral Controls - Product Back Pressure Control Valve - Feed KO Drum - Feed Flow Control - Block Valves on All Piping To/From Unit - Feed and Tail Gas Vent - Tail Gas Flow/Pressure Control Analyzer Finish Paint

Notes:

1. The price is quoted exclusive of taxes, crating, insurance, or freight costs, and is based upon UOP standard fabrication and third quarter, 2003, costs.
2. The typical U.S. installation cost for Polybed™ PSA Units similar to the proposed system has been approximately 15% of UOP's quoted purchase price.

APPENDIX II

Gas Turbine Issues, Options and Resolutions

GAS TURBINE ISSUES, OPTIONS, AND RESOLUTIONS

This document describes the issues, alternatives, and decisions that define the functional specification of the gas turbine operating with HyMelt off-gas.

This is intended to be a working document that can be updated throughout the project by members of the project team. Siemens Westinghouse will maintain this document as a clearinghouse for questions and answers and a record of the technical dialogue related to gas turbine design parameters for this project.

The issues are listed in the Table of Contents. The group in [brackets] has primary responsibility for resolving each issue.

Contents

Revisions

Rev.	Date	Description of Change
A	6 Feb 03	Original Issue
B	29 July 03	Added HP, IP, and LP Steam Requirements

Syngas Compositions [EnviRes]

What are the composition (including trace compounds), temperature, and pressure of HyMelt syngas from Illinois #6 Coal and petcoke?

The coal-derived syngas composition below was estimated in the year 2000. Are those volume fractions still valid? What is the composition for petcoke-derived syngas?

Table 3
Syngas Composition

	Illinois #6 Coal Syngas	Petcoke Syngas	
Main gases			
CH_4	0.07		%(vol)
CO	75.72		%(vol)
CO_2	3.92		%(vol)
H_2	19.96		%(vol)
H_2O	0.30		%(vol)
N_2	0.03		%(vol)
Total	100.00		%(vol)
LHV	298		Btu/scf
LHV	11.76		MJ/Nm^3
Contaminants			
Barium (Ba)			Ppmw
Calcium (Ca)			Ppmw
Chlorides (Cl)			Ppmw
Copper (Cu)			Ppmw
Iron (Fe)			Ppmw
Lead (Pb)			Ppmw
Magnesium (Mg)			Ppmw
Manganese (Mn)			Ppmw
Nickel (Ni)			Ppmw
Phosphorus (P)			Ppmw
Potassium (K)			Ppmw
Silica (SiO2)			Ppmw
Silicon (Si)			Ppmw
Sodium (Na)			Ppmw
Vanadium (V)			Ppmw
Zinc (Zn)			Ppmw
Other trace metals			Ppmw

Emission Standards [EnviRes]

What are the emission standards for the proposed plant site?

Emission standards depend on plant location and are generally independent of fuel type.

In the near future, stack emissions are projected to be as low as 2 ppmv NOx and 2 ppmv CO when corrected to 0% moisture and 15% oxygen. These projections are based on (1) current limits in California, Massachusetts, New York, and New Hampshire of 2.5 to 3.5 ppmv NOx, (2) the fact that the current best available emission control technology (BACT) can achieve 2 ppmv for both NOx and CO, and (3) expectations that the limits will not be relaxed during the next 15 years.

The gas turbine exhaust may contain NOx and CO emissions higher than the projected plant emission limits, but other methods can be added to achieve acceptable emission levels at the stack exit. Alternatives for NOx mitigation include steam injection, water injection, and the addition of exhaust gas treatment, such as selective catalytic reduction.

Gas Turbine Sizes [EnviRes & SWPC-Orlando]

How many of which model of gas turbine will be used?

The original proposal assumed that the HyMelt® process module would produce about 1157 million Btu/hr of CO-rich gas, which was slightly less than the fuel requirements of a W501D5A gas turbine. The actual gasification module may produce more gas, which would match the fuel requirements of a larger turbine or turbines.

As a starting point, Table 2 lists the approximate syngas consumption of the three W-class gas turbines in 1x1 and 2x1 combined cycle arrangements.

Table 2
Estimated Gas Turbine Syngas Consumption

Combined Cycle Plant Designation	Gas fuel, Million Btu/h	Syngas, Million scf/h[1]	Gas Turbine Power, MW	Combined Cycle Power, MW
1x1.W501D5A	1,169	3.9	121	173
1x1.W501FD	1,726	5.8	190	283
1x1.W501G	2,146	7.2	253	365
2x1.W501D5A	2,338	7.8	241	346
2x1.W501FD	3,452	11.6	379	567
2x1.W501G	4,292	14.4	506	730

[1] Estimated consumption of syngas with an LHV of 298 Btu/scf.

Natural gas could be blended with the syngas at the gas turbine to compensate for reduced syngas flow to the gas turbine due to increased hydrogen production from the HyMelt plant.

Use of Natural Gas [EnviRes]

Will natural gas be used for either startup, blending, or both?

Gas turbines in IGCC plants normally start on natural gas, then switch (while running) to syngas. Also, natural gas can be blended with natural gas to compensate for reduced syngas flow due to increased hydrogen production from the HyMelt plant.

It would be good to confirm, however, that the presence of a natural gas line would not diminish the political appeal of a plant that is supposed to be a “coal-only” plant.

Syngas Supply Pressure [SWPC-Orlando and EnviRes]

What is the required syngas supply pressure for the gas turbine?

The syngas supply pressure allows proper operation of flow control valves. Fuel supply pressures may be 50 to 250 psi (3.5 to 17.5 bar) above the turbine pressure, depending on the selected fuel delivery system.

Gas Turbine	Pressure ratio	Syngas supply pressure
W501D5A	14.2	260 – 460 psia
W501FD	17.0	270 – 470 psia
W501G	19.2	330 – 530 psia

Syngas Supply Temperature [SWPC-Orlando and EnviRes]

What is the required syngas supply temperature for the gas turbine?

The temperature of the syngas entering the gas turbine burner should be hot enough that all condensable gases, including moisture, have at least 50 ^{o}F (28 ^{o}C) of superheat. Minimum gas temperatures related to moisture condensation are shown in Figure 1 for various moisture contents.

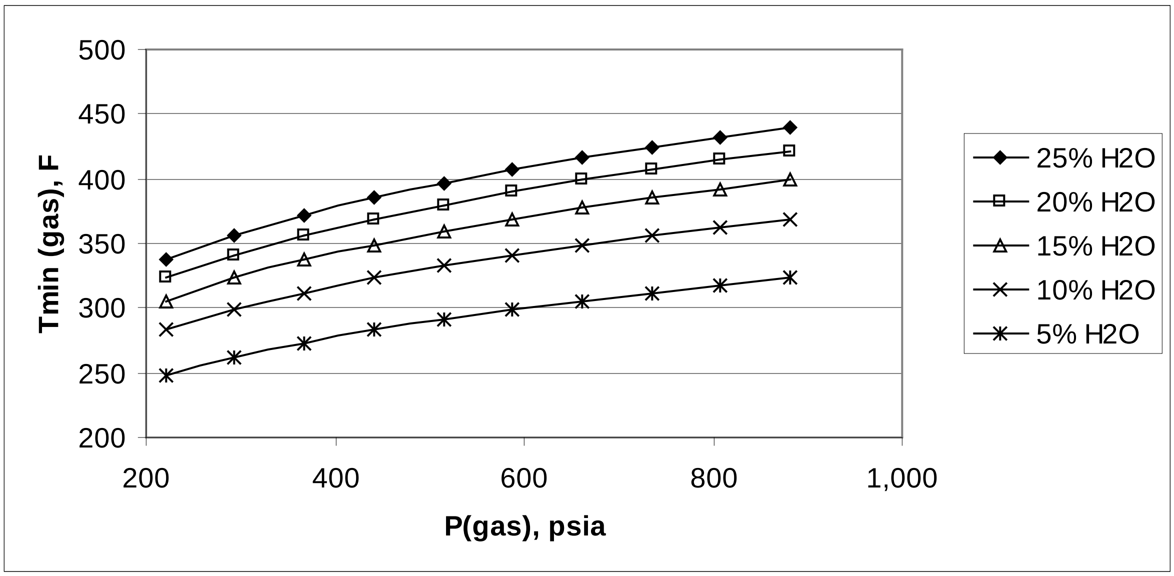


Figure 1 – Minimum Syngas Temperatures at Various Levels of Humidification

Overall Plant Steam Requirements [EnviRes]

What kinds of HP, IP, and LP steam transactions will occur between the gasification island and the HRSG?

The amount of power generated by the steam turbine depends on the steam flows and steam conditions produced in the HRSG. Heat exchangers in the gasification island or elsewhere may be able to produce or superheat steam for the steam turbine, while some of the steam produced in the HRSG may be needed in other parts of the plant. What are the characteristics of the steam and feedwater flows going to and from the HRSG?

Harmful Contaminants [SWPC-STC]

Which contaminants in the syngas would be harmful to which burner catalysts?

Table 1
Catalyst Contaminants
(by Siemens Westinghouse - STC)

Catalyst Type	Harmful Substances

Power System Startup and Shutdown [EnviRes and SWPC-Orlando]

What are the plant control strategies and valving arrangements for startup, turndown, normal shutdown, and abnormal shutdown?

Dynamic modeling of the power plant is beyond the scope of this contract. Still, agreement is needed on the following general statements.

1. Of the major plant subsystems, the gas turbine probably has the shortest response time, followed by the steam turbine (if there is one), heat recovery steam generator, and gasifier.
2. Gas turbines are normally controlled by control valves that modulate fuel gas flow to the GT burners. Because of these modulations, the syngas flow rate leaving the gasifier may be different than the syngas flow rate entering the gas turbine for short durations while the plant reaches equilibrium. The gasifier and syngas piping should be able to accommodate the resulting pressure rise for a short time, while the gasifier changes load to match the gas turbine.
3. Sudden loss of electrical load will result in the abrupt cutoff of syngas flow to the gas turbine. The control system for the gasification island will need to accommodate this sudden stoppage of the demand for syngas flow.
4. Although the plant will probably be designed with flares for emergency gas venting, many jurisdictions will not allow gas flaring as part of normal operation. The syngas valving system will have to accommodate local flaring restrictions for all non-emergency changes in load.

REPLY FROM DONALD P. MALONE TO DENNIS HORAZAK

Dennis,

I have reviewed the subject document. The following items constitute a partial response with the best information we have available:

1. Syngas Composition, The syngas from petroleum coke will be virtually identical to that from coal. The hydrogen rich gas (not used for fuel) is richer in hydrogen for the petroleum coke case because there is little Oxygen in petroleum coke compared to coal. Most oxygen in the feed results in CO in the hydrogen rich stream. The composition shown in the document appears to be accurate. The contaminants listed in Table 3 should be less than 1 ppmv.

2. Emission Standards, Presently we don't have the standards for the proposed site. We will determine them later in the project. For now, the values of 2 ppmv for both CO and NOx seem to be the best choice.

3. Gas Turbine Sizes, Fuel produced in the demonstration may be less than that required by a 1x1 W501D5A. We may consider increasing the plant size, blending syngas with natural gas or using a smaller combustion turbine if possible.

4. Use of Natural Gas, As indicated above, we plan to have natural gas available. It will probably be used for startup, shutdown if necessary, and perhaps continuously for blending. I believe that there is a typo in the second sentence of the second paragraph of this section where it says, "Also, natural gas can be blended with natural gas to....". It should read, "Also, natural gas can be blended with syngas to....".

5. Syngas Supply Pressure, Our current intention is to produce the syngas at a pressure of 350 to 400 psig.

6. Syngas Supply Temperature, The dew point of the syngas should be 110°F or lower so the supply temperature should be 160°F or lower.

7. Overall Plant Steam Requirements, We have not finalized our steam requirements. We may drive the Air Separation Plant (ASP) with steam or electricity. These requirements will be developed during the project. As they are determined we will make them available.

8. Harmful Contaminants, We are not aware of any significantly harmful contaminants. Mercury should be less than 50 ppbv, some H_2S and COS may be present, but their concentration should be in the 10 to 100 ppmv range.

9. Power System Startup and Shutdown, We believe that the HyMelt process should offer a good dynamic response capability. We should be able to drop to 50% of capacity in less than 5 minutes. This should greatly reduce the need to flare fuel. As better information is developed we will make it available.

Best regards,
Don

-----Original Message-----

From: Horazak Dennis [mailto:dennis.horazak@siemens.com]

Sent: Tuesday, July 29, 2003 4:53 PM

To: 'dpmalone@alltel.net'

Cc: Hannemann Frank CTET

Subject: Gas Turbine Functional Issues

Don,

I have attached a list of technical issues that I believe EnviRes and SWPC need to resolve. None of them are major issues, but they need to be addressed so we can begin to work on our portion of the project. The issues are generally detail-oriented. The attached file describes the information that SWPC needs in order to define the functional specification of the gas turbine operating with HyMelt off-gas.

<<GT Issues.doc>>

Please review this list at your earliest convenience, then call me so we can discuss how to attack the list. Thanks for your help.

Regards,

Dennis

Dennis A. Horazak
Siemens Westinghouse Power Corporation
4400 Alafaya Trail - MC Q1-101
Orlando, FL 32826-2399
Tel: 407.736.5131
Fax: 407.736.5014

APPENDIX III

Comparission between diffusion and catalytic burners

Table A1
Candidate Burner Comparison

	DF-42	Catalytic
Technical Areas		
Commercial fleet	(+) Many running units	(-) None running
Proven on CO/H_2 fuel?	(-) No	(-) No
NOx control	(-) Burner designed for 42 ppm with diesel fuel (DF). May get 25 ppm with syngas. Needs steam or water injection, plus SCR	(+) Lowest NOx emission. Catalytic burner has tested capability to achieve around 2 ppm NOx without SCR (but not with this fuel). SCR may not be needed.
Dual-fuel capability (natural gas and high-CO syngas)	(+) Dual-fuel capable	(-) Dual-fuel capability may be complicated.
Programmatic Areas		
Technology advancement	(-) Mainly adaptation of an existing design	(+) Development of new type of burner
Scalability	(-) ~1/250 scale testing	(+) ~full-scale testing
Burner geometry model	(-) Model needed	(+)STC has model
Transition geometry model	(-) Model needed	(-)Model needed
Kinetics model	All by CS&E	Catalytic partial reactions by STC, downstream combustion by CS&E
Test burner design	(-) Design needed	(+) Design complete
Test burner fabrication	(-) Hardware needed	(?) Hardware may be needed
Commercial Areas		
GT (w/burner) capital cost	(+) Slightly less?	(-) Slightly more?
SCR capital cost	(-) SCR needed	(?) SCR may not be needed
SCR operating cost	(-) SCR needed	(+) less than for DF-42, maybe zero.
Development needed	(+) Basic burner is developed, may need modification	(-) Burner development needed
Commercial Availability	(+) Sooner	(-) Later