

**DEVELOPMENT OF A HYDROGASIFICATION PROCESS FOR CO-
PRODUCTION OF SUBSTITUTE NATURAL GAS (SNG) AND ELECTRIC
POWER FROM WESTERN COALS – PHASE I**

Topical Report

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ABSTRACT

The Advanced Hydrogasification Process (AHP) – conversion of coal to methane – is being developed through NETL with a DOE Grant and has successfully completed its first phase of development. The results so far are encouraging and have led to commitment by DOE/NETL to begin a second phase - bench scale reactor vessel testing, expanded engineering analysis and economic perspective review.

During the next decade new means of generating electricity, and other forms of energy, will be introduced. The members of the AHP Team envision a need for expanded sources of natural gas or substitutes for natural gas, to fuel power generating plants. The initial work the team has completed on a process to use hydrogen to convert coal to methane (pipeline ready gas) shows promising potential. The Team has intentionally slanted its efforts toward the needs of US electric utilities, particularly on fuels that can be used near urban centers where the greatest need for new electric generation is found.

The process, as it has evolved, would produce methane from coal by adding hydrogen. The process appears to be efficient using western coals for conversion to a highly sought after fuel with significantly reduced CO₂ emissions. Utilities have a natural interest in the preservation of their industry, which will require a dramatic reduction in stack emissions and an increase in sustainable technologies. Utilities tend to rank long-term stable supplies of fuel higher than most industries and are willing to trade some ratio of cost for stability. The need for sustainability, stability and environmentally compatible production are key drivers in the formation and progression of the AHP development. In Phase II, the team will add a focus on water conservation to determine how the basic gasification process can be best integrated with all the plant components to minimize water consumption during SNG production.

The process allows for several CO₂ reduction options including consumption of the CO₂ in the original process as converted to methane. The process could under another option avoid emissions following the conversion to SNG through an adjunct algae conversion process. The algae would then be converted to fuels or other products. An additional application of the algae process at the end use natural gas fired plant could further reduce emissions.

The APS team fully recognizes the competition facing the process from natural gas and imported liquid natural gas. While we expect those resources to set the price for methane in the near-term, the team's work to date indicates that the AHP process can be commercially competitive, with the added benefit of assuring long-term energy supplies from North American resources. Conversion of coal to a more readily transportable fuel that can be employed near load centers with an overall reduction of greenhouse gases is edging closer to reality.

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**THERE IS A TIDE IN THE AFFAIRS OF MEN,
 WHICH, TAKEN AT THE FLOOD, LEADS ON TO FORTUNE:
 OMITTED, ALL THE VOYAGE OF THEIR LIFE
 IS BOUND IN THE SHALLOWS OF MISERIES ...
 AND WE MUST TAKE THE CURRENT WHEN IT SERVES,
 OR LOSE OUR VENTURES.**

WILLIAM SHAKESPEARE

LIST OF ACRONYMS

AHP	Advanced Hydrogasification Process
AP	Air Products and Chemicals, Inc.
APS	Arizona Public Service
ASTM	ASTM International (formerly American Society of Testing & Materials)
BHP	BHP Navajo Coal Company
BSR	Bench Scale Test Reactor
BTU	British Thermal Unit
Cabot	Cabot Corporation
COR	Contracting Officer Technical Representative
DeS	Desulfurization Unit
DeC	Decarbonization Unit
DOE	Department of Energy, USA
ETEC	Electric Transportation Engineering Corporation
EV	Earned Value
°F	Degrees Fahrenheit
FFTF	Flex-Fuel Test Facility
GTI	Gas Technology Institute
GW	Gig watt
HG	Hydrogasification Reactor
IGCC	Integrated Gasification Combined Cycle
lb/hr	Pounds per hour
MeT	Methanation Unit
MM	Million
MMBTU	Million British Thermal Units
MMBTU/hr	Million British Thermal Units per hour
MMSCFD	Mill in Standard Cubic Feet Per Day

The AHP Project**Topical Report****NETL/DOE**

MW	Megawatts
NETL	National Energy Technology Laboratory
O&M	Operations and Maintenance
PSIA	Pounds per square inch absolute
PSIG	Pounds per Square inch gauge
POX	Partial Oxidation
R&D	Research and Development
SDG&E	San Diego Gas and Electric
SNG	Substitute Natural Gas
SRP	Salt River Project
STPD	Short tons per day
WBS	Work Breakdown Structure
WGA	Western Governors Association
ZECA	Zero Emissions Coal Alliance

I. Executive Summary

1. Project Review

The AHP Team has demonstrated in the first phase that the development of a commercially viable advanced gasification process that produces pipeline quality substitute natural gas (SNG) with near zero emissions at a competitive cost is feasible. The process uses hydrogasification as its basis, which offers higher operating efficiencies, less water consumption, and greater viability with low rank western coals (LRC) compared to typical partial oxidation (POX) gasification SNG processes. The hydrogasification process is designed to accept hydrogen produced from renewable or non-greenhouse gas emitting sources.

SNG could fuel a sizable portion of the 60 GW of new electric generation anticipated in the western United States over the next two decades, and supplement the diminishing production of domestic natural gas. SNG would become a new supply source for existing natural gas infrastructure, and protect the fuel supply for existing natural gas fired electric generation.

The Advanced Hydrogasification Process created in Phase I could be commercially achievable within the next six to eight years. For purposes of the initial demonstration, coal and ash properties from the New Mexico Navajo Mine South Sections (1 billion ton reserve) were used in testing. Mass and energy balances for the process were modeled using Aspen Plus. Additional western coals were analyzed from the Arizona Kayenta Mine, New Mexico Lee Ranch Mine, and from Wyoming's Antelope Valley Mine. Thermodynamic studies concluded that hydrogasification is economical and fuel efficient with low water consumption. Hydrogen can be provided from several sources (including renewable) or in combination. When hydrogen is provided from coal, SNG can be produced below the projected market price of natural gas and, therefore, the use of SNG in existing and future power plants has strong commercial appeal. When hydrogen is provided by renewable wind energy, SNG meets the long-term objectives of efficiency and sustainability. When hydrogen is provided by the grid, then SNG meets the objectives of load shifting and energy storage.

CO₂ created in the process is converted to methane or renewably recycled back into biofuel, increasing process efficiency while eliminating waste. The Hydrogasification process created in Phase I meets three advanced coal objectives - high efficiency, low water consumption, and no CO₂ emissions. Hydrogasification as an independent producer of pipeline ready methane, or in conjunction with existing or envisioned electric generation facilities, opens the way for a stable, sustainable, and clean US based source of fuel for many decades.

**“THERE IS NO SUCH THING AS A FAVORABLE WIND FOR ONE WHO HAS NO IDEA WHERE HE IS GOING.”
SENECA**

2. Statement of the Significance of the Problem

North American natural gas supplies are limited and natural gas costs are rising. Currently US production does not meet domestic demand. Imports from Canada fill the increasing gap. Supply bottlenecks and high gas costs pose a serious challenge to the electric power industry, which over the last two decades has become a major consumer for gas turbine and combined cycled power plants. These natural gas fueled power plant technologies provide clean and efficient power generation, which can be located near load centers, reducing transmission costs and reliability risks associated with long high-voltage transmission lines. In the next two decades, electric utilities serving the western United States must install 60GW of new electric power generation to meet new loads, making selection of technology for the next generation of electric power plants of critical importance. Continued use of existing natural gas fueled power plants and the addition of new combined cycle plants extend the efficiency and environmental compatibility, which the electric utility industry has enjoyed over the past two decades. However, future natural gas price increases and potential natural gas shortages create significant risk of high cost and low reliability for natural gas fueled power plants. The alternatives available to electric utilities are, few. Conservation can, and has, made a significant contribution to load reduction and eased the need for new generating plants. However, load in the Western United States continues to grow, driven by population growth and economic expansion. Renewable resources, such as biomass, geothermal and solar, make marginal contributions to new generation. Wind resources are large and are being developed but are only marginally dispatchable. Coal and nuclear offer the only real alternatives for bulk electric power generation. Coal, fueling traditional pulverized coal power plants, offers a reliable and cost-effective source of power but has significant greenhouse gas challenges. A nuclear station has not been ordered since the early 70's. While this may change with a renewed interest and Federal support, significant impact is at least two decades away.

Most of the developed coal gasification technologies are designed to produce synthesis gas (syngas), which primarily consists of carbon monoxide and hydrogen, and contains only a small fraction of methane. These gasification processes are specifically developed for IGCC or petrochemical applications. Hence, IGCC gasifiers cannot fuel existing combined-cycle power plants and must be co-located with new generating plants on the same site, reducing siting flexibility, requiring specifically designed and fabricated turbines, and necessitating long high-voltage transmission lines to reach load centers. Based on these limitations a more flexible and competitive gasification process is needed to move this technology forward.

Faced with this dilemma, electric utilities are actively seeking advanced technology alternatives for their next generation of electric power plants. APS (and other members of the Team), has been investigating the production of substitute natural gas (SNG) produced from coal, as a technology to: (1) protect both existing and future power plants against fuel shortages and price shocks; (2) allow the continued use of high efficiency combined cycle power plants; (3) facilitate locating power plants near load centers to minimize transmission lines and improve system reliability; (4) minimize both fresh water use and wastewater production, (5) provide the opportunity to economically introduce renewable power-generation fuel; (6) leverage algae recycle to capture CO₂. Decrease overall operating cost through the sale of algae fuel and other products; and (7) develop a stable sustainable low emission CO₂ fuel. Given the vast coal resources in the United States, efficient production of SNG from coal offers supply and price stability. In addition coal transportation infrastructure to electric power generation facilities already exists.

3. Process Flow

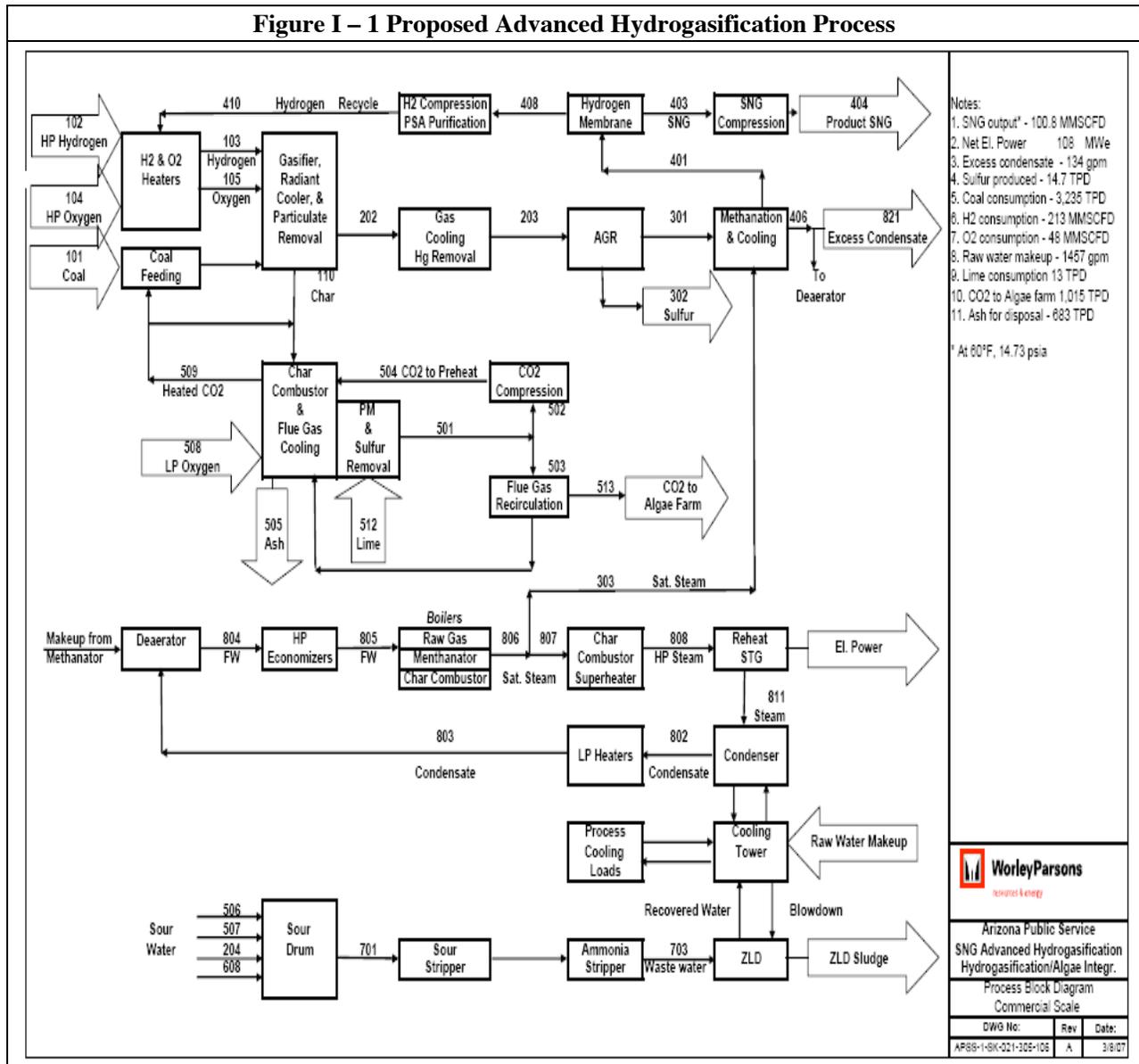
The Team based its initial and current design on significant previous work on gasification and gasification using hydrogen done in the US, Japan and Europe over the past 30 years. Most of the previous work ended in the early 1980's (ARCH concluded in the early 90's). The most current relevant R&D has been the ZECA project, which several Team members participated. Analysis, modeling and experimentation by the Team built on this prior work.

Phase one of work has resulted in a design that incorporates past experience and new concepts. The work and conclusions during this phase have been verified and modified by our newest team member who had an integral role in the Japanese ARCH (Advanced Rapid Coal Hydrogasification) process (the original research program effort was sponsored by Osaka Gas and British Gas). Phase one integrated initial design concepts, testing, advanced modeling and analysis to develop an energy efficient design based extensively on commercially proven processes. The first phase work concentrated on removing as many uncertainties as possible from the design. While the gasification reactor needs considerable refinement, most of the other components could be ordered from existing supply sources today. Therefore, the work in phase two will concentrate on refining the reactor.

The process has evolved from a hot gas recycle loop with calcium carbonate regeneration to one of refined simplicity. Further advances are anticipated in both processes and materials. The coal to SNG process as envisioned is workable and efficient, a major step from early 2006 when the DOE approved the start.

4. Proposed Technology

The Team has developed a process, which integrates a hydrogasification reactor with co-production to efficiently produce SNG and utilization of the CO₂ within the process. Co-production CO₂ will be captured and re-used as a carbon based fuel.



In the Advanced Hydrogasification Process (Figure I-1), coal is gasified in the presence of hydrogen to a methane rich fuel gas stream. Hydrogen enters the hydrogasifier reactor (HG) and mixes with coal, converting a high percentage of the carbon in the coal to methane. The conditions required to maximize

this conversion will be further developed in phase two. The product stream is transformed in a commercial methanation unit (MeT) into a SNG stream meeting pipeline requirements.

The Advanced Hydrogasification Process has a number of areas to be tested and refined, but preliminary engineering modeling indicates the anticipated efficiencies will be achievable for large-scale application. The team is particularly encouraged by the design that has evolved, as most of the downstream equipment in this process is currently commercially available, significantly reducing risk going forward. The proposed phase two will test the concept and consider means to maximize efficiencies.

5. Technical Challenges

The overall integration of a hydrogasification reactor is novel and will require testing to characterize the reactions and refine the process design. A fully integrated test plan for Phase II and parallel engineering effort has been developed including schedule, budget and work scope. Each member of the Team has critical roles in this development and is committed to move forward.

- Hydrogasifier: The Advanced Hydrogasification Process design concept will require tests with western coal to determine extent of carbon conversion. Parameters such as temperature, pressure, H_2/C ratio, and residence time will be tested to determine design factors needed to specify the engineering and commercial-scale units.
- Oxygen Hydrogen Tip Burner: Will require design and material investigation in phase two.
- Coal Feed System: Coal feeder technology for the hydrogasifier will require investigation. Technologies for the coal feed system and their impacts on the hydrogasifier will be investigated and a technology selected in the proposed program of work.
- Hydrogen Source: Investigation and analysis of whether hydrogen is purchased or produced on site and what will be the alternative methods that meet production and economic requirements.
- Algae Recycle: This process is an efficient means to gather and re-use carbon from CO_2 , but field application and testing remains to be completed and verified. The next level algae recycle testing will also be done at a coal fired power plant during Phase II.
- Other Components: The other system components are commercial technologies and are expected to be used with only minor modifications tailored to the specific coal and site conditions.

The technological risks have been reduced but are still significant. While the process is fairly well understood a number of options remain.

6. Technical Merits

Based on the hydrogasification pilot tests, extensive analysis and engineering assessments, the Advanced Hydrogasification Process is expected to have the following technical advantages:

- The ability to gasify western coal without severe energy penalties associated with other gasification technologies.
- The hydrogasification reactor operates at a lower temperature than other coal gasification processes. This is expected to alleviate slag-handling problems, particularly with sub-bituminous and lignite coals.
- The hydrogasification reactor produces a higher fraction of methane than partial oxidation reactors, thereby reducing the "lift" required by methanation.
- CO₂ may be combined with hydrogen to create methane, eliminating the need for expensive, commercially available "back end" clean up processes.
- Carbon capture through a renewable process using an algae recycle offers an alternative means of CO₂ capture and re-use, and could be used at combined cycle plants to further preserve and re-use carbon reducing the green house gas impact for the entire end to end production of electricity.
- Carbon capture and re-use (algae recycle) contributes to energy sustainability and adds an additional source of revenue to offset gas conversion costs.
- The process allows the introduction of renewable hydrogen into the process, providing a renewable energy addition to electric utility generation portfolios, reducing CO₂ production and providing a significant market to stimulate the development of renewable hydrogen.
- Assessments show that the process will be more efficient than alternatives, due to lower reaction temperatures and higher methane production in the initial reaction.
- Water consumption for the process will be lower than with other gasification technologies because of reduced water requirements for slag handling.
- While there are clearly several areas of risk and uncertainty that require tests and development, the Advanced Hydrogasification Process uses a large portion of commercially available components, which are expected to speed its commercial application.

**AHP HAS THE POTENTIAL TO BE A WIDELY USED CLEAN, ECONOMIC SOURCE OF ENERGY FOR THE US
FOR A LONG TIME INTO THE FUTURE.**

“TO LEARN SOMETHING AND THEN PUT IT INTO PRACTICE AT THE RIGHT TIME: IS THIS NOT JOY.” THE ANALECTS OF CONFUCIUS

II. Introduction And Background

1. The Start

The APS Team has benefited from a long history of interest in carbon conversion and the application of hydrogen in that process. The APS Team has made significant efforts to learn from the past both as a guide to go forward and as a warning of paths to avoid. APS team members evolved through several iterations toward the concept that was proposed to the DOE, and had done considerable work prior to the proposal. Following the acceptance of the proposal the process continued to evolve and make a number of significant transitions. There were a great many contributors to the growth and progress of the AHP including Dr. Klaus Lackner who provided the first unified process, John Ruby and the Nexant team who performed the original research and comparisons that sparked interest in going forward, Dr. Francis Lau who with GTI confirmed the potential and viability of a hydrogasification process, Dr. Xiaolei Sun who along with Dr. Weimer, NETL, WorleyParsons and several other key members of the team helped the process evolve into its current state. Critical contributions by several members of NETL and Noguchi who helped guide reactor design along side the practical guidance and input from John Boyle and Don Karner. As indicated above the Team is deeply in the debt of those who have gone before us building many of the bridges we have crossed. And finally the project exists thanks to the considerable effort and belief of APS and Ray Hobbs that an answer may lay down this particular path.

Background and Existing Technologies/Methodologies: Work was performed during the 1970s and 1980s to develop SNG from coal resources. Three significant efforts during this era were undertaken. The Dakota Gasification Company's Great Plains Synfuels Plant represents the greatest advance in commercialization during this period. This plant employs Lurgi fixed-bed gasifiers for SNG production. The plant relies on conventional gas cooling and a low-temperature, acid gas removal process for selective removal of H₂S and CO₂. These processes inherently limit the plant's overall process efficiency.

It is unlikely that this technology would be used in today's environment. HYGAS technology[1], a hydrogasification precursor, was very successfully pilot tested in the 1970s at the Institute of Gas Technology (now GTI) using a 72-ton/day facility[2]. Significant engineering was completed for commercial designs[2], but when forecasts of energy prices dropped, the technology development was discontinued. Finally, a 40-pound/hour facility, sponsored by the U.S. Environmental Protection Agency, was built at the University of California Riverside in 1998[3]. This plant was designed to convert biomass to methanol for use as a clean transportation fuel and did not make a contribution to hydrogasification technology.

In addition to these previous experiments with hydrogasification technology, the Japanese government has pursued coal hydrogasification for SNG production. The ARCH[4] project showed that hydrogasification of coal maximizes direct SNG production in the initial coal conversion step. The Netherlands Energy Research Foundation ECN, has published extensively on advanced hydrogasification of biomass for SNG production,[5]; suggesting that when hydrogasification is utilized with hydrogen from external renewable resources, the conversion of biomass to methane-rich gas becomes feasible.

APS, along with 17 other utilities and power generation stakeholders, joined the Zero Emission Coal Alliance (ZECA). ZECA commissioned extensive studies[6] on the use of hydrogasification to produce a hydrogen stream to be used in a solid-oxide fuel cell for power generation. It was concluded from these studies that the process investigated by ZECA could not be implemented in a time frame consistent with the next generation of power plants and that some of the technologies (solid-oxide fuel cell and CO₂ sequestration) embodied in the ZECA process were not currently practical. APS, however, was cognizant of the fact that process investigations showed promise for the hydrogasification portion of the process to produce methane efficiently and at lower temperature and pressure than more traditional partial oxidation (POX) processes.

APS commissioned Nexant, LLC (Nexant) (which had been involved with hydrogasification since the 1970s[7] and a significant contributor to the ZECA process analyses) to study both hydrogasification

and POX processes for the production of low BTU fuel gas and SNG (suitable for introduction into existing natural gas pipelines). The investigation included conceptual design and preliminary economic studies comparing the hydrogasification process with a conventional POX gasification process equipped with low-temperature syngas cooling and acid gas removal processing. The study investigated a 1000 short ton/day commercial-scale facility, fully integrated into an existing APS power facility for maximum usage of all existing infrastructure; e.g., allowing the export of steam produced from the proposed process (syngas cooling and methanation units) to the existing APS facility for power co-production. The studies incorporated sub-bituminous coals from APS's San Juan Basin field as the feedstock. The following scenarios were evaluated, with the results shown in Table II - 1.

- POX to produce synthesis gas (syngas) for combustion in existing coal-fired boilers. The syngas requires only minimal cleaning under the design criteria that sulfur and other pollutants will be controlled with existing equipment.
- Hydrogasification to produce syngas for the existing coal-fired boiler.
- POX to produce SNG using methanation. The SNG could be used at the power plant or sold to natural gas markets.
- Hydrogasification to produce SNG for power generation or sale.

Table II - 1; Summary of Nexant Gasification Study

Parameters	Syngas Production		SNG Production	
	Case 1, POX	Case 2, Hydrogasification	Case 3, POX	Case 4, Hydrogasification
Coal Feed, STPD	1,000	1,000	1,000	1,000
Coal Feed, MMBTU/hr	850	850	850	850
Power Consumption, kW	12,040	12,370	16,910	16,850
750 psig/550 °F Steam Production, MLbs/hr	0	0	63	30
150 psig/400 °F Steam Production, MLbs/hr	0	0	67	79
60 psig/310 °F Steam Production, MLbs/hr	0	76	-27	59
Water Use, 10 ³ LB/hr	133.6	98.5	148.0	72.5
Product, MMSCFD	58.6	42.8	11.8	13.9
Product, MMBTU/hr	593.4	644.4	460.6	550.0
Efficiency	65.0%	72.4%	50.7%	62.2%
Performance Delta		7.4%		11.5%

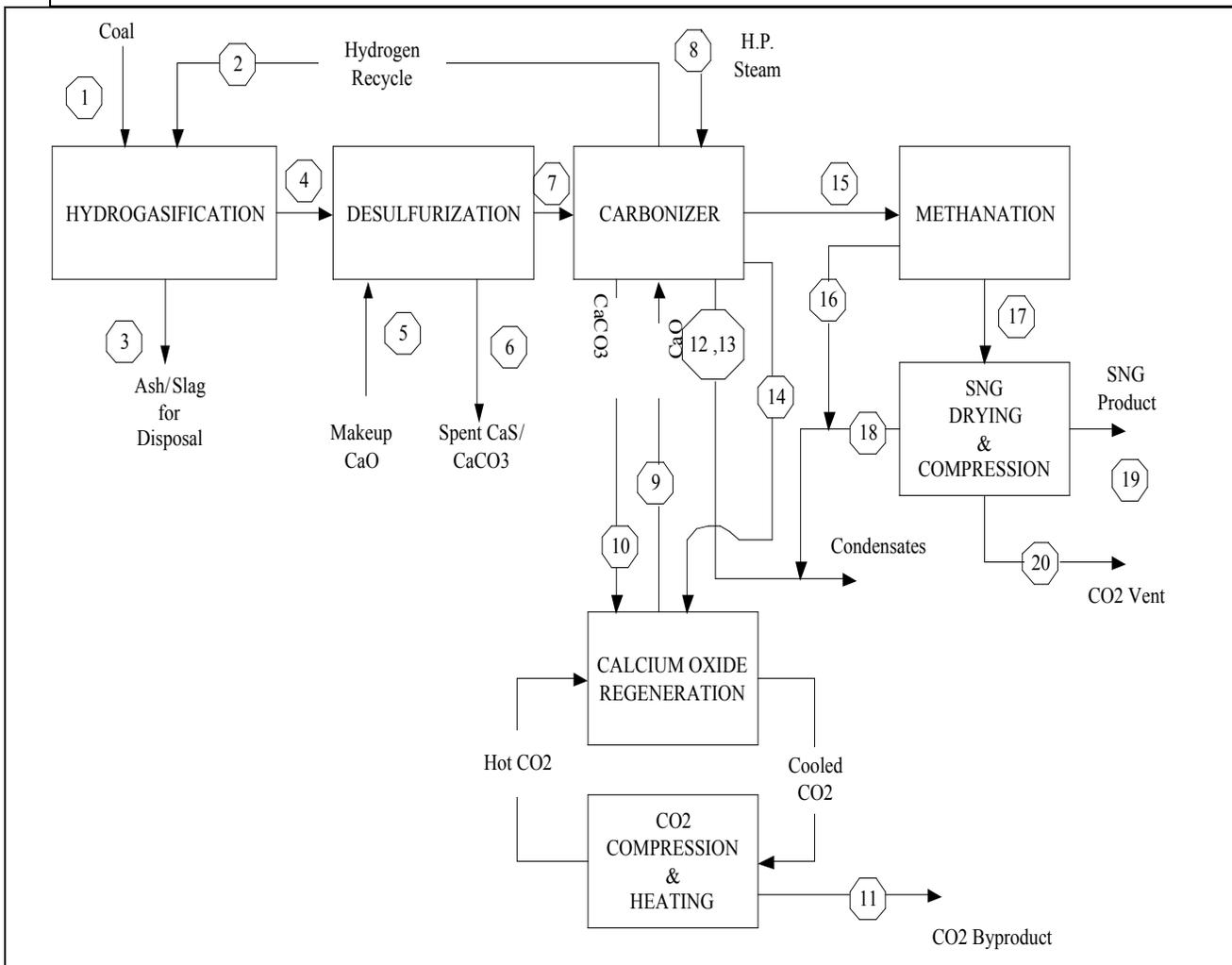
- Notes: (1) Syngas produced from hydrogasification has a higher heating value. It consists mainly of H₂ and CH₄. In comparison, fuel gas produced from POX contains mainly CO, H₂ and CO₂
- (2) Efficiency for Case 4 becomes 59% if CO₂ product is compressed to 2,000 psig
- (3) STPD = short tons per day
- (4) MMBTU/hr = millions of BTUs per hour
- (5) 10³ lb/hr = thousands of pounds per hour
- (6) MMSCFD = millions of standard cubic feet per day

The hydrogasification process was shown to produce significantly more fuel gas and SNG product than the POX process from the same amount of San Juan Basin sub-bituminous coal. The fuel gas produced from hydrogasification enjoys a higher heating value and consists predominately of H₂ and CH₄. In comparison, the fuel gas produced from POX contains mainly CO, H₂ and CO₂. The auxiliary power requirements are about the same for the POX and hydrogasification designs. As shown, hydrogasification offers a significant advantage in efficiency for SNG production. Very important to western utilities is process water use. Water consumption for the hydrogasification process was evaluated to be approximately one half that of POX process, due largely to grey water created by POX bottom ash handling systems when used with high moisture/ash western coals.

The process model for the 1,000 short ton/day process analyzed by Nexant is shown in Figure II-1. The process uses low-rank western coal (typical of that burned by APS) and operates at approximately 1500°F and 850 psig. Carbon in the coal feed reacts exothermically with hydrogen in the

hydrogasification reactor. The methane rich syngas leaving the hydrogasification reactor is routed through a high temperature desulfurization unit containing a packed bed of CaO based sorbent to react and remove the sulfur components prior to sending it onto the downstream carbonizer unit. Within this carbonizer unit, CO in the syngas is shifted with steam in the presence of CaO to produce a hydrogen rich stream with a proper H₂:CO ratio that can be sent onto the downstream methanation reactor for SNG production. A portion of the syngas stream is recycled back to the hydrogasification reactor (stream 2 in Figure II-1). The amount of gas recycling is governed by the need to maintain a critical hydrogen partial pressure in the hydrogasification reactor as well as to provide enough heat to allow a sustainable reactor operation condition at 1500°F.

Figure II-1; Hydrogasification Based SNG Production



The reforming water-gas-shift reactions within the carbonizer are promoted by capturing the CO₂ byproduct with CaO to form CaCO₃. The production of CaCO₃ is an exothermic reaction. Heat is recycled with the hydrogen stream back to the hydrogasification reactor. CO₂ captured by the CaCO₃ can be regenerated via heating. A small portion of the unconverted syngas is used as fuel in a furnace to provide the needed heat for this purpose. The recovered CO₂ is then dehydrated and compressed to 2000 psig, ready for pipeline transport and sequestration.

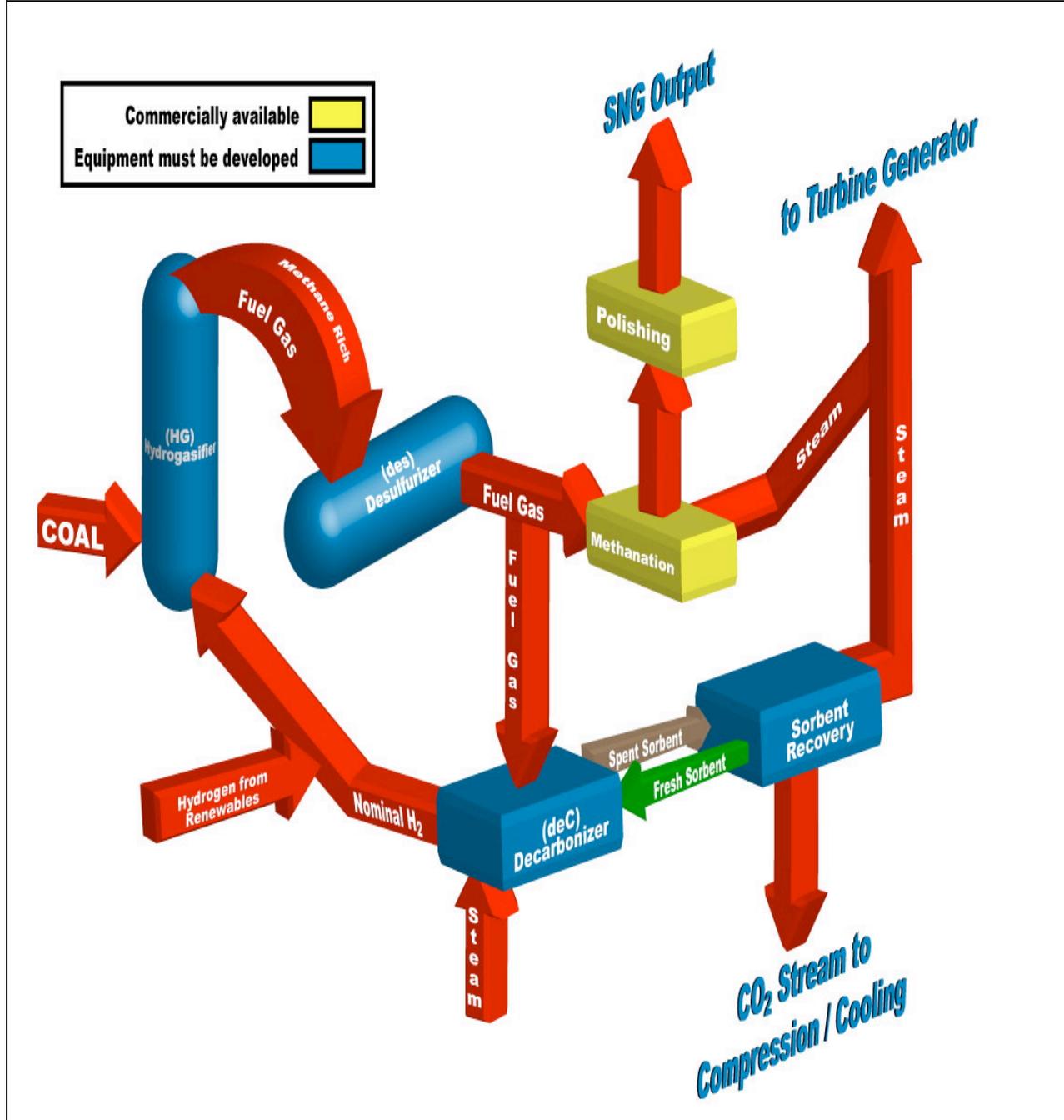
The process shown in Figure II-2 is for a single-train, commercial-scale facility as initially envisioned for the SNG project in 2005. The process assumed gasification of 1,000 TPD of coal and assumed a production close to 14 MMSCFD (160 MW equivalent) of SNG. The process might have had the potential to capture all (100%) of the CO₂ produced from coal if a slipstream from the process is not required to provide fuel for CaO regeneration. The process produced steam at three pressure levels, ready to be exported to an existing power plant onsite or to a dedicated turbine for power co-production (Figure II-2). It would have required approximately 17 MW of power, mainly for recycled gas compression use, which was assumed to be readily available on a site with an existing power station. The process could have been designed to co-produce all the power required for in-plant use, at a small sacrifice in overall process efficiency.

Based on the early studies and comparisons sponsored by APS, it formed a team to further develop the concept of integrating the hydrogasification reactor and the limestone carbonation – decarbonation cycle. This process specifically designed to produce pipeline-quality SNG, using western coal from the San Juan Basin in Northwestern New Mexico, with high efficiency and low water consumption. This novel process design was the focus of the project at its inception. Although the early “Loop” process appeared to be both elegant and achievable critical examination in early Phase I resulted in a decision to remove some of the complexity and uncertainty in the original design.

2. Proposed Technology/Methodology

The originally proposed process (Advanced Hydrogasification Process), integrated a hydrogasification reactor and a de-carbonizer (since dropped) to efficiently produce SNG and co-produce electricity with CO₂ capture. Hydrogen produced from wind energy and other processes was originally incorporated into the process, which would increase the methane to carbon ratio and decrease the amount of CO₂ to be captured. The original APS Advanced Hydrogasification Process is shown schematically in Figure I-2.

Figure II-2; Proposed APS Advanced Hydrogasification Process



Process Description: In the Advanced Hydrogasification Process, coal was to be gasified in the presence of hydrogen to a methane rich fuel gas stream. Hydrogen entered the hydrogasifier reactor (HG) and mixed with coal, converting a high percentage of the carbon in the coal to methane. The fuel gas stream was then subjected to a desulfurization unit (eliminated during the phase one), which was intended to

remove sulfur and other impurities from the stream. After desulfurization, the stream was split into two separate streams. One stream was recycled to the HG, the other stream became the product stream.

The product stream was transformed in a commercial methanation unit (MeT) into a SNG stream meeting pipeline requirements. The carbon content of the hot gas stream was adjusted to assure that the majority of the hydrogen present in the input stream was used to convert CO and CO₂ into methane. The product stream was to be cooled prior to methanation allowing the MeT to operate at lower temperatures commensurate with commercially available equipment. Waste heat from this process was used to produce steam for electricity co-production. Finally there was a polishing step, where the SNG is upgraded, as required, to pipeline conditions.

The recycled stream passed through a decarbonization unit (DeC), which was to use high temperature sorbents to remove carbon dioxide from the stream. Adding steam to this gas mixture, either during or after decarbonizing, was to result in a water gas shift reaction, producing hydrogen for recycling back to the HG. The high temperature sorbent in the DeC unit had to be cycled between absorption and CO₂ recovery. This required a thermal swing for CO₂ release. The energy cost of the CO₂ release was to be at least partially recovered by the high temperature heat release due to the heat of sorption when CO₂ was absorbed. The CO₂ released was then readied for sequestration in pipeline quality liquid form (2200 psia, -40°F dewpoint) by commercial compression/cooling technology. A small fraction of the CO₂ may have been added to the MeT unit in order to adjust the carbon balance. Heat from DeC and Sorbent Recovery unit was recovered in the form of steam to produce electricity via a steam turbine.

Sorbent regeneration was assumed to minimize CO₂ emissions from the process. Alternatively, the sorbent regeneration cycle might have been designed to capture all of its CO₂ from the produced syngas. An energy analysis performed in Phase I to optimize heat integration efficiency for the process led to some of the early concerns and questions.

Technical Challenges: The overall integration of a hydrogasification reactor and a de-carbonizer would have required significant testing to characterize the reactions and refine the process design. Additional aspects of the original process design that were expected to be tested and require engineering development were the Hot Gas Clean-up, Gasifier Hydrogen Recycle, De-Carbonizer, and Coal Feed System. While some of the technical challenges were still present in the Alternative process design several significant ones were avoided.

3. Original Proposal Goals

Relevance to the Announcement Goals/Objectives: The APS/SNG Team hydrogasification co-production process design envisioned a process that would efficiently and economically produce SNG and electric power utilizing existing western coal resources. The APS/SNG process was committed to produce pipeline quality gas with little or no CO₂, depending on the options chosen within the developed design. By introducing renewable hydrogen the AHP can claim partial “renewable” credits.

The project has remained true to the original objectives in spite of technical changes to the process. The original goals and objectives are the continuing focus, as relevant today as when the project began.

Expected Impacts and Benefits - The expected impact/benefit from the development of AHP co-production technology is the introduction of a new and diverse process for gasifying fossil or biomass fuels. As noted below the original benefits remain in place and if anything are more vibrant today than at the start.

Impacts - The hydrogasification co-production concept produces SNG and electricity efficiently without greenhouse gases, allowing commercial SNG production to expand the domestic supply of natural gas. This will stabilize both fuel cost and fuel supply for electric utilities and their customers. Water consumption by the hydrogasification process is significantly less than current gasification processes. This allows electric utilities to meet growing demand in the West for electricity while protecting water resources. Depending on site and other specific conditions, hydrogen to operate the hydrogasifier could be generated from renewable sources, including biomass and wind. With the introduction of algae recycle the process offers flexibility in CO₂ conversion and extends the carbon resources through recycle.

Applicability - The co-production of SNG and electric power can be integrated with existing natural gas transportation infrastructure, without modification. This allows SNG production to occur at a wide range of facilities and locations, limited only by access to a gas pipeline and a source of carbon. Due to the flexibility of the system process the AHP process may be applied to a variety of locales and circumstances.

Risks – Phase one has resolved many issues, while revealing new ones. No fatal flaws have been found that would prevent development of the concept. There are, however, significant design, engineering and manufacturing issues that must be resolved. The most important open issue to be resolved in Phase II is the kinetics within the reactor vessel.

Potential for Breakthrough - The proposed program of work offers potential breakthroughs in (1) integrating hydrogen and coal to create an energy source that will provide a sustainable and stable source of power plant (and other) fuel, (2) development of a fuel from domestic coal with no greenhouse gas contribution and (3) the recycle of carbon through algae to produce additional fuel from the cycle. . The process offers an alternative to producing SNG by burning coal and producing CO₂, which must be captured and sequestered. Instead, adds hydrogen directly to the carbon in coal, without producing CO₂. For an electric utility this offers two significant breakthroughs: (1) the opportunity to produce hydrogen from renewable sources, thereby making the SNG a portion of the utility renewable portfolio, and (2) eliminating the long-term public legal liability associated with CO₂ sequestration.

Summary – The proposed AHP Project has several unique and significant attributes. The proposed program would extend the life and allow for the expansion of combined cycle generating plants through a stable, sustainable and affordable source of pipeline quality SNG. The process as currently envisioned would promote United States energy independence utilizing our abundant coal resources. The AHP Project would successfully demonstrate use of coal with low to zero CO₂ emissions.

4. Work Plan Phase I

The work in Phase one was evolutionary and included several fairly significant modifications. A number of challenges emerged very early in Phase One (it should be noted that several of these challenges were recognized early thanks to perceptive questions directed to the project by members of the NETL Team). First, it became clear that the original work plan was not structured to make sufficient progress in phase one to be ready for Phase Two at the conclusion of Phase One. Second the “loop” in the original design was a technical challenge that would take too long to resolve (this may be a great idea, but a number of technological advancements must be made before it is feasible). And a number of steps that were built into Phase One would not advance existing knowledge merely confirm what were already known. The Project made adjustments to accommodate the changes necessary to overcome these challenges.

Adjustments

Projects tend to evolve as they progress, and R&D projects such as this one change more than most. The Project used the Work Breakdown Structure (refer to Chapter 5) to track and communicate changes, and when required modified member work scope.

The adjustments resulted in a much more “do-able” process design than at the start. Here are a few of the highlights of the changes:

- The initial design was an elegant concept for maximizing hydrogen through recycle. Unfortunately as work proceeded it became clear that with present technology the recycle loop presented too many difficulties. The team began to explore other design concepts ultimately choosing one among several that seemed to offer the best potential for execution in the near term.
- The new design alternatives took considerable effort but resulted in not only a more feasible design but also one with considerably more options that can be explored and used to support the project as it moves forward.
- The team was able to adjust to the demand for additional process design time and resources by reducing TGA coal testing. The team found ways to use a reduced number of tests to reach the initial test objectives and re-direct resources to design. The team added new members with specific design expertise without loss of schedule or increased impact to overall budget.
- The new process design removed the need for sorbents, which for large-scale application are currently unproven adding to project uncertainty. The removal of sorbents increased project probability, reduced operational risk and simplified the process. The team redirected the resources set aside for sorbent TGA testing to cover the increased cost of bench scale reactor test development experiments.
- The “Loop” design had COP2 advantages that the Project was committed to retain. This was accomplished within the new SNG design, although at the expense of added hydrogen &/or use of an algae recycle process which was added to the project. The addition of algae recycle offers additional options and CO2 reduction.

“What doesn’t kill you makes you stronger” is an apt admonition for describing Phase I. Areas of the project that were thought to be firm were questioned and found inadequate. Plans of work that were agreed to by all parties turned out to be of less value than thought. Change was needed and the decision to change, and the actions to carry out the change came quickly. We were able to adjust, find the talent and resources to provide new direction and move the project from one set of work to a very different set of tasks while preserving the overall goals and objectives – and staying within budget and schedule parameters.

“BELIEVE THOSE WHO SEEK THE TRUTH, AND DOUBT THOSE WHO FIND IT.” **ANDRE GIDE**

III. Initial System Investigations

1. Program of Work

Research and development of the Advanced Hydrogasification Process was organized into three phases. In the first phase a given process (described in Section Two) was to be tested and a reactor vessel developed. Unfortunately fairly early in phase one it became clear that the process itself was unworkable, at least based on existing and near-term technology. Rather than abandon the project the team devised a new work plan to focus on the process and attempt to discover alternatives. Two alternatives to the original process (with a variety of options) were quickly developed and tested through analysis and modeling against the original process design.

Considerable effort and creativity was required to develop, and adequately present the alternatives. It was determined that a “competition” between the process alternatives be staged. The more likely of the two alternatives was modeled, with some additional variations, and presented to the team on two occasions. The final presentation (at the third all team meeting, including NETL) was to finalize the decisions with all key team members present. The alternative chosen was further modeled, efficiencies critiqued and the process from end to end analyzed. The selected alternative will be further refined and tested in Phase II.

The change in process was a significant modification to the scope of the project. Fortunately as the alternatives emerged it became clear that sorbent would not play a role in the project, freeing up schedule and resources. Other changes were made to the work scope and resources in order to effectively work on a modified process while maintaining schedule and budget as original contemplated. By maintaining a focus on measurable deliverables, parallel path scheduling and tying the work tasks to firm budget numbers the project was able to sustain the early momentum and successfully resolve the challenges it faced.

Several other modifications and additions in the first phase include algae recycle for CO₂ capture, reactor design changes and contributions from Air Products on the potential for wind developed “renewable” hydrogen. The algae recycle had not been considered in the original scope and is one of several fortuitous additions that enhance the project and open up new possibilities for successful commercial implementation. Reactor design was a part of phase one but the addition of Fuyuki Noguchi to the project was an unexpected bonus that has moved design ideas much further than could have been reasonably expected at this early stage. The various process modeling work by several members of the team

combined to create a sustainable technology with near term development potential. And using wind for hydrogen production was a part of the project's original scope but this area was greatly enhanced by Air Products considerable effort on behalf of the project. Much of the work done on wind as a energy source for hydrogen is new and should enhance the work on others in this area.

2. Work in Phase I

Phase I Modeling, Analysis and Laboratory Testing: Initial analysis, modeling and testing in support of the overall hydrogasification process resulted in a workable process that adheres to all of the original goals and objectives. Some of the coal tests originally planned were found to be redundant and were either replaced with other tests or canceled. The sorbent testing was dropped after the process design was modified. Thanks to the help from NETL and the University of Colorado process modeling was taken further than originally planned. ASPEN modeling by Nexant, WorleyParons and APS was more extensive than originally planned as two alternatives were extensively modeled. The modeling helped develop several key technology solutions. The analysis of the alternatives (and options to the alternatives) was extensive involving all members of the team in greater or lesser roles and the resulting debates pushed the technology in several new and exciting directions.

Phase I Exploratory Engineering: In parallel with the analysis and testing, the Team conducted preliminary engineering to assess the conceptual commercial plant design, and begin the process of defining the Phase III demonstration prototype. Process designs were prepared to define the entire process flow. The engineering effort developed the following major products:

- Design Basis Criteria – The criteria specified site and coal specific conditions, establish design procedures, set cost and economic estimates, and provide other project guidelines.
- Conceptual Process Design – Process diagrams, energy and material balances were prepared, a number of alternative and options were evaluated and compared.
- Mass Balance – Mass Balance studies were completed for several alternatives including with and without algae recycle
- Major Equipment List – Equipment was specified through interaction with equipment suppliers.
- Cost Estimates – Costs for the plant were estimated by obtaining budgetary information from potential equipment and process suppliers.
- Trade-off and Sensitivity Studies – Alternative ways to arrange equipment or processes were examined. Initial equipment specification and availability were determined.

- Techno-Economic Evaluation – The economic analyses includes: capital, maintenance and operating costs; efficiency; fuel limitations and benefits; market/product limitations and benefits; waste stream disposal issues; and water issues.

First Phase engineering was comprehensive and well beyond the originally submitted scope. This is partially due to the additional engineering work needed to support and confirm the variety of changes to the process, the addition of algae recycle to the project and the commitment by WorleyParsons to do what it took to do the job right. The first phase engineering work provides a firm and broad platform on which to build during phase two. Keeping with the original project goal to be a viable technology by the next decade this firm beginning should serve to continue to move the project along at a fast pace. As we have seen from recent inquires of interest from China and Japan, the work completed in the first phase has placed the work to date at the forefront of carbon conversion and CO₂ capture on the world stage.

3. Planned Work

Phase II: Phase II work will be divided into three main areas of effort. The core of phase two will be reactor vessel testing. Included in this work will be the fabrication of the reactor, modeling based on results and various other engineering and analytical functions based on testing.

Second will be work in preparation for moving on to phase three. This work will include selecting a reactor fabricator, selecting a site, determining hydrogen source for the pilot scale and a number of other steps that will prepare the project to move into pilot scale testing of the reactor and the key elements of the process.

Third will be consideration of the economics and commercial viability of the concept. A multiplicity of subjects will be examined focusing on alternatives, cost, and analysis of how AHP might fit into the mix of future energy technology solutions, and under what circumstances. This work will endeavor to project economics and fuel availability for US electric utilities and offer alternatives as to how AHP might fit into the US utility's needs within the next decade.

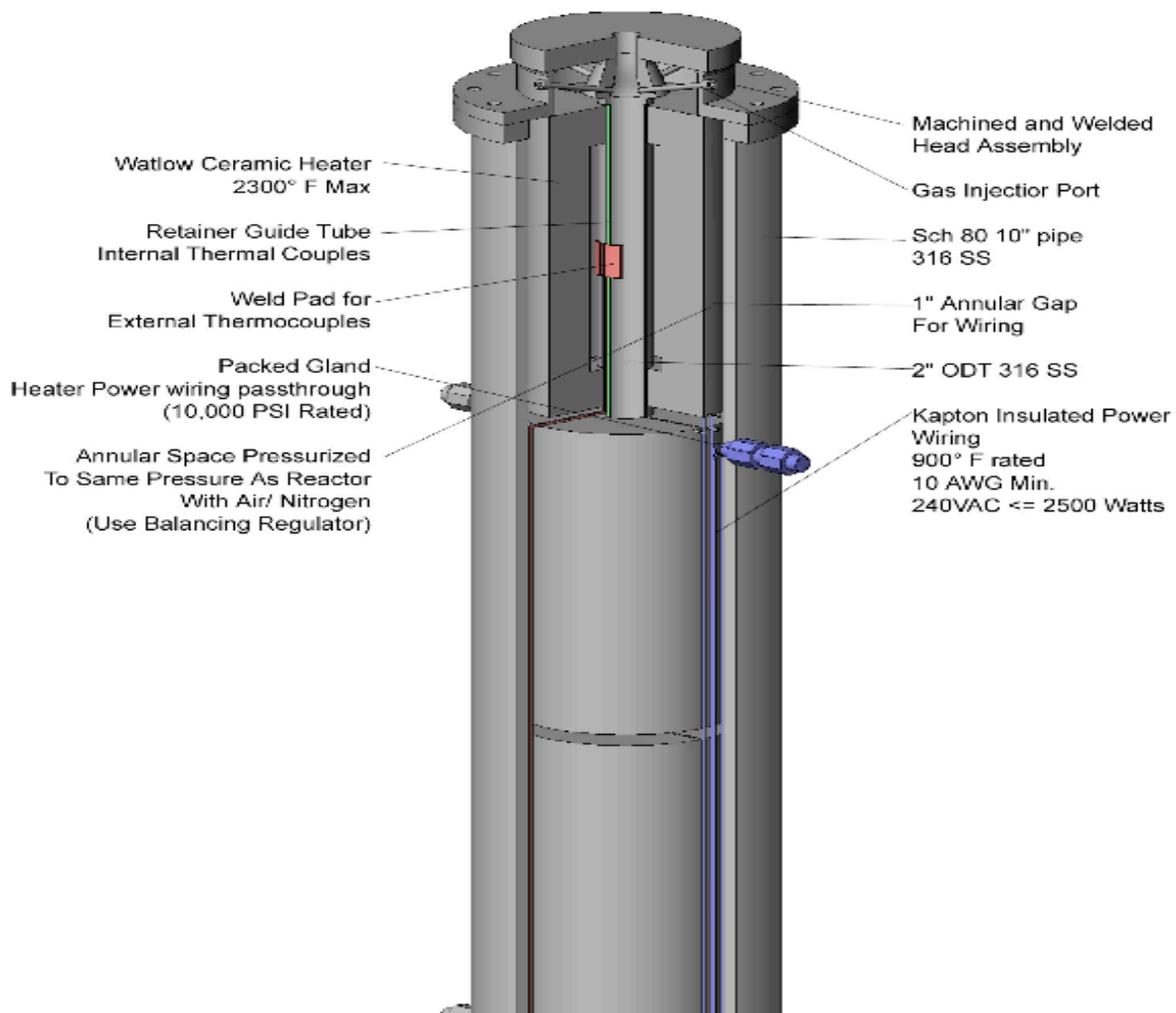
Phase II Bench-Scale Experiments: Based on the results of the modeling and exploratory engineering work in Phase I, a bench-scale testing – a thirty foot reactor vessel test with hydrogen and coal - program will be conducted to complete the hydrogasification process definition and generate data required for design of an engineering-scale system for field testing in Phase III. Major experimental activities in Phase II will include:

- Complete the fabrication of the Test Reactor begun in Phase I;

- Bench-scale testing of the effects of hydrogasifier pressure, temperature and reactive gas mixture on methane and total product gas yields, product gas composition and carbon conversion;
- Bench-scale testing to determine the L to D ratio of the hydrogasifier;
- Tip burner concept design and testing;
- Algae recycle testing and verification.

Figure III-1 Bench Scale Test Reactor Drawing

Duall Wall Reactor Cross Section



Phase II Development Engineering: Phase II will focus on developing the preliminary work to support the third phase pilot test program. The tasks will include RX design and vendor selection, site layout and selection. WP will incorporate bench-scale test results into the system design and expand the Engineering Package developed in Phase I. Work will begin on conducting preliminary engineering for the engineering-scale test facility (pilot testing) to be constructed in Phase III. Preliminary Design Bases and preliminary equipment specifications for major process equipment required in the Phase III engineering-scale test facility will be developed. Balance of plant engineering will be performed and basic engineering drawings developed including: plant electrical one-line drawings, balance of plant flow diagrams and a conceptual layout for the engineering-scale test facility installation. Both process and balance of plant engineering will be based on a plant size confirmed by Phase II bench-scale testing. Additional work will be done to update commercial engineering work completed in Phase I.

Phase II Economics Investigation: The economic, business and commercialization plans will be updated and expanded to assess the technical and commercial viability of the concept. Phase II will include a thorough investigation of the economic viability of the Advance Hydrogasification Process (AHP). The investigation and analysis will consider the market conditions and will weigh alternatives against the AHP. The investigation and reports on economics and market will consider the likely scenarios for various fuels and potential energy solutions. This work will focus on the needs and considerations of US electric utilities.

Phase III Engineering-Scale Testing: While the focus of Phase III is on the construction, startup and operation of an engineering-scale test facility, it is anticipated that some additional bench-scale testing may be required to support design changes and investigate startup issues. This testing will be conducted, as necessary, using the facilities constructed for Phase II testing. The preliminary Test and Startup Plans, developed in Phase II, for the engineering-scale test facility will be refined and supplemented based upon final equipment selections, system engineering and balance of plant design. Final site permitting and other EHS work will be done at the start of Phase III.

Phase III Advanced Engineering Development and Field Tests: The Process Design Package (PDP) will be prepared and detailed system engineering, procurement and installation work will be conducted. Engineering interfaces with the power plant site will be established to integrate the engineering-scale test facility into the site and generating plant. The final engineering-scale test facility will operate under the same design conditions as a commercial-scale facility.

Once constructed, the engineering-scale facility will be taken through startup and tested to confirm design bases and process performance calculations. The hydrogasifier will be tested extensively as an integrated system. The produced gas will be used at the plant site, or depending on technical success, placed in gas pipelines for transport to other power generation facilities.

Phase III Market Analysis: Analysis will be completed in Phase III based on testing and research to position the AHP within a context of commercial relevance.

4. Re-Scoped Work

The planned work, as noted above, follows the plans in the proposal to DOE. The changes and modifications center around the new revised, and simplified process. Changes have been accommodated in the WBS for phase two and resources & talent added through new team members and additional funding to support the algae recycle part of the program.

While the work plan for phases two and three remains intact the potential for completing design work on a commercially viable process seems to be considerably advanced. AHP is a project targeted at electric generation options after 2010. The first phase of the project has been completed with sufficient progress to support that goal. In many areas the project is further advanced than anticipated at this stage, however major obstacles and challenges remain. The work scope in place for phase two is structured to address many challenges and opportunities.

“IF YOU CAN DREAM IT YOU CAN DO IT.” WALT DISNEY

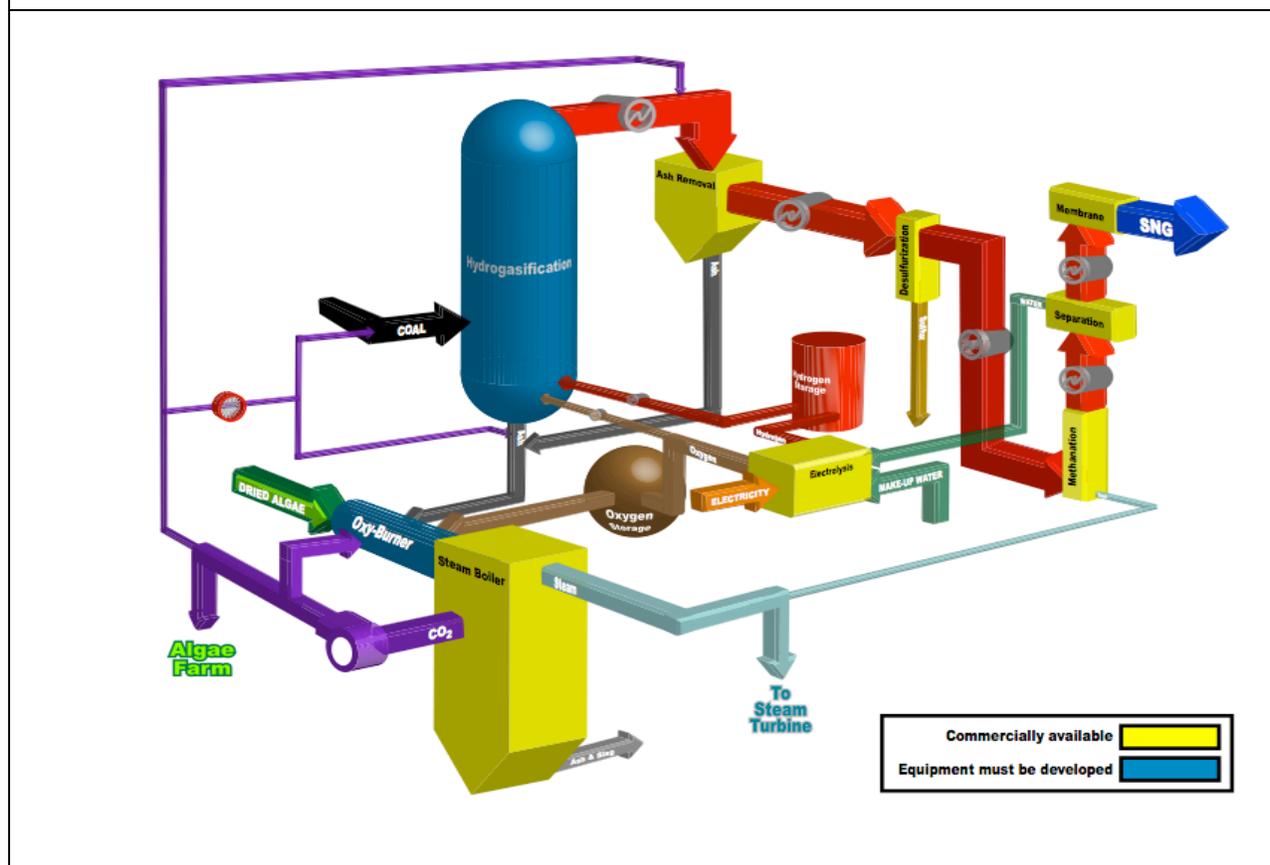
IV. Hydrogasification system evaluation

1. Proposed Technology/Methodology

Process Description: In the Advanced Hydrogasification Process (as shown in Figure IV-1), coal is gasified in the presence of hydrogen to a methane rich fuel gas stream. Hydrogen enters the hydrogasifier reactor (HG) and mixes with coal, converting a high percentage of the carbon in the coal to methane. The conditions required to maximize this conversion are the subject of the proposed program of work. Several options remain open to be resolved based on further technological analysis and testing, and economic trade-off analysis. Options include – 1) The use of a methanator to convert CO₂ to increase methane production with the use of additional hydrogen 2) the utilization of the algae recycle process to use the CO₂ to produce a fuel feedstock or 3) some combination of these options.

The product stream is transformed in a commercial methanation unit (MeT) into a SNG stream meeting pipeline requirements. The carbon content of the hot gas stream is adjusted to assure that the majority of the hydrogen present in the input stream is used to convert CO and CO₂ into methane. The product stream is cooled prior to methanation allowing the MeT to operate at lower temperatures commensurate with commercially available equipment. Remaining char from the reactor and waste heat from the process are used to produce steam for electricity co-production. Finally there is a polishing step, where the SNG is upgraded, as required, to pipeline conditions.

The process integrates the key elements of the initial proposal with several significant upgrades of particular interest to western electric power producers. The process consumes rather than releases CO₂, the process has a renewable option and the process utilizes current technology, with the exception of the reactor that has been tested in Japan but not fully developed. Finally, an additional feature has been added at NETL's request that allows electric producers to reduce CO₂ emissions further by adding carbon recycle to stack gas exhaust.

Figure IV-1 – Artistic rendering of proposed AHP process flow.

2. System analyses conducted

During the course of this study, two hydrogasifier approaches were identified. The first, Option 1, utilized the sensible energy contained in a high temperature hydrogen recycle stream to balance the gasifier energy input such that a 1,500°F outlet temperature was maintained. Option 1 also utilized high temperature solid sorbents for H₂S and CO₂ removal and recovery. The second approach, Option 2, balanced gasifier energy input and maintained gasifier effluent temperature by partially oxidizing (combusting) a small portion of the gasifier hydrogen feed stream with nearly pure oxygen. Option 2 used a commercially available low temperature desulfurization process. The analysis by the team examined the merits and detriments of the two options. Only one approach could be reasonably pursued under this grant, although both had merit. In both cases, the performance of a conceptual gasifier was assumed. The risks to Option 1 and Option 2 in terms of technical, performance, development, and economics associated with the options were an integral part of the evaluation. Further, both options required the developmental coal feed and ash removal methodologies. As a consequence of this

commonality, the hydrogasification approach of either option was not a factor in determining which option is the best choice for going forward. It was the downstream equipment that determined the path going forward.

Option 1 would use a high temperature (1,600°F) gas recycle loop to provide the gasifier with energy. Fabricating mechanical equipment to compress gas at this level of elevated temperature is very difficult because the metallurgy required is difficult to apply. There is no commercially available equipment for this high temperature gas compression service and development of such materials can require up to 10 years to reach commercial maturity. In a practical application, the gasifier recycle gas stream would have to be cooled, compressed, reheated, and then routed back to the gasifier. However, there is no heat source with high enough temperature to provide the energy to reheat the compressed recycle stream to 1,600°F. This concept of providing the gasifier with energy input through a high temperature gas recycle would have to be rethought in order to proceed with Option 1.

Option 2 would use the energy generated from the exothermic partial oxidation of hydrogen by nearly pure oxygen to balance the gasifier energy input and maintain a suitable gasifier exit temperature. This method of partial oxidation is typical of many commercial and developmental gasification methodologies including hydrogasification methodologies in past and current development. However, this technique introduces additional cost and auxiliary power load requirements for an oxygen source (air separation unit, or electrolysis) as well as a decrease in overall system efficiency. The use of oxygen – as an oxidizing agent -- is counter-productive to the conversion of coal to SNG; the combustion, or oxidation, process results in irrecoverable second law losses. The fundamental objective of a pure hydrogasification process would be the direct reduction of coal by hydrogen to CH₄ without the use of an oxidizing agent. The use of oxygen in a hydrogasifier has many shortcomings, however, it is a convenient and a legitimate method of balancing the gasifier energy needs such that a viable gasifier effluent temperature can be maintained. Also, the addition of oxygen to the hydrogasifier reaction vessel and the subsequent partial oxidation of hydrogen are technically and mechanically feasible.

As discussed above, Option 1 requires a high temperature gas recycle stream to balance the energy input to the gasifier. High temperature solid sorbents have been identified as the method to desulfurize the hot gas prior to it being compressed and recycled. High temperature solids also are being used to remove and recover CO₂ from the hydrogasifier stream. Both the H₂S and CO₂ removal and recovery processes require that solids be exposed to the high temperature gasifier effluent. In an absorber vessel, the solids react with the either H₂S or CO₂ to form an intermediate solid component. The spent or reacted solids are

mechanically transported or fluidized with a gas stream to a regeneration vessel where either the H₂S or CO₂ is liberated (at high temperature) and the solid sorbent regenerated. The hot solid sorbent is then returned to the original absorber vessel that is in contact with the hot gasifier effluent. Handling and cooling high temperature solids in a regenerative process has been troublesome when viewed from a historical perspective. Past work with the CO₂ Acceptor Process and the moving-bed/transport-bed zinc-based desulphurization processes investigated by the DOE are testimonies to this point. Typical problems encountered with the use of high temperature solids in this type of regenerative loop include bed agglomeration, sintering, and attrition. The solids are difficult to move from vessel to vessel and typically suffer due to an inability to properly control temperatures throughout the solid beds. There have been some recent successes in this area but high temperature solid sorbent processes have a long track record of infeasibility (The CO₂ Acceptor Process was abandoned by CONSOL primarily because they could not manage the high temperature movement and handling of CaO and CaCO₂ solids.)

Option 2 requires the use of an oxygen burner to convert the unconverted coal from the gasifier - char - into a CO₂-rich gas stream. This action introduces additional costs and auxiliary power load due to the oxygen requirement. Alternatively an oxygen-blown gasifier could be used. However, the same issues exist with this option as well. Another alternative would be viewing the gasifier char as a “fuel product” and to sell it to a local power generator.

Option 1 assumed 99 percent carbon conversion in the hydrogasifier. This number is very ambitious and doubtfully achievable. A survey of relevant published literature indicates that 60 to 70 percent carbon conversion is likely the attainable upper-end for a single pass through a hydrogasifier. Therefore, Option 1 would have the same issues as Option 2 when it came to char disposition. It was concluded that the gasifier and char disposition from each hydrogasifier option are of equal merit or detriment and not an indicator of the potential success or failure of a program centered on them. Option 1 relies on high temperature solid sorbents for desulphurization and CO₂ capture. It is well known that operation with high temperature solids is very difficult. Option 1 also requires a 1,600°F gas recycle stream but has no method to produce such a stream from commercially available mechanical equipment. Option 2 relies on the partial combustion of hydrogen in order to fuel the gasifier reactions. This introduces inefficiencies and cost. However, the use of an oxidant in a hydrogasification process is technically and mechanically feasible and offers less risk than the use of high temperature solids and high temperature gas recycle. Option 2 was chosen as the option for the APS Hydrogasification process.

Selection of system for further development

Coal, hydrogen, oxygen and a CO₂ recycle stream are all fed into the hydrogasification reactor. A minimal amount of oxygen is introduced to help in providing the required gasification temperature of approximately 1600°F. The oxygen will be introduced with the hydrogen to partially oxidize the hydrogen, producing a hot hydrogen/steam stream, which will come in contact with the coal transported into the gasifier by CO₂. The hot hydrogen will begin the hydrogasification reaction with the coal. Approximately 60 to 70% of the coal carbon will gasify with approximately 30 to 20% of the coal carbon remaining in the solid stream leaving the gasifier. The developed process simulation is based on a carbon conversion of 70%. The solids leaving the gasifier will be combusted with an O₂ stream in order to generate a nearly pure CO₂ stream. The generated CO₂ stream will be split into 2 streams, with approximately one half being used to transport the coal and char, and another half being used to adjust the H to C ratio going to the methanator. The CO₂ stream going to the gasifier will be cooled and compressed and reheated prior to being re-introduced into the gasifier with the coal and ash.

The CO₂ slip-stream will be cooled and compressed and mixed with the gas stream leaving the gasifier prior to the methanator. Since there will be some excess O₂ left after combustion, hydrogen will be introduced to catalytically combine with the remaining O₂ and SO₂. The mixed stream will be cooled and sent to a CrystaSulf desulfurizer process and then onto a methanation block consisting of a series of heat exchanger and catalytic reactors. The methanator catalyst requires a very low sulfur level to prevent poisoning. The raw SNG leaving the methanation block will be dried and sent to a hydrogen membrane separation unit. This will remove most of the hydrogen while maintaining the SNG at high pressure. The separated hydrogen will be used to remove the excess O₂ from the oxygen blown Char combustor.

Hot raw fuel gas exits the gasifier at approximately 1600°F/990 psia. The fuel gas and residual char leaving the Radiant Raw Gas Cooler are cooled to 655°F raising high-pressure steam. High pressure steam is also generated in the evaporative surfaces of the Char Combustor and the Hydrotreater and Methanator gas coolers. High-pressure steam is superheated in the Char Combustor and utilized in the steam turbine generator (STG) to produce electric power.

The team will explore various alternatives within the above outlined process. Variants on flows and percentage, even changes in equipment may produce greater efficiencies or reduce cost. For example including the algae recycle process may dictate changes in flow. There also may be alternatives based on the circumstances of location, supply and product needs.

Hydrogasification Reactor

The design of the hydrogasification reactor is based on the collaborative ideas of a team endeavoring to produce SNG from western coal. The root concept of this design is the exploitation of the hydrogen-coal reaction to produce methane (CH₄) induced by the moderately elevated temperatures (>1,500°F). This reaction is typically referred to as hydrogasification. A preliminary concept for a commercial-scale hydrogasification reactor is described below. The proposed operating conditions for this reactor are 1,000 psia and 1,500°F.

An illustrative sketch of the hydrogasification concept is shown in Figure IV-2. The gasifier will be a refractory-lined vessel with internal dimensions of about 5 foot diameter and 50 feet in height. The bottom third of the gasifier will be shaped with steel and refractory blocks such that a converging-diverging section is affected. These overall internal dimensions of the gasifier would yield an approximate volume of 900 cubic feet.

Four partial oxidation burners will be located on the extreme top of the vessel. These burners will fire hydrogen in the presence of an oxidant consisting of 99.99+ percent oxygen. A minimum amount of hydrogen will be burned – generating a small amount of water vapor -- yielding a high temperature (~1,600°F) hydrogen-rich gas stream. The burners will be arranged tangentially from one another at 90 degree angles. The burners will be cooled by a circulating water system with external indirect heat exchange to cooling water or another suitable heat sink.

Due to the high reaction rates and laminar flame speeds, the startup of the gasifier may employ CH₄ rather than H₂. One of the tasks in phase two will be to explore manufacturers available to supply a burner, which is capable of starting up on CH₄ and loading up to the pressure. The burner can be designed to accommodate multiple passages for both CH₄ and H₂ fuels – possibly to be burnt simultaneously during the transfers. Also, it is possible to design multiple plenums and orifices in the same burner to operate H₂ at low pressures and high pressure conditions. One common burner for startup, shutdown and full load operating condition is possibly available from several manufacturers today. However, it may not be up to the pressure of 1000 psi. Gas turbine manufacturers can operate their H₂ burners at pressures up to ~300 psi.

The hydrogen-rich gas stream will be directed downward into the gasifier. Pulverized coal will be injected perpendicularly into the hydrogen-rich gas stream. Four coal injectors will be used. The injectors will be arranged 90 degrees from one another. The injectors may or may not be cooled with an external cooling water loop similar to that of the hydrogen partial oxidation burners.

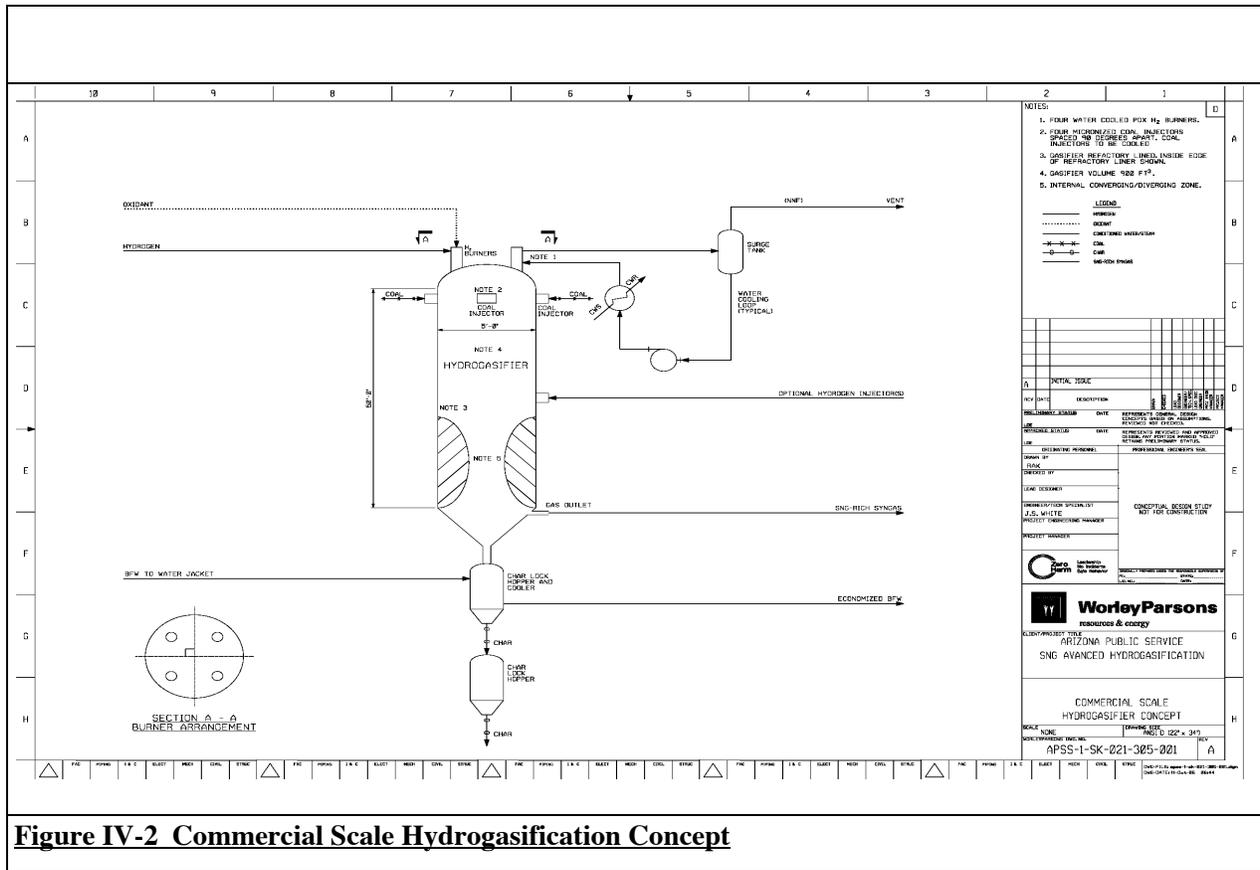


Figure IV-2 Commercial Scale Hydrogasification Concept

Hydrogen will contact the coal resulting in the production of CH₄. The reaction is exothermic and will result in a bulk gas temperature increase. Downward motion of the gas and solid particles through the reactor will approximate plug-flow in character. It is anticipated that 70% of the coal can be hydrogasified in this manner. The remaining 30% would exist as char and primarily consist of carbon with small amounts of hydrogen, nitrogen, and sulfur present.

An optional hydrogen injection port has been shown in the drawing. The injection port is approximately half way down the reactor vessel. It is envisioned that there is the possibility that additional CH₄ could be produced by reacting hydrogen with the un-reacted “char” in the bottom section of the gasifier vessel.

Gas and particles will travel the length of the vessel, converging and accelerating, and then diverging and de-accelerating in the bottom third of the reactor. This motion is intended to focus the path of the pulverized particles towards the bottom of the gasifier and into the char hopper system. Gaseous components, such as CH₄, H₂, N₂, H₂S, and HCl, will exit from an outlet nozzle located at the terminus of the diverging zone. The converging-diverging zone is shown because there is some concern as to the ease with which the pulverized particles will be separated from the gas phase. The concern is that the

individual solid and gas phases would be indistinguishable. This will make phase separation very difficult. Other possible separation strategies include internal baffling, and/or the use of ceramic or metallic candle filters. A combination of cyclone and candle filters has been assumed in this design. A char hopper system is illustrated at the bottom of the hydrogasifier. The first char lock hopper is designed to cool the char to perhaps 500°F. The second char hopper is for depressurization to a secondary process.

3. Evaluation of Systems Performance

The team took a methodical approach to determining the best alternative process to proceed with. The alternatives and their associated options were developed amid discussion, analysis and debate. As the alternatives were developed they were compared to each other and the original loop design. Technical discussions were frequent and backed up by modeling, analysis and ASPEN data. Weekly calls were used to direct the discussion and group meetings were established for more formal face-to-face presentations culminating in a “decision” meeting. Even after an alternative had been chosen as the basis of further work options continued to be discussed and examined.

4. Selection of system for further development

The process that was selected will go through further analysis and modifications during the course of Phase II. Challenging our assumptions has become an integral function of the team. There are, however several key aspects of the Hydrogasification technology as currently conceived that continue to encourage enthusiasm within the Team.

The hydrogasification process offers several inherent advantages over other gasification processes. The reaction produces a large fraction of methane in the hydrogasifier. Hydrogasification requires a lower reaction temperature than most other coal gasification processes, increasing thermal efficiency and reducing the potential for operating problems associated with ash slagging. Additionally the hydrogen-carbon reaction is exothermic. The hydrogasification process will produce higher level BTU gas suitable for introduction into existing natural gas pipelines and existing gas turbines.

The hydrogasification process as developed by the AHP team includes a number of alternative paths including providing the hydrogen from renewable sources (wind), variations on the co-generation boiler, and algae recycle as a means of carbon capture and re-use. The consideration and process design allowing for alternative options expands the opportunities for the AHP process to succeed within a variety of circumstances.

*“ANYONE WHO RELIES UPON AUTHORITY USES NOT HIS UNDERSTANDING, BUT HIS MEMORY.”
LEONARDO DA VINCI*

V. Phase I Development Work

1. Phase One Evolution

During Phase I, the APS/SNG Team resolved significant challenges and moved from a raw concept to a viable AHP process and technology. Several advances were made in the 1st Phase including creation of a highly efficient SNG process, the elimination of a CO₂ stream, reducing the uncertainty of the back stream process, reducing high temperature, high pressure gas stream recycle, a new coal feed & coal sizing, a once through reactor, commercial pressures and temperatures through-out the process and a multiple of deliverables analyzing and describing the process.

During Phase I, the project team created a simplified chemical process (reducing risk and cost) that can incorporate a number of options that could be adapted to specific regulatory requirements, applications and geographic considerations. Three avenues for hydrogen supply were identified (wind, existing utility capacity, coal) and evaluated. Any of these avenues appear to be viable process priorities either alone or in combination. Hydrogen delivery considered use of a pipeline for wind or the electric grid for site hydrogen/oxygen production. TGA testing by GTI confirmed that traditional coal gasification tests may lead to excessive reaction time conclusions. Phase I identified that coal particle size, hydrogen temperature, and rapid rate of temperature change are critical to hydrogasification reactions. SEM analysis demonstrated that coal particle surface area will be substantially increased when reaction conditions are correct. Similarly the CO₂ capture and use now has several viable paths and alternatives including within the SNG process or tied to the electric production process whether coal or combined cycle. AHP meets the one critical factor to the selection of any new coal process - the identification of a control mechanism for carbon dioxide releases.

The rich research history created by prior DOE hydrogasification programs has made a substantial contribution in Phase I. Phase I work was also significantly enhanced by the research results from the Japanese ARCH (Advanced Rapid Coal Hydrogasification) Project, which terminated in 2002 because of the presumed abundance of low cost natural gas reserves.

The team is proceeding in Phase II to test reactor kinetics, evaluate the economics of the process, expand the development of CO₂ recycling and prepare the preliminary work to proceed to Phase III. The success in creating a complete process model in Phase I, now proceeds to reaction kinetics to complete the modeling required to justify the investment required to build the engineering scale system. The AHP process that has been developed and is now proceeding to reactor testing is a process that includes significant flexibility and long-term sustainable production. The proposed process can allow for a

significant energy contribution from SNG created from abundant coal reserves and the capture of carbon dioxide in a renewable process with renewable hydrogen and recycle of carbon through algae. The process not only uses coal without greenhouse gas emissions, it can be configured to considerably stretch US fuel supply. Once commercial, the process can produce a stable supply of “clean” fuel from a domestic western coal over a considerable length of time.

2. Accomplishments in Phase I

Phase I Objectives – The Objectives of Phase I were completed with the exception of sorbent characterization; that work was replaced with work on the Bench Scale Test reactor design, modeling and equipment purchase.

- Characterization of reactivity of candidate coals; Complete
- Characterization of sorbents.....Dropped, replaced with Bench Scale testing work
- Design Basis Criteria –.....Completed
- Conceptual Process Design –.....Completed
- Major Equipment List – Completed
- Cost Estimates – Completed
- Trade-off and Sensitivity Studies – Completed
- Techno-Economic Evaluation –.....Completed
- Investigation of Recycle through algae of carbon..... Completed

Significant Findings –

- The volatilization of the coal with the smaller particles was an advantage not envisioned at the start of the project.
- Addition of algae recycle creates flexibility in the process that opens up a number of new variables. The algae recycle also significantly extends the carbon removed from the process as fuel.
- The work done on wind renewable, electrolysis, storage and other aspects of wind to hydrogen were not previously available.

Conclusions – The conversion of coal to SNG (methane) using hydrogen appears to be a viable source of competitive fuel for the US energy infrastructure, offering a potentially renewable process with no requirement for CO₂ sequestration. The proposed AHP process provides a long-range utilization of coal in a stable, sustainable and environmentally acceptable manner.

Developments – The AHP process was significantly refined in Phase I to a more efficient, largely commercially available, and environmentally friendly process. The process as currently envisioned incorporates flexibility linked to a variety of sustainable alternatives.

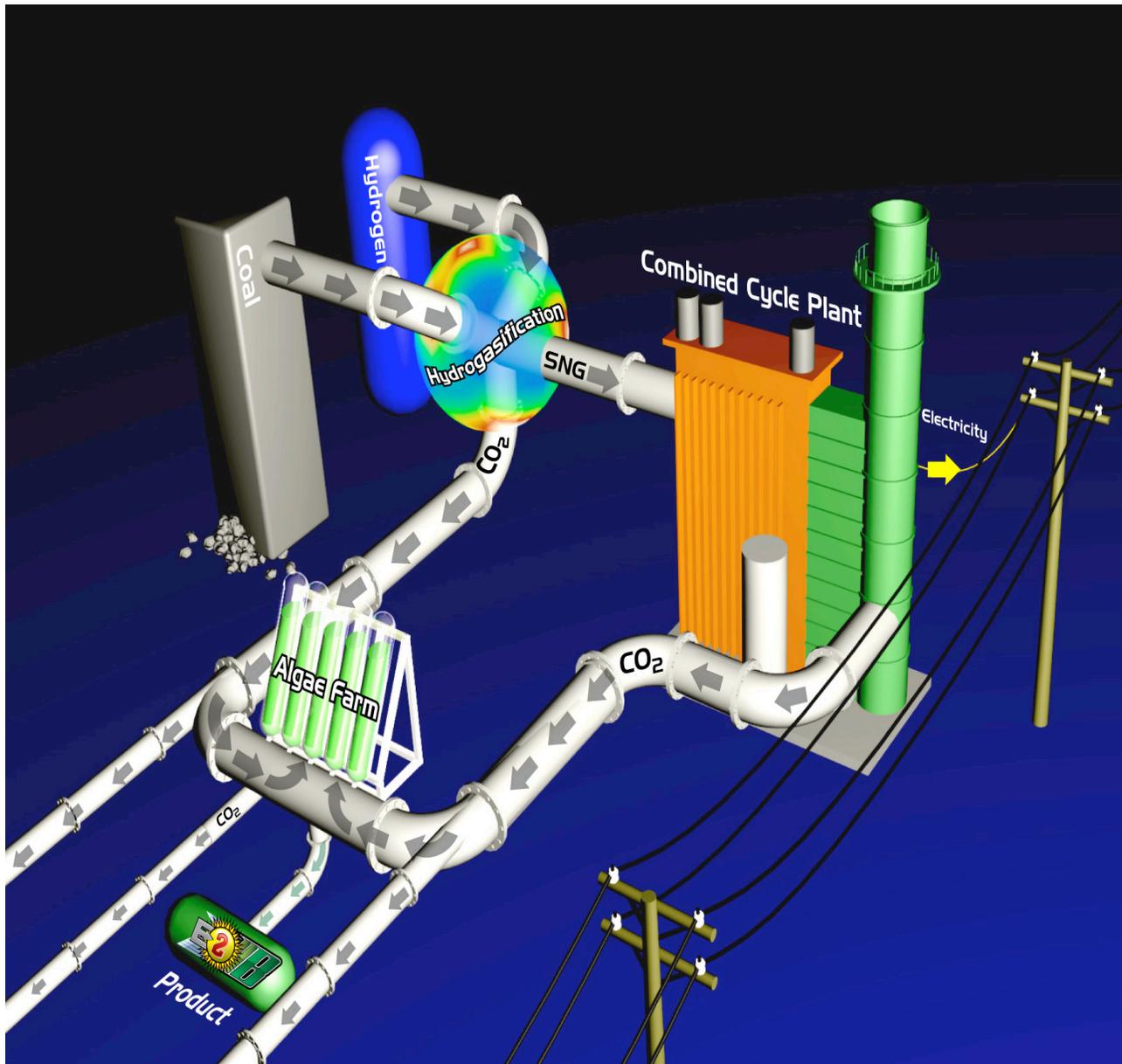


Figure V-1: Graphic Representation of the AHP Process

3. Work Program and Structure for the Project

Work Organizational Description: The program of work has utilized a structured Project Management format, often referred to as an Earned Value structure. This structure has been adhered to both conduct the engineering of Phases I and II and to construct an engineering-scale facility in Phase III. Earned Value Management (EVM) is a refinement of the earlier “waterfall” project management approach to large construction projects. The key ingredients to this approach are a clear plan at the start that includes defined product, time frame and cost. A Project Management team is placed at the center of the project. A Work Breakdown Structure (WBS) is built to structure the work. Contracts are tied to the WBS and include payment clauses based on clear defined deliverables. The AHP team has a great deal of project management experience using this system and structured the project within an EVM framework adding refinements developed by members of the team over the past 40 years of project management experience.

Successful project management includes many interconnected facets including strict deliverables, schedule focused controls, frequent orderly communications and rigorous tracking of measurements. The AHP project has included and vigorously followed those tenets. The project use “work arounds” to effectively keep the schedule of work moving in spite of needed redirection of work. The schedule from the start was fast tracked in order to be ready for the pitfalls and challenges inherent in R&D work. Work was also frequently directed on parallel or even triple paths to maintain progress and most efficiently utilize scarce resources. And finally communication was built into the project from the start. Key measurements were tracked and frequently communicated to the team. Weekly reports and all-team conference calls, along with almost daily response and feedback kept project management and team members advised of progress and challenges – both technical and work task.

The AHP project has utilized a fast track approach to the scheduled work and tasks. By pressing forward it is the intention of the Project team that AHP will be commercially viable for the next generation of electric power plants developed in the US. To be positioned for the next “round” of power station development the AHP project will need to have tested and “proven” technical availability by approximately 2010. In addition to technical success the project team is tasked with demonstrating an economic or market analysis positioning AHP.

Internal Organization: The project was organized around a project management format. The lead for the Project is the APS Program Manager. Reporting to the program Manger is a project Manager. The Project Manager has responsibility for quality, cost and schedule of the proposed Program work. Also reporting to the Program Manager are personnel responsible for operations oversight, environmental,

health, safety and regulatory compliance, and financial/operational audit. These personnel report to the Project Director (independent of the Project Manager) to provide operational checks and balances. A Technical Advisory Committee consisting of key technical experts providing independent oversight of the experimental program and process development will advise the Project Director. The team has five Participants who are “owners” of the program and provide support. There are also a number of contractors who work for the project under contracts with APS. The project reports to NETL as the guiding organization/lab for the DOE.

Management Tools - Program management personnel utilize a written set of numerical goals and objectives, pre-set scope and clarified assignments, and an integrated and linked project schedule. Personnel work from pre-set assignments/tasks that have definitive scope, committed due dates and a described product deliverable. Regularly scheduled meetings (often conference calls to save cost) that address progress, conflicts, interfaces, and deliverables will be utilized.

PRINCIPALS

- IF UNDERSTANDING WERE EASY, SOMEONE ELSE ALREADY WOULD HAVE DONE IT.
- IF YOU FOLLOW IN SOMEONE ELSE’S FOOTSTEPS, YOU MISS THE PROBLEMS REALLY WORTH SOLVING
- EXCELLENCE IS BORN OF PREPARATION, DEDICATION, FOCUS, AND TENACITY - COMPROMISE THESE AND ONE BECOMES AVERAGE
- EVERY SO OFTEN, LIFE PRESENTS A GREAT MOMENT - ONE MUST DECIDE TO STOP OR GO; A PERSON LIVES WITH THESE DECISIONS FOREVER.
- EXAMINE EVERYTHING; NOT ALL OF IT IS AS IT SEEMS OR AS YOU HAVE BEEN TOLD
- IT IS EASIER TO LIVE WITH A DECISION BASED ON AN HONEST SENSE OF RIGHT AND WRONG
- THE WORST DECISION IS TO GIVE UP

JOHN CHATTETON, SHADOW DIVERS

VI. Gasification System Technical Summary

1. APS AHP Process

The APS AHP is a newly developed integrated process for the co-production of substitute natural gas (SNG), biofuel, and electrical power from western coals, with near-zero CO₂ emission. As shown in Figure VI-1, as-received Fruitland formation coal from northwest New Mexico goes to a hydrogasifier where it is treated with renewable hydrogen at a temperature of about 1,600°F at a pressure of 1,000 psia to produce methane-enriched gaseous products. The unconverted coal (primarily carbon and mineral matter) is withdrawn and sent to a low pressure oxygen combustion process (ash combustor), where CO₂, the main gaseous product, and slag are produced. A portion of this CO₂ stream is compressed and recycled to convey the coal into the hydrogasifier. The remainder is fed to the algae farm. The gaseous products from the hydrogasifier are cleaned (fly ash, mercury, and sulfur are removed) and sent to a multi-bed methanation process to further convert CO and CO₂ into CH₄. The raw SNG leaving the methanation process is cooled, flashed to remove water, dehydrated to remove residual water, and passed through a separation process to remove extra hydrogen. The finished SNG is compressed and injected into the El Paso natural gas pipeline system.

A minimal amount of oxygen is introduced to help in providing the required gasification temperature of approximately 1600°F. The oxygen will be introduced with the hydrogen to partially oxidize the hydrogen, producing a hot hydrogen/steam stream that will come in contact with the coal transported into the gasifier by CO₂. The hot hydrogen will begin the hydrogasification reaction with the coal. Approximately 60 to 70% of the coal carbon will gasify with approximately 30 to 40% of the coal carbon remaining in the solid stream leaving the gasifier. The developed process simulation is based on a carbon conversion of 70%.

The AHP process was developed to utilize the abundant coal supply in the US and renewable hydrogen to make the SNG (CH₄). Coal provides the carbon for the process. Wind energy can be used to power an electrolyzer that splits water into oxygen and hydrogen needed for the hydrogasifier. Algae, fed on carbon dioxide emissions, are dried and can be used either as an additional fuel source or as a feedstock for biodiesel and cattle meal production. The role for each of these concepts, or the utilization of alternative concepts or a combination thereof, is under continuing evaluation.

The resulting system could be placed at a mine mouth location in the Four Corners area, far from load centers, with decent wind energy resources (or other source of hydrogen). The SNG can be transported

by natural gas pipeline to highly efficient, clean natural gas combined cycle (NGCC) power plants. Efficiency will be gained by eliminating transmission line losses and by providing a reliable source of natural gas that is so critical for meeting peak load demands in the West. Electric power produced in the AHP process and the SNG used in NGCC power plants meets the stringent new California long-term power purchase performance standard for greenhouse gas emissions. The assessment from the Western Governors' Association indicates that the Governors supported advanced coal technologies, such as hydrogasification, as an important resource for the future. Recognition of the importance of diverse and reliable sources of electric power that reduce emissions is clearly growing rapidly in the western US.

The performance targets for the AHP include:

- • A process efficiency greater than 50%;
- • Production of SNG at a cost of \$5 - \$10/MMBtu;
- • Capture of more than 90% of emission from a coal-fired generating unit;
- • Reduction in water use by least 50% below that of a comparable gasification or synthesis gas methanation process plant;
- • Ability to accept hydrogen as a supplemental source of energy;
- • Use of low-rank western coal;
- • Co-production of electricity;
- • Evaluation of an algae process for CO₂ recycle and preparation of a test protocol for the algae process

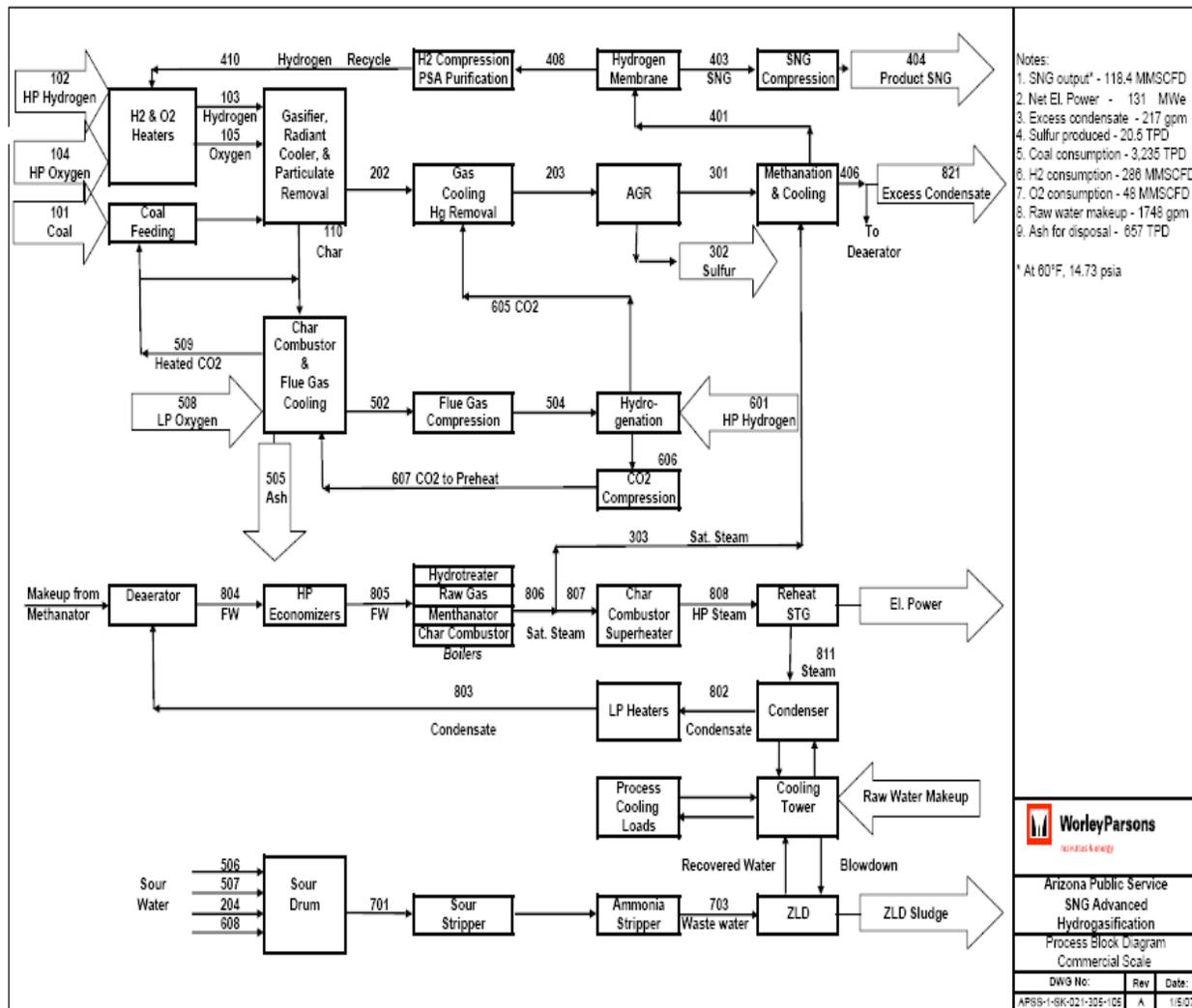
2. Process Modeling

Including the process shown in Figure I-1, two processes were the focus of the ASPEN Plus modeling. The process presented as Figure VI-1 has the option of using a methanator to transition excess CO₂ of the burner to methane.

The solids leaving the gasifier will be combusted with an O₂ stream in order to generate a nearly pure CO₂ stream. The generated CO₂ stream will be split into 2 streams, with approximately one half being used to transport the coal and char, and another half being used to adjust the H to C ratio going to the methanator. The CO₂ stream going to the gasifier will be cooled and compressed and reheated prior to being re-introduced into the gasifier with the coal and ash. The CO₂ stream going to the methanator will be cooled and compressed and mixed with the gas stream leaving the gasifier. Since there will be some excess O₂ left after combustion, hydrogen will be introduced to catalytically combine with the remaining O₂ and SO₂. The mixed stream will be cooled sent to a CrystaSulf desulfurizer process, and then onto a methanation block consisting of a series of heat exchanger and catalytic reactors. The methanator catalyst requires a very low sulfur level to prevent poisoning. The raw SNG leaving the methanation block will be dried and sent to a hydrogen membrane separation unit. This will remove most of the hydrogen while maintaining the SNG at high pressure. The separated hydrogen will be used to remove the excess O₂

from the oxygen blown Char combustor. Hot raw fuel gas exits the gasifier at approximately 1600°F/990 psia. The fuel gas and residual char leaving the Radiant Raw Gas Cooler are cooled to 655°F raising high-pressure steam. High pressure steam is also generated in the evaporative surfaces of the Char Combustor and the Hydrotreater and Methanator gas coolers. High pressure steam is superheated in the Char Combustor and utilized in the steam turbine generator (STG) to produce electric power.

Figure VI-1 Process without Algae



Hydrogasification Processing Block Arrangement – APS AHP “CO₂ into Methanator” Process.

This is straightforward and has the advantage of simplicity. However, converting CO₂ into CH₄ through the methanation process is not very energy efficient. Extra hydrogen (stoichiometry ratio of H₂:CO₂ as 4:1) is required in this process by giving water. The first set of figures below diagram this process. The

critical advantage of this simple process is that it removes CO₂ from the power producers' liabilities. The liability of CO₂ – financial, legal and social – cannot be over stated. US electric utilities have been through several severe set backs due to real or perceived by-product liability. From the first space flights naming Four-Corners as covered in coal smoke to the on going spent fuel crisis the industry has many hard learned lessons regarding the liability of by-products. The AHP process offers an avenue that produces pipeline quality gas to fuel CC units while avoiding the enormous risk posed by the other current technologies. The long held belief is that the preferred option is to not make it than to try to figure out how to clean it up.

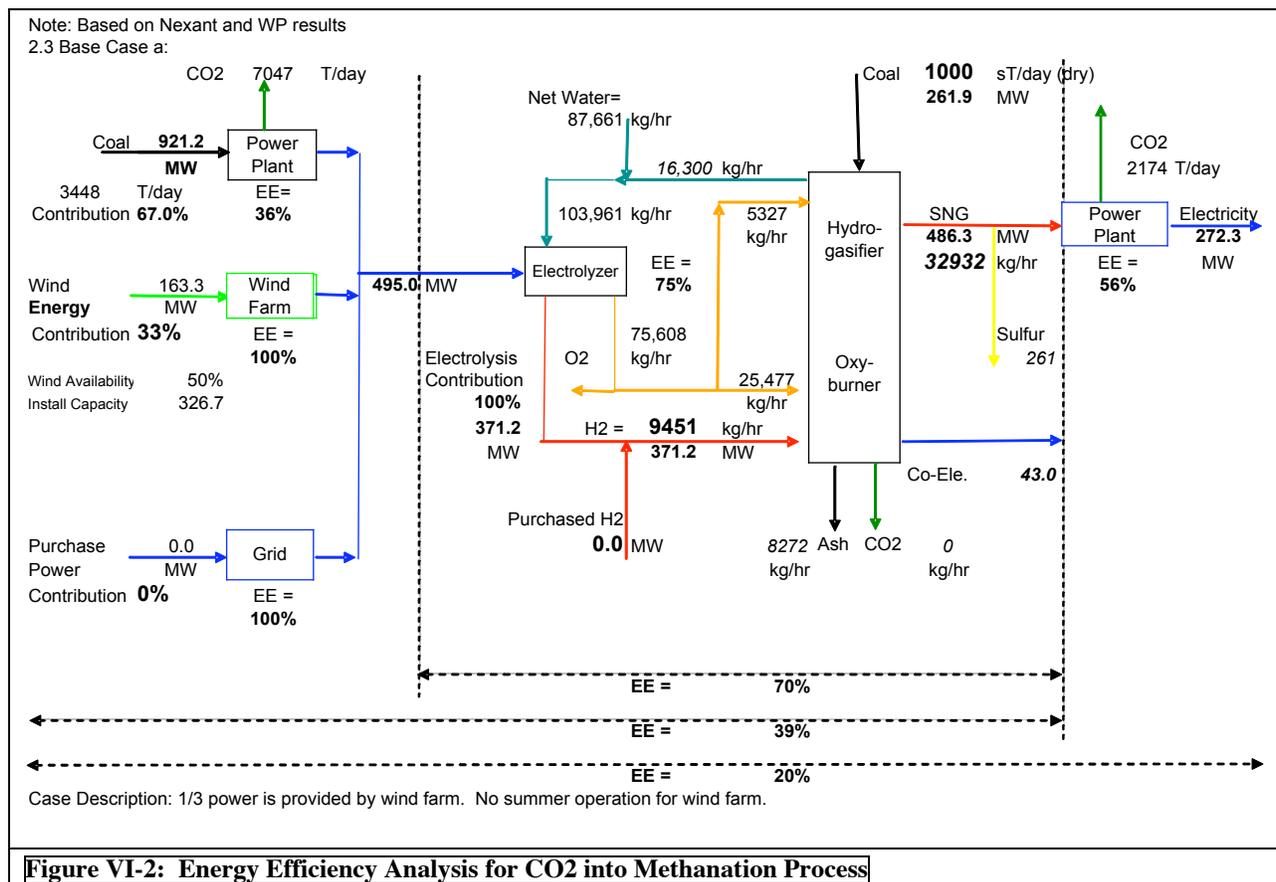


Figure VI-2: Energy Efficiency Analysis for CO₂ into Methanation Process

Figure VI-2 gives energy efficiency analysis of this process. The graph is a snapshot from an Excel simulator with an assumption that one third of electricity required by electrolysis for hydrogen supply is from wind farm. Different scenarios were studied for EE comparison. The main advantage of the APS AHP process is the capability to use wind electricity. Due to the challenge of electricity storage, especially for a highly fluctuating supply of wind electricity, the AHP process provides a way of storage by converting

it into H₂ and further to SNG. As a starting point, off-peak electricity may be used to speed up the process development due to the limit of current wind electricity supply. Besides, nuclear power and the direct coal to hydrogen technology are also under consideration.

Figure VI-3 (same as Figure I-1) presents the algae integrated process. The produced CO₂ 20 MMSCFD from oxy-boiler will be introduced into Algae farm instead of methanator like previous option. The data further illustrates that APS AHP process produces much less CO₂ than the regular gasification process, where to get desired H₂/CO ratio for methanation step, a significant amount CO₂ is produced during the WGS process. It should be noted also that the algae may also be utilized at the electric generation plant to further reduce CO₂ introduction to the atmosphere by subjecting waste flue gas to the algae recycle. The AspenPlus™ process simulation model developed for this AHP process shows that from 1,000 short-tons/day (37,799.4 kg/hr) of dry Fruitland coal, the process produces 25,900 kg/hr of SNG with an assumed 70% carbon conversion [8-10]. The process requires about 7,333kg/hr hydrogen and 25,500 kg/hr oxygen. Besides the SNG, the process also produces 261 kg/hr of sulfur and exports about 36 MWe of electric power. The CO₂ generation rate is about 400 ton per day, which will be fed to an algae farm, which will produce about 20 MWe dry algae.

Table VI-1

<u>The design basis for the AspenPlus™ simulation model is presented below.</u>	
End Product Required:	Substitute Natural Gas (SNG) for export to pipeline
Gasification Processes:	Hydrogasification and Ash Combustion
Coal Feed Rate:	1,000 stpd (dry basis) or 1,078 stpd as-received (7.27% moisture)
Oxygen Purity:	100% oxygen at 1,025 psia and 275°F (135°C)
Hydrogen Purity:	100% hydrogen at 1,025 psia and 275°F (135°C)
Gasification Pressure:	1,000 psia
Gasification Temperature:	1607°F (875°C) hydrogasifier exit
Sulfur Removal:	Crystasulf process
Methanation:	Multistage methanation process with high conversion of both CO and CO ₂ to methane
Product Treating:	Drying and compression (to 875 psia)

The process has an overall thermal efficiency of 80% based on the higher heating values of the feeds and products. When the electrical energy that is required to produce the externally generated hydrogen and oxygen is considered, the overall thermal efficiency drops to 68% on a thermal HHV basis, but there are 33,200 kg/hr of pure oxygen available for other uses or sale.

Based on the Aspen modeling, external heat is required to maintain the thermal neutral operation of the hydrogasifier. As mentioned earlier, to get this additional heat, oxygen is introduced to burn a small portion of hydrogen in a H₂/O₂ pre-burner [9-11]. By this means, the hydrogen stream is heated to a high temperature before it contacts the coal to initiate the hydrogasification reaction. A manual trial and error procedure was used to calculate the oxygen feed rate going into the hydrogasifier. The oxygen feed rate was set to maintain the desired hydrogasifier exit temperature of 875°C (1607°F). The simulation result shows that a H₂/O₂ mole ratio of 30:1 is required in the pre-burner. This combustion generates about 5,600 kg/hr water vapor.

The pure oxygen flow rate to the ash combustor automatically was set so that there was 10% excess oxygen leaving the ash combustor. The excess hydrogen was removed from the SNG product and recycled back into hydrogasifier. Using the same simulation model, a series of sensitivity cases were also investigated to study the effect of reactor temperature, hydrogen/coal ratio, addition of CO₂ and H₂O et al.

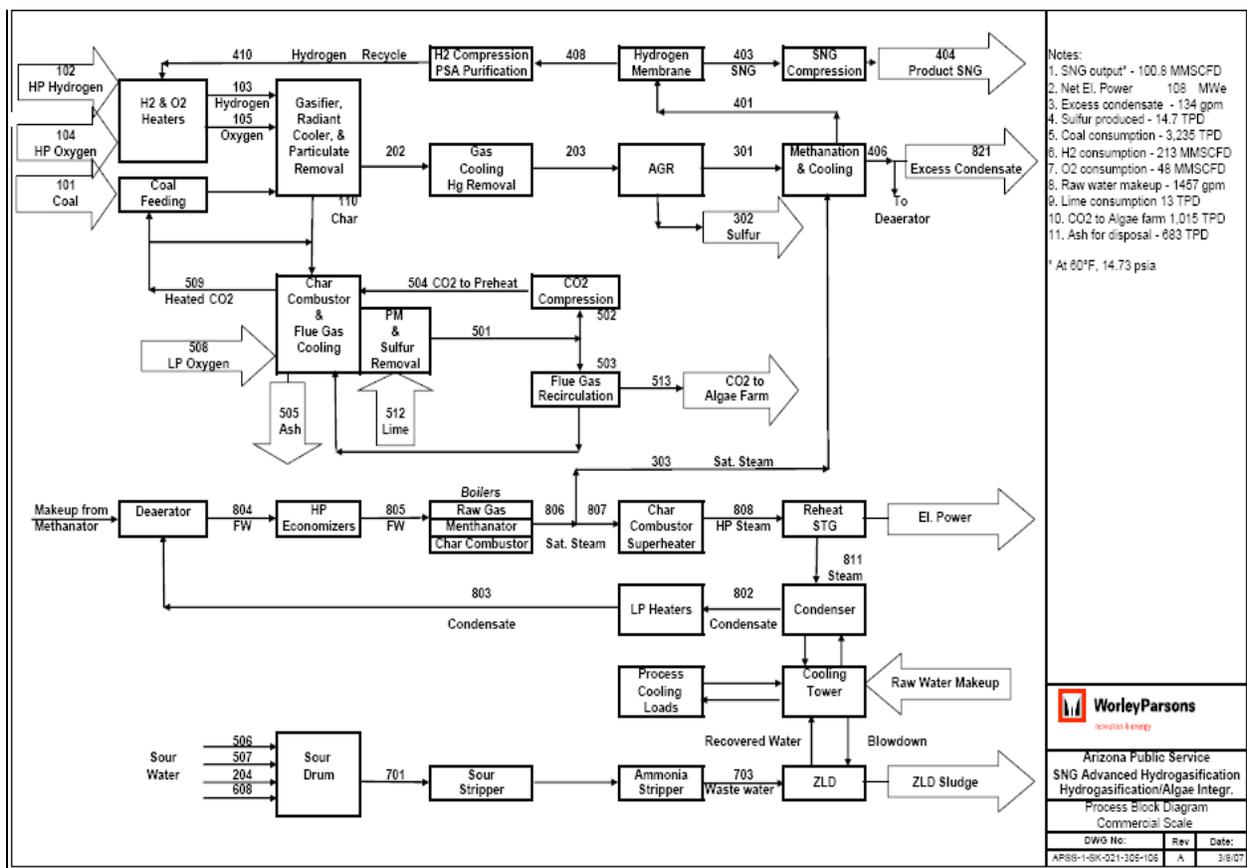


Figure VI-3 - Hydrogasification Processing Block Arrangement – CO₂ Fed into Algae Farm (also Figure I-1)

The CO₂ from the burner sent algae farm would consume up to 80% of the CO₂ and could ultimately use the algae to make renewable bio-fuels or other products. This has the advantage of reducing hydrogen use (and the accompanying cost avoidance) and actually producing marketable products. The disadvantage would be the tradeoff of adding an additional function with the accompanying land use and not capturing as large a percentage of carbon as the first option. However, for western utilities there are many advantages to this option that may offset the difficulties. The algae process offers a potential renewable credit (more on renewable below). Reducing hydrogen for the methanator may allow for other hydrogen adjustments in the process (to be explored further in Phase II). The algae addition would help offset some of the operational costs of the AHP process helping to control electric production costs. An AHP facility co-located with a conventional power plant could share an algae farm to also consume plant flue gas.

Figure VI-4 (similar to Figure VI-2) presents the algae integrated process, energy efficiency analysis

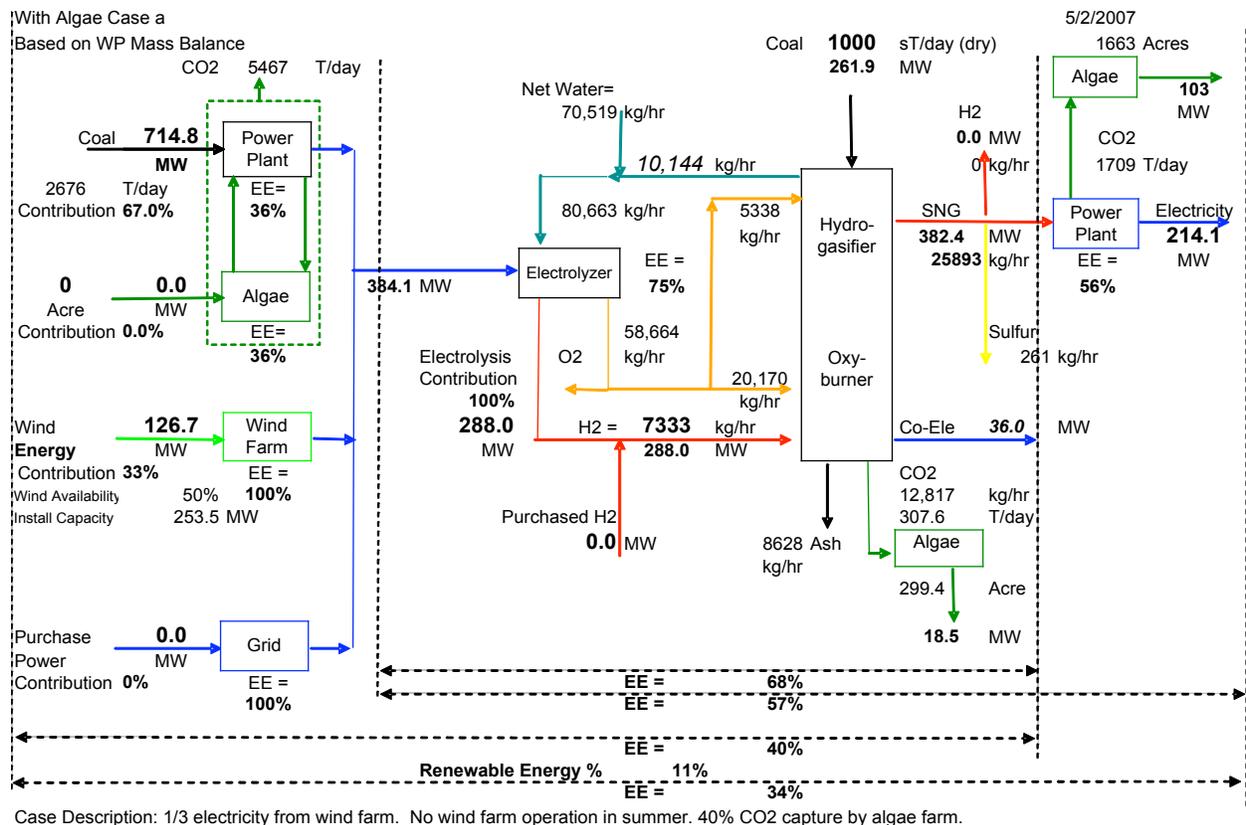
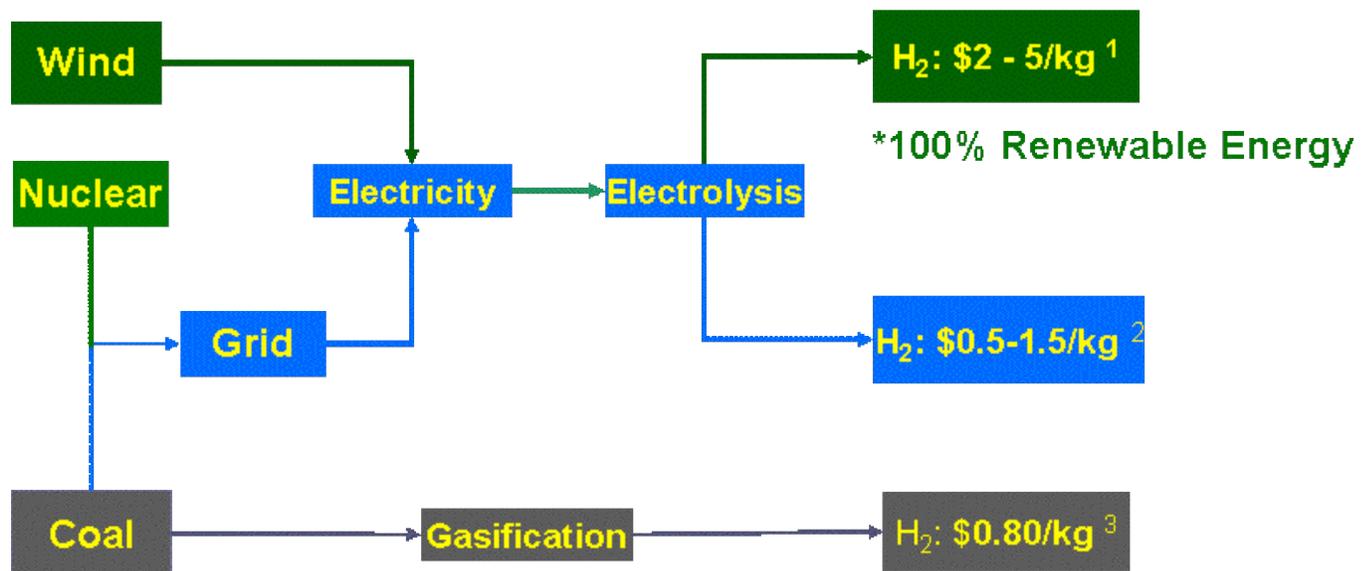


Figure VI-4: Energy Efficiency Analysis for Algae Integrated Process

SNG price was estimated for the algae integrated AHP process. The price is heavily dependent on the method of hydrogen supply. As shown in Figure VI-5, three main strategies are considered for hydrogen supply in the current APS AHP process. Path I was through electrolysis powered by wind electricity. This pathway provides 100% renewable hydrogen. However, due to relatively high cost of today's wind plant and electrolysis plant, the estimated hydrogen price is somewhere between \$2- 5/kg¹. Hydrogen storage needs to be included since wind electricity does not have a firm delivery. In Path II, the electricity required by electrolysis will be provided by APS internal off-peak grid electricity. It is likely that the hydrogen price will drop to between \$1 – 2 /kg. Path I and Path II can be combined since they all use an electrolysis process to produce hydrogen. Path III is to supply hydrogen through a gasification method. In this “Coal to Hydrogen” process, the coal is first gasified with oxygen and steam to produce synthesis gas consisting primarily of CO and H₂, with some CO₂, sulfur, particulates and trace elements. In “Hydrogen from Coal Program” report by US DOE [13, 14], three different further processes are described for hydrogen and electricity generation from this synthesis gas. The hydrogen price is claimed to be anywhere between \$0.4 – 1.1/kg.

Figure VI-5 Estimated SNG Price



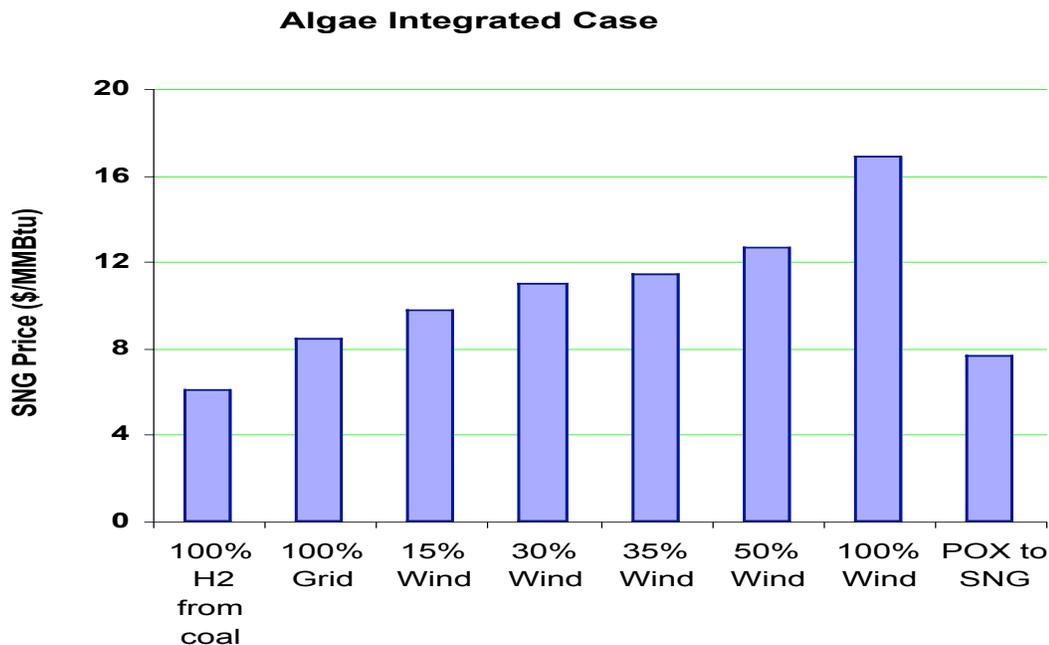


Figure VI-6 Hydrogen Impacts on Cost of SNG

Combining with estimated capital, O&M cost of hydrogasification process and electrolysis process, Figure VI-6 gives the estimated SNG price. Profits from co-generated electricity, biodiesel and cattle meals are also included in the calculation. As shown in the figure, the current estimated SNG price falls between \$4 - \$10/MMBtu. Using 100% wind electricity does not seem practical at the moment due to the scale of the project and the current availability/price of wind electricity.

For these two viable AHP renewable alternatives, which may be used separately or in conjunction to meet growing regulatory requirements for renewables, the Team has extensively evaluated the options for using wind-generated hydrogen as a part of the hydrogen feed into the AHP process. While this source of hydrogen would increase the cost of the methane produced it might be a viable consideration. When the AHP process begins commercial development, the value of renewable “developed” electricity in the west will be considerable. Electric power producers in States on the pacific coast or contiguous to them will have a very large market for renewable generated electricity either due to their own State’s mandates or the market in neighboring States. In consideration of the very large “renewable market” that will be in place by 2012, the team will continue to explore the economics and technical challenges of renewable power through AHP.

A review of the current two options demonstrate the potential of the AHP process to meet a significant portion of the nations electric power generators fuel needs –

- ◆ AHP provides fuel for the most advanced generation technology available today. Natural Gas fed Combined Cycle Generation Plants are efficient, easily sited, operated by small crews, environmentally friendly, and available from existing production facility with very short lead times.
- ◆ AHP offers power generators the option of production with a renewable component.
- ◆ AHP offers a “clean” alternative that can be enhanced with CO₂ removal at the CC plant that the AHP methane is delivered to.
- ◆ AHP offers additional renewable credit through algae, and the added advantage of cost reduction through additional product creation.
- ◆ AHP provides higher efficiency in the process from the beginning to the end
- ◆ AHP can be located at coalmines while delivering through existing pipeline infrastructure to load centers.
- ◆ AHP will stabilize pricing for Combined Cycle plant fuel
- ◆ AHP offers a sustainable technology with hundreds of years of potential production.
- ◆ AHP offers a future, rather than compromises

While the considerable accomplishments in Phase I have provided a fully delineated process with critical flexibility, a great deal of work remains in Phase II to fully understand the advantages and challenges of the options. And in Phase II it is anticipated that further options will evolve and be added to the process flexibility. It might seem counter productive to offer and continue to explore alternatives. But in the current circumstances for US electric utilities, flexibility appears to be very much required.

During eras of major transition it is difficult to anticipate the specific technologies that will respond to the need. Those options that offer sustainability, technical flexibility and do the least harm generally emerge as successful answers. The Team is striving to build in alternatives to meet the need and the varieties of circumstances that challenge electric utilities.

3. Coal Tests

The project analyzed Fruitland coal from field in the Northwest New Mexico. Table VI-2 summarizes the coal physical and chemical characterization. This western coal has relatively low moisture and high ash content. On a dry basis, it has a heating value of 10,710 Btu/lb.

Coal High Pressure TGA (HPTGA) Test

Three HPTGA tests have been successfully completed by Gas Technology Institute, Chicago, IL, to evaluate the gasification reactivity of the devolatilized Fruitland coal sample in the 1500-1700°F temperature range, at 500 psi pressure using a 50 vol% H₂O – 50% N₂ gas mixture. One additional test was also carried out at 1700°F, but at the higher pressure of 700 psig. HPTGA test results indicate the devolatilized Fruitland coal sample is highly reactive under these regular gasification conditions. Consistent with expectations, reactivity improved with increasing temperature. Reactivity was reduced at the increased pressure. It took 90 minutes to achieve ~100% base carbon conversion at 1500°F (and 500 psig). Similar high conversions were achieved during 30 minutes at 1600°F and during only 15 minutes at 1700°F. At 1700°F, reactivity at 700 psi was lower than that at 500 psig, requiring about 25 minutes to achieve complete conversion compared to 15 minutes at the lower pressure.

Table VI-2 Properties of Fruitland Coal

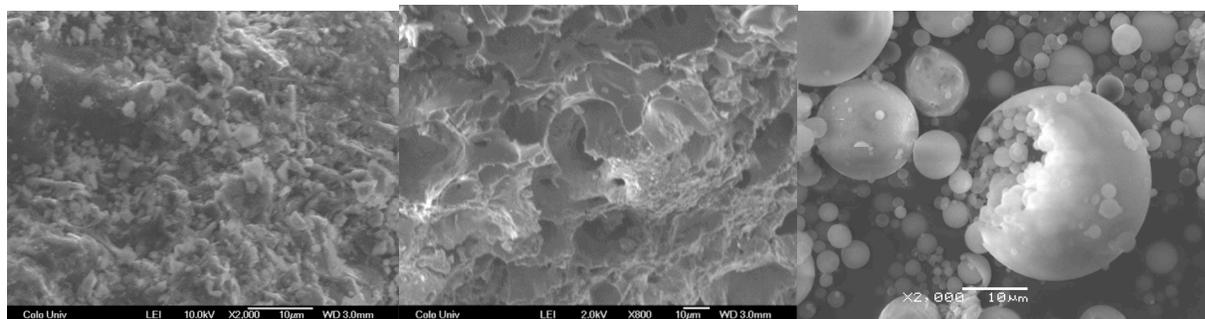
Proximate Analysis	As Received	Dry Basis	
Moisture, %	7.27	---	
Volatile Matter, %	35.00	37.74	
Ash (950°C), %	20.07	21.32	
Fixed Carbon, % (by difference)	37.66	40.94	
Ultimate Analysis	Dry Basis	Fluorine, Chlorine, and Trace Elements (μg/g)	
Ash (750°C), %	21.32	Fluorine	87
Carbon, %	61.92	Chlorine	99
Hydrogen, %	4.61	Arsenic	< 200
Nitrogen, %	1.28	Cadmium	< 6
Sulfur, %	0.69	Lead	< 200
Oxygen, % (by difference)	10.18	Mercury	0.055

The hydrogasification performance of Fruitland coal was tested using the same technology. A raw coal sample (100 milligrams, -20+50 mesh) was used for this test. The testing conditions were 1600°F, 800 psig, and 90% H₂-10% N₂ mixture. With a heating rate of 1000°C/min, the coal sample reached the desired test temperature within a few seconds. The test took 96 minutes until no further weight change was measured. Base carbon conversion was estimated as 84.8%. This lower conversion suggests that the

coal is not as reactive under hydrogasification conditions as regular gasification conditions. The process may tend to be a kinetic controlled process. Even lower conversion should be expected during the bench/engineer scale operation because of the limitation on the achievable residence time.

Figure VI-7 shows Scanning Electron Microscopy (SEM) images of fresh coal, char from HPTGA test and fly ash from power plant. SEM confirmed cavity structure in the char sample, which indicates, entrapped volatiles burst during the testing. Fly ash is essentially fine particles (<10 μ m). Energy Dispersive Spectroscopy (EDS) indicates that fly ash is mainly composed of aluminum, instead, both the fresh coal and char samples are mainly composed of carbon and oxygen, with trace amounts of aluminum.

Figure VI-7 SEM of Fresh Coal, Char Sample from HPTGA, and Fry Ash from Power Plant



4. Bench Scale Testing

The proposed AHP process combines off-the-shelf technology with the advanced technologies in the hydrogasifier and Algae farm. APS is building a bench-scale hydrogasifier. The objective for bench-scale testing is to experimentally verify key assumptions for the APS AHP process and develop the kinetics of western coal hydrogasification step. The knowledge will be used to optimize operating conditions, develop kinetics of Fruitland coal hydrogasification reaction, update ASPEN process modeling, support commercial scale hydrogasification reactor CFD modeling and guide the next phase experimental testing.

To be specific, the objectives are as follows.

- To determine the effect of hydrogen/carbon ratio, residence time, temperatures, and pressures on the methane production rate and conversion efficiency from hydrogasification using Fruitland formation coal.
- To determine the effect of steam and CO₂ on the methane production rate and conversion efficiency from hydrogasification using Fruitland formation coal.
- To characterize and quantify major gas by-products.

- To characterize and quantify tar and light oil products (BTX).
- To determine the compositions of char. Balance C and S mass flow.

The bench-scale test reactor must be capable of varying these variables to determine optimum conditions for methane production. The current bench reactor design is 1.6" i.d. and 12 feet long (reaction zone). It can provide a test range of 5 - 15 lb/hr coal feed rate, 300 -900 SCFT hydrogen feed rate, and up to 1900°F temperature and 1200 psig pressure. The system also has the capability to test the effect of H₂O and CO₂ additions. Key Test Parameters are as follows:

1. Test temperatures may vary from 1,200 to 1,800°F. The upper limit must envelop the calculated optimum temperature of 1,600°F, currently used as a base value to model process conditions.
2. As reaction rates are dynamic in nature, a continuous bench-scale test process is required. The process will be capable of sustaining stable operation for a period sufficient to make real time measurements of product gas data, or to take product gas samples for off line analysis.
3. The bench-scale test reactor will be capable of varying gas constituents in the reactor environment, including hydrogen, steam, CO₂ and nitrogen.
4. The bench-scale test reactor will be capable of varying the hydrogen and coal feed rate to achieve varying residence times.
5. The bench-scale test reactor will be capable of continuously feeding 200 mesh coal for the period determined by Key Parameter 2. The reactor should be capable of feeding micronized coal, if faster reaction rates are required.
6. The bench-scale reactor will provide for measuring reactor internal temperature at various points along the reaction path.
7. The bench-scale reactor will incorporate sufficient automatic controls to allow safe and stable operation.
8. The bench-scale test facility will provide for the collection and analysis of bottom ash, fly ash, condensable products and product gases.
9. The bench-scale test facility will be equipped with emergency shutdown and inerting systems, which automatically actuate if the reactor exceeds pre-determined conditions, such as - coal agglomeration happens within reactor, for safe operation
10. The bench-scale test facility has been designed to meet applicable ASME codes and its operation shall comply with all applicable environmental, health and safety regulations.
11. Bench-scale reactor operation, data collection and data analysis will be controlled by procedures within a quality assurance program.

Bench Scale Reactor Design

A Bench scale test plan and design for the test reactor were completed in Phase one. Fabrication of the Bench Scale Test reactor is underway.

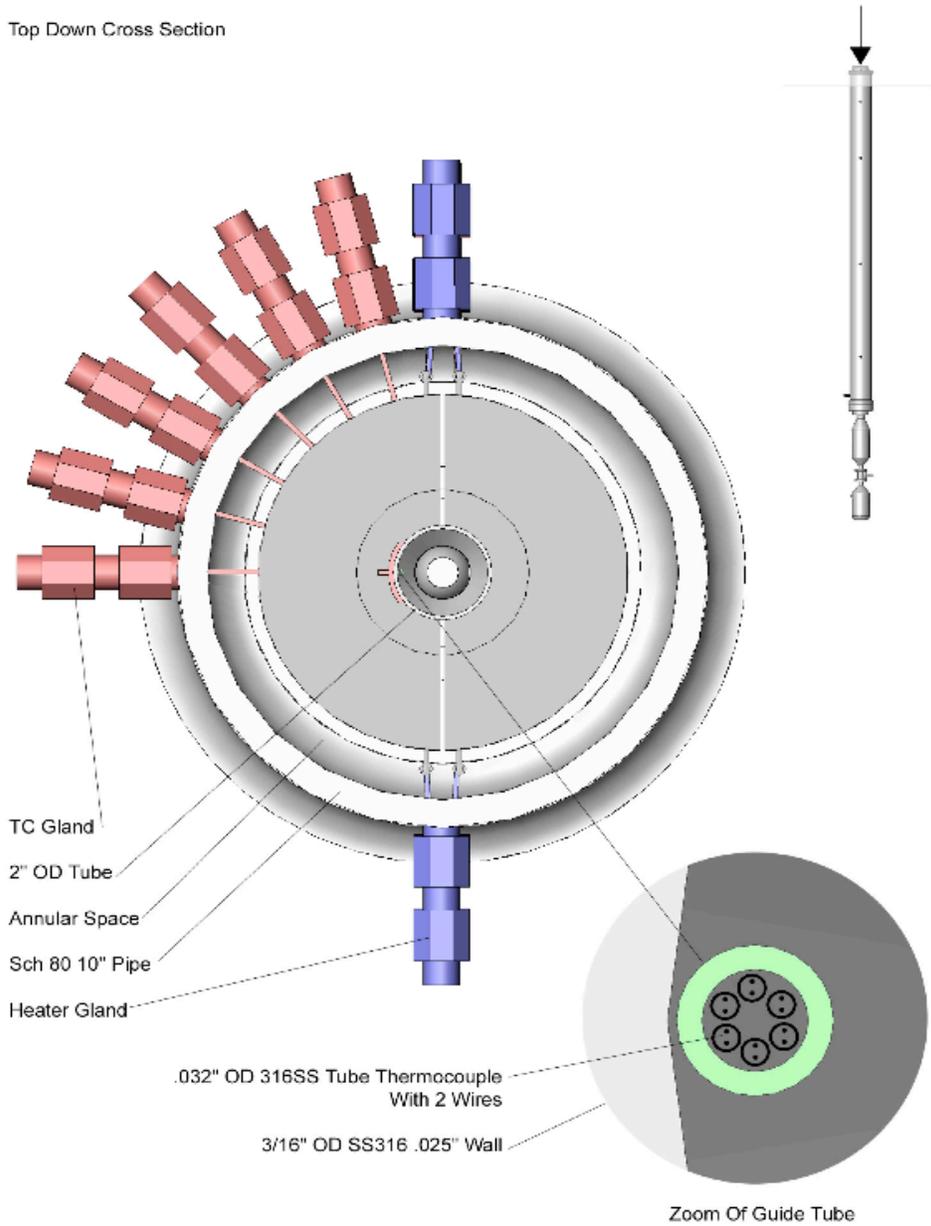


Figure VI-8 Test Reactor Views

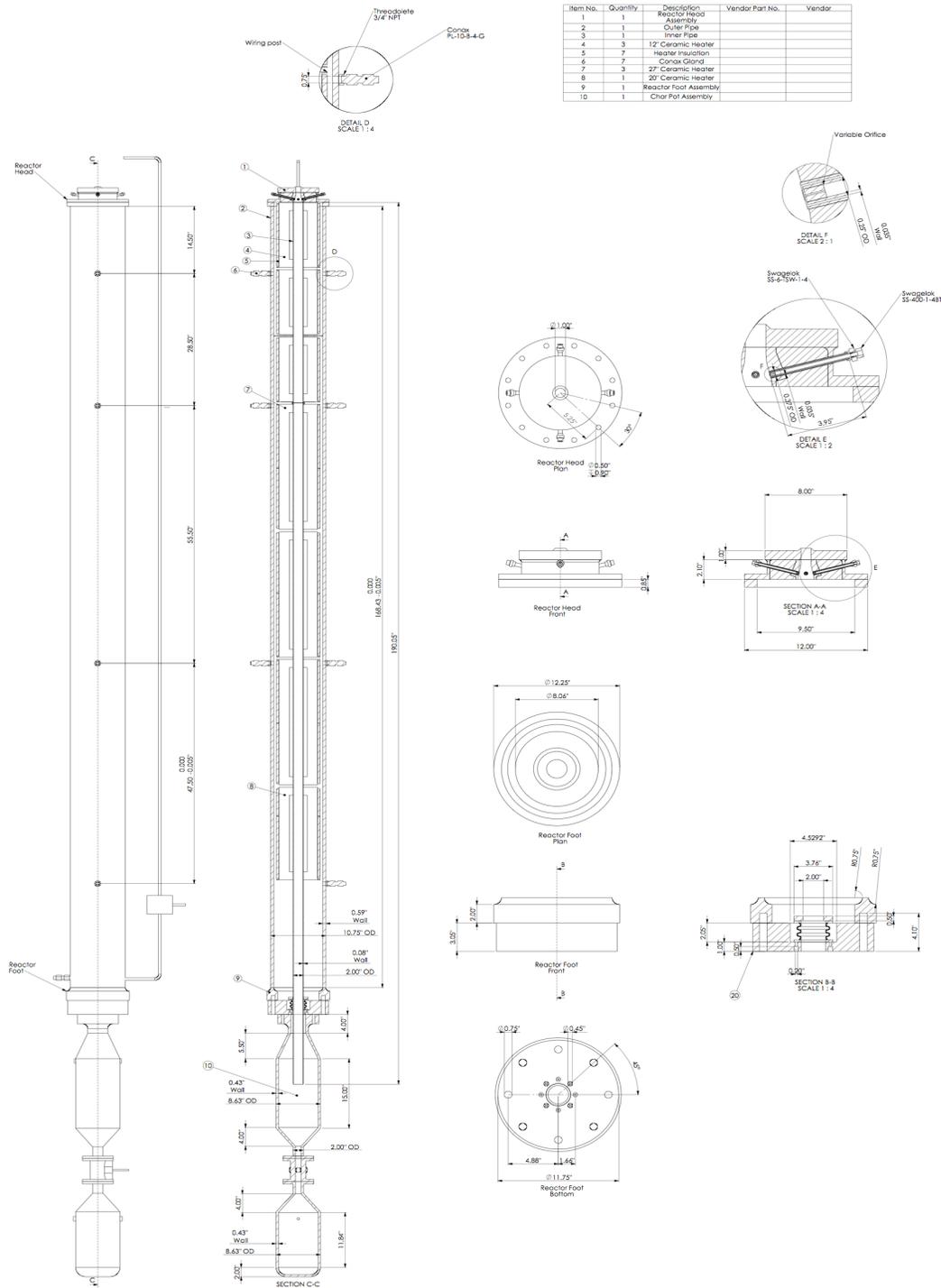


Figure VI-9 Test Reactor Dimensions

Bench Scale Test PI&D

Figure VI-X gives the full flow sheet for bench scale testing. For simplicity, the H₂/O₂ tip-burner design is not introduced into this bench reactor. Instead, H₂ and the whole reactor are heated by external furnaces. Dual char hoppers and condensers are designed to separately collect char and oils produced at transit and steady states. Water cooling jackets are designed for coal hopper, reactor head, tube entrance to char hopper, and condenser. The system is fully automated. All the analytical instruments and control panels locate in the control room.

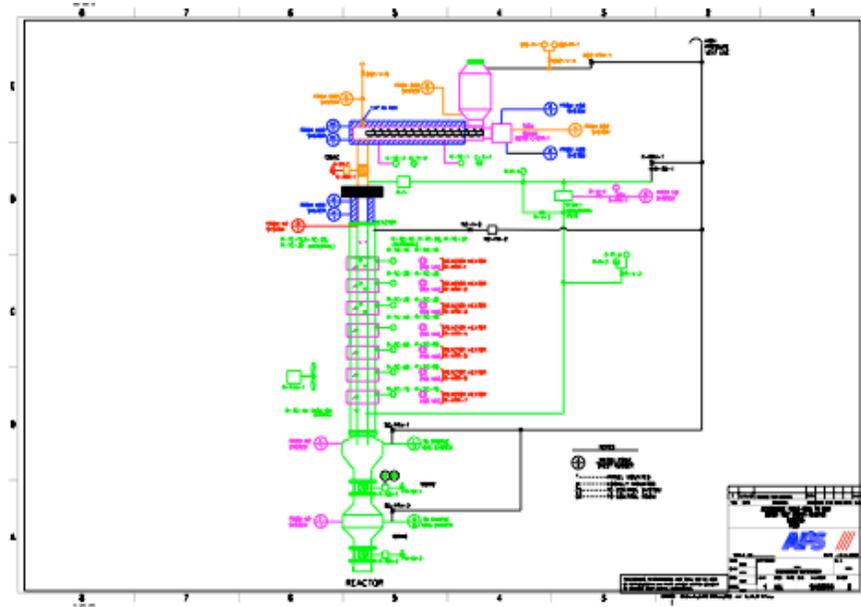


Figure VI-10 Bench Scale Test PID

Bench Scale Test Plan

Table VI-3 and VI-4 give proposed testing plans for bench scale testing. Functionally testing as well as calibration of the magnetic coal feeder are the main tasks during the pretesting period. The mixing of fused silica to coal is required once coal clogging is observed. Dried pulverized (200 mesh) coal will be used. During the pretesting, hydrogen will be tested as a candidate of carrier gas. If successful, a base line will be created to study the effect of CO₂ and H₂O to this coal hydrogasification process. Safety will be a main issue to investigate when hydrogen is used as carrier gas.

Table VI – 3 Pretesting Plan**Pretesting****Cold Reactor Test - Functionality Test**

	Run #	T (°F)	P (psi)	Coal FR(lb/hr)	Inert Gas	Carrier Gas
Pressure Test	1	Ambient	1000	0	N2	
	2	Ambient	1000	5		N2
	3	Ambient	1000	10		N2
Coal Feeder Test	4	Ambient	1000	15		N2

Adjust fumed silica addition up to 10 wt% ensure coal flow.

Hot Reactor Test/Coal Feed Calibration

	Run#	T (°F)	P (psi)	Coal FR(lb/hr)	Inert Gas	Carrier Gas
Pressure Test	5	1600	1000	0	N2	
Functionality Test	6	1600	1000	5		N2
	7	1600	1000	10		N2
	8	1600	1000	15		N2
Coal Feeder Calibration	9	1600	1000	5		H2
	10	1600	1000	10		H2
	11	1600	1000	15		H2

Calibrate coal feeder at HT, HP condition.

* Information to Be Learned during Pretesting:

1. System can provide required temperature and pressure environmental.
2. **Coal feeder calibration curve.**
3. Carrier gas will provide a safe and reliable coal flow.

Using JMP, 16 main tests were designed with temperature, H₂/coal mass ratio and coal feed rate as design factors. The following are the minimal requirements for testing data collection.

1. The quantity and rate of coal feed.
2. The quantity of bottom char and fly ash produced.
3. The quantity and rate of hydrogen, CO₂ and steam feeds to the bench-scale reactor.
4. Temperatures of all gas and solid feeds, a temperature profile along the reaction path, temperatures of product gas outlet, char receiver, condenser and sampling stream.
5. Pressures of all reactor feed streams, coal hopper, char receiver, reactor internals condenser, and sampling stream.
6. Complete chemical analysis of product gas and condensable products produced by the bench-scale reactor. Need to measure: CO, CO₂, H₂, H₂O, H₂S, COS, R-SH (mercaptans), olefins, and paraffins C²⁺ material including BTX (benzene, toluene, xylene), long-chain tar and oil, HCl, and phenolic species.
7. Characterize char C, H, O, N, S, and Ash.
8. Power and energy required to maintain reactor temperature.

Table VI-4 Testing Plan

	Temp(°C)	H ₂ /Coal Mass Ratio	Coal FR (lb/hr)
1	1550	0.2	5
2	1550	0.2	15
3	1550	0.3	10
4	1550	0.4	5
5	1550	0.4	10
6	1550	0.4	15
7	1650	0.2	10
8	1650	0.3	15
9	1650	0.4	5
10	1650	0.4	15
11	1750	0.2	5
12	1750	0.2	15

13	1750	0.3	5
14	1750	0.4	5
15	1750	0.4	10
16	1750	0.4	15

5. Performance of Carbon Capture - Algae Farm

Working with GreenFuel Technologies (GFT), a pilot algae system (GEN3) was built at the APS Red Hawk NGCC power plant. Actual results from the Red Hawk GEN3 system demonstrated an algae growth rate of 57 grams per square meter-day. This growth rate extrapolated to 150 tons/acre-year of carbon capture, which could yield about 11,000 gallons of biofuel annually per acre. Economic modeling estimates the cost of algae-based transportation fuel from this process to be competitive with petroleum based fuels, when systems are built to moderate scale. In addition, the adsorption of carbon dioxide is 70 times the rate per unit of land compared to conventional agricultural operations. The corresponding growth rates result in yields that produce 20-70 times more biofuel than other conventional Table VI-5 Diagram Biomass Performance crops including corn, canola, and jatropha trees, without using limited resources as fresh water and fertile land.

Table VI-5 Diagram Biomass Performance [15]

Crop	CO ₂ Capture (tons/acre/yr)	Biodiesel Yield (gals/acre/yr)	Ethanol Yield (gals/acre/yr)
GFT Algae process	150	8,000	3,000
Corn	<6	18	328
Soybean	<2	48	n/a
Canola	<2	127	n/a
Jatropha	-	194	n/a

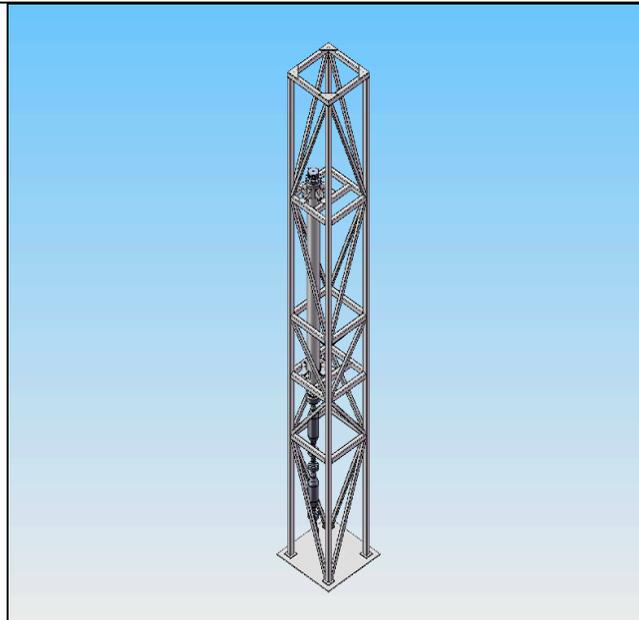
An Engineering Scale GEN5 System has been constructed at APS Red Hawk Combined Cycle plant and will undergo performance testing during Phase II. The GEN5 system is expected to capture higher amounts of CO₂ per acre at lower costs and at higher efficiency than the GEN3 system. Higher capture rates will result in greater amounts of algae per acre.

6. Summation

One of the key challenges in the coming decade is to produce electricity in a more sustainable manner without the production of large quantities of carbon dioxide emissions. This project is aimed at achieving this goal by developing and demonstrating an engineering- scale coal hydrogasification-based process using western coal and renewable hydrogen source. Sustainable SNG will be supplied and complete carbon recycle will be accomplished using an algae farm.

The proposed APS AHP process combines a hydrogasification reactor to produce methane tied to generating unit to burn excess char from the gasification (co-production of electricity) and a back end clean up utilizing algae to reformat the CO₂. The algae process essentially allows for the recycling of carbon back into the process, which makes the designed hydrogasification process is “zero emission”. The Algae produced could also be feedstock to produce Biodiesel and cattle meal. There are multiple variables in utilizing renewable sources for hydrogen production and for applying algae to capture CO₂ from the SNG process or electric generation facilities. The AHP process will have an overall energy efficiency above 78%. An Algae farm with a GEN3 system can capture 150 tons/acre-year of carbon dioxide and can yield about 11,000 gallons of biofuels (biodiesel and ethanol) per acre year.

VI-11 Representational Drawing of the Bench Scale Test Reactor



“I KNOW OF VERY FEW (AMERICANS) WHO ARE DREAMING OF A WORLD FOR THEIR GRANDCHILDREN.”
KURT VONNEGUT

“I THINK THERE IS A WORLD MARKET FOR MAYBE FIVE COMPUTERS.”
THOMAS WATSON, PRESIDENT OF IBM, 1943

VII. Hydrogasification/SNG System Plant

1. Major Component Description

The overall process and the hydrogasifier were described in previous sections. This section presents the description of the major components other than the hydrogasifier. A brief description of major systems and the associated component/ system sizing is presented in the following table.

Table VII-1 - Hydrogasification / SNG Process Configuration and Design Redundancy

System	Description	Quantity/Capacity
Gasifier	APS Hydrogasification Reactor	3 x 33%
Fuel Feed (per Gasifier)	Dry feed (Stamet Posimetric pump)	9 x 16.7% [i.e. 3 x 50%, per Gasifier]
Coal Preparation (per Plant)	Pulverized Coal Mills (70% through 200 mesh.)	3 x 50%
Syngas Scrubbing	Tray counter flow	1 x 100%
Hydrogen / Oxygen Generator	Electrolysis Unit (not in cost basis)	NA
Char Combustor	Oxygen blown CFB	1 x 100%
CO ₂ Recycle System	CO ₂ cooling/reheat/compression	1 x 100%
Mercury Removal	Sulfur impregnated carbon bed	1 x 100%
Acid Gas Removal	CrystaSulf, physical solvent	1 x 100%
Sulfur Recovery	Via CrystaSulf Process	1 x 100%
Methanation unit	Catalytic	1 x 100%
SNG Cleanup System	Membrane/PSA	1 x 100%
Flare System	Free standing elevated flare	1 x 100%

A more detailed description of the major components/ systems is presented below. Additional details and Process Flow Diagrams can be found in the Preliminary Engineering Package.

Coal Receiving and Storage

New coal receiving, storage and reclaim systems will be sized for nominal 3300 tpd of Fruitland sub bituminous coal. The coal will be delivered to the site by 200 tons/load trucks from BHP Navajo Coal Company mine, located about one mile from the plant. Trucks dumping the coal into two receiving hoppers, equipped with grizzlies, will do the unloading. Coal is withdrawn from each hopper by a single belt feeder. The 3" x 0 coal is discharged from the belt feeder onto a belt conveyor that includes a belt scale and “as-received” sample system. The coal is then conveyed to the storage pile. A linear traveling stacker that builds a 7 day storage pile forms the pile.

Coal Preparation System

Coal is delivered to the coal preparation system silos from the coal storage system via a reclaim system. The coal is reclaimed from the pile by rotary plows in a concrete tunnel under the pile. A reclaim conveyor delivers reclaimed coal from the storage pile. The reclaim conveyor includes a belt scale, magnetic separator and an “as-fired” sample system. The reclaim conveyor deposits the coal into a surge bin in the crusher building. A belt feeder withdraws coal from the surge bin and conveys it to the crusher where it is reduced to 1”x 0. From the crusher, the coal is deposited onto a conveyor that lifts the coal to the top of the two (2) coal storage bins. A series of diverter gates and conveyors distribute the coal to the desired storage bin. From the crushed coal silos, coal is fed into coal pulverizers. The coal is pulverized in three mills (3 x 50%) to the fineness of 70% passing through a 200 mesh sieve¹. Pulverized coal is carried by the inert gas to pulverized coal silos (two silos per each gasifier, total of six silos per plant). Coal particles are separated from the inert gas in sleeve filters. Milled coal is stored in silos at atmospheric pressure with inert gas blanket.

Coal Feed System

The coal feed system for each hydrogasifier is comprised of 3 trains, each sized for 50% of coal feed requirement per gasifier unit, or 16.7% of total hydrogasification plant coal feed rate of 3,300 tpd. The coal is drawn from the pulverized coal silo and fed by Stamet posimetric solids pump to a pneumatic conveyor. Coal is pressurized and fluidized with carbon dioxide gas, and transported to horizontally-opposed feed injectors on the hydrogasification reactor.

H₂ Production and Handling

Although the Electrolysis will provide the bulk of the H₂, some will be provided by a hydrogen membrane and PSA system. The Electrolysis unit is “over-the-fence” from the hydrogasification/ SNG process.

Raw Gas Cooling and Entrained Particulate Removal

The crude raw gas leaving the hydrogasifier at approximately 1600°F contains a small quantity of char. This gas stream would be cooled in radiant boilers for heat recovery via high-pressure saturated steam generation. The entrained ash will be separated prior to particulate removal. The gasifier in this study uses a radiant cooler. The hot raw dust-laden gas from the hydrogasifier is cooled in a radiant heat exchanger, which recovers the heat of the syngas for steam generation. The partially cooled gases pass through a cyclone and a candle filter with the collected solids drained to the collecting hopper. The

¹ ASTM 200 mesh sieve has nominal aperture of 74 microns.

cleaned gas is then piped to the Acid Gas Removal system via several heat exchangers that further recover heat from the gas for the feed water heating. Ash is removed from the cyclone and candle filter drains to a collecting hopper from which it passes into the lock hopper pressure letdown system. The char is then fed to the oxygen blown char-burning CFB.

Mercury Removal

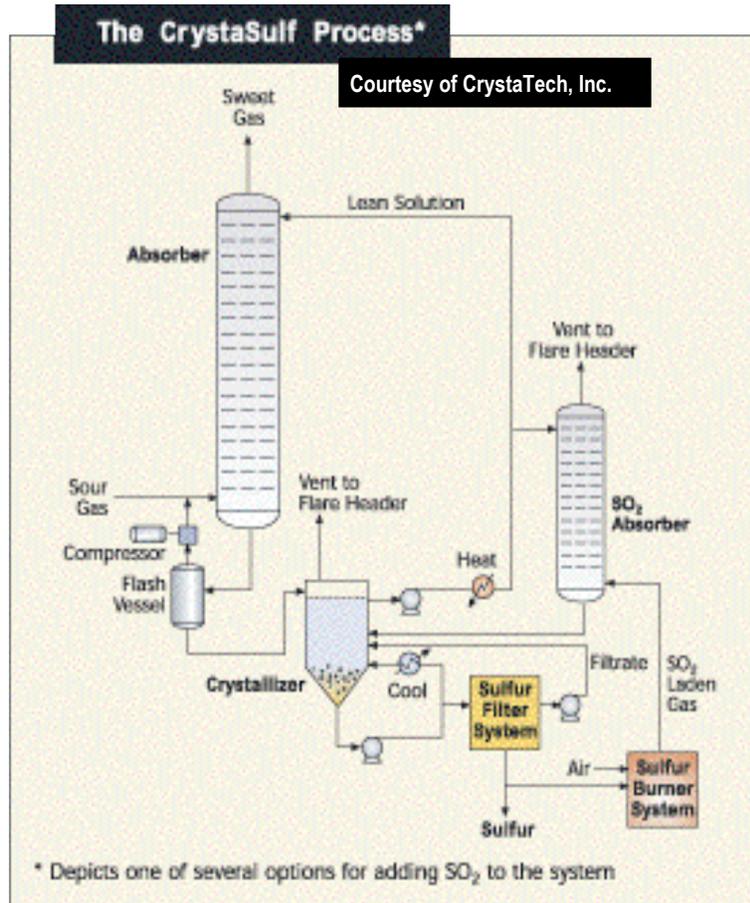
A packed bed of sulfur-impregnated activated carbon accomplishes mercury removal. A bed of sulfur-impregnated activated carbon with approximately a 20-second superficial gas residence time would achieve more than 90 percent reduction of mercury in addition to removal of some portions of other volatile heavy metals such as arsenic. The packed carbon bed vessel is located upstream of the AGR unit and at a temperature near 100°F. For this study, a 24 month carbon replacement cycle was assumed. Under these assumptions, the mercury loading in the bed would build up to almost 3.6 wt%. Mercury capacity of sulfur-impregnated carbon can be as high as 20wt%^[16]. The mercury laden carbon is considered to be a hazardous waste, and the disposal cost estimate reflects this categorization.

Acid Gas Removal and Sulfur Recovery

CrystaSulf process is selected for the Acid Gas Removal (AGR) unit and sulfur recovery. The low sulfur Fruitland coal and the hydrogasifier reactions produce a syngas containing ~2000 ppmv of sulfur compounds, which corresponds to a relatively small amount of sulfur (~20 TPD) to be recovered in the process. CrystaSulf is reported to have an economic advantage over the physical or chemical solvent AGR combined with a Claus Sulfur Recovery Unit (SRU) for sulfur recovery rates of 20 to 30 TPD ^[17].

CrystaSulf is an aqueous sulfur recovery process that removes hydrogen sulfide and SO₂ from gas streams and converts it into sulfur. The CrystaSulf process utilizes a proprietary non-aqueous solution and operating conditions that promote liquid-phase conversion of H₂S and SO₂ to elemental sulfur.

H₂S is removed from the sour syngas in a countercurrent tray absorber, where H₂S reacts with dissolved sulfur dioxide in the circulating CrystaSulf scrubbing solution according to the Claus liquid process reaction to produce dissolved elemental sulfur. The CrystaSulf solution has a high solubility for sulfur, which remains totally dissolved at the process operating temperature. The sweet syngas from the absorber, with sulfur compounds volumetric concentration in low single digits of parts per million exits the system. A typical CrystaSulf process is illustrated Figure VII-1.

Exhibit Figure VII-1 Typical CrystaSulf Process

Char Combustor

The solids leaving the gasifier are combusted with an O₂ stream in order to generate a nearly pure CO₂ stream. This is accomplished in an oxygen blown circulating fluidized bed boiler (CFB). The oxygen blown CFB steam generator system described herein is based on results obtained by the Alstom Power Inc. during their Phase 2 pilot scale testing of an oxygen blown CFB [18]. The thermal and chemical energy in the char supplies the energy needed to raise 1800 psig/1000°F/1000°F steam for the steam turbine. Approximately 70 percent of carbon in the coal is converted in the hydrogasification reactor. The remaining 30 percent exit the gasifier vessel as a char, and primarily consist of ash and carbon with small amounts of hydrogen, nitrogen, and sulfur, and is cooled in a stripper/ cooler and depressurized. The residual carbon-rich char from the gasifier is cooled in a stripper/ cooler, depressurized, pelletized to particle size of approximately 0.25-inch and stored in a containment vessel before being injected into the CFB boiler for final combustion.

The average size of char particles coming out of the gasifier is expected to be ~50 microns or less. The CFB process requires feedstock size of approximately 0.25-inch. Agglomeration of the char to a nominal size of 0.125 to 0.25 of an inch will be accomplished in a pelletizer.

In the boiler, residual carbon-rich char is reacted with a preheated mixture of oxygen and recirculated flue gas in the Combustor section of the Circulating Fluidized Bed (CFB) system. The oxygen supply is provided over the fence from an Electrolysis Unit. The products of combustion (comprised of primarily CO₂ and H₂O vapor and un-reacted hot solids) leave the combustor, and flow through a cyclone, where most of the hot solids are removed. The hot solids are recirculated to the combustor. Draining hot solids through a water-cooled fluidized bed ash coolers controls solids inventory in the system, while recovering heat from the hot ash. The flue gas leaving the cyclone is cooled in an economizer located in the convection pass of the system. The flue gas leaving the convection pass heat exchanger sections is further cooled in an oxygen heater. The oxygen stream from the Electrolysis Unit is mixed with a small stream of recirculated flue gas and the mixture is preheated in the Oxygen Heater. The flue gas leaving the oxygen heater is cleaned of fine particulate matter in the Particulate Removal system. Flue gas stream leaving the Char Combustor consists primarily of CO₂ with some water vapor. Water is subsequently condensed out of the CO₂ stream in cooling, knockout and compression steps, and prior to CO₂ stream being recycled to Hydrogenation system.

Ash/Waste Handling System

The oxygen-blown CFB Char Combustor operates at non-slugging conditions. Therefore, both the solids produced from the bottom of the char combustor as well as those entrained with the flue gas are classified as “ash” products. The bottom ash and fly ash are cooled and depressurized via separate pathways. Both ash streams are combined and transferred to the ash silo. The ash silo is sized for a nominal holdup capacity of 72 hours of full-load operation. At periodic intervals, ash-hauling trucks will transit the unloading station underneath the silo and remove a quantity of ash for disposal.

The fly ash collected in the bag-house is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is sluiced to hydro-bins for

dewatering and offsite removal by truck. Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) is conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced on a periodic basis to the hydro-bins.

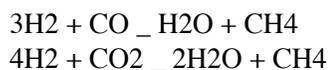
Hydrogenation, and CO₂ Compression and Handling

CO₂ from the Char Combustor System's Knock out drum is compressed in a Multistage Intercooled CO₂ compressor to around 1000 psig before it is sent to the Hydrogenation system. In the Hydrogenation system, excess oxygen is removed by reaction with hydrogen before the CO₂ is recycled to the gasifier or sent to the CrystaSulf system. The Hydrogenation feed is preheated above 400°F using reactor product or a start-up heater before it is sent to the first stage of the reactor. Following the first stage of the reactor, a high pressure steam generator cools the products. Following the first stage cooling, the reactor products are further reacted with hydrogen in a second stage reactor. The hydrogenation reactors operate at approximately 750°F and 980 psi. Products from the second stage are cooled using a cooling train including high pressure steam generation, feed preheat, HP Boiler feed water, and condensate. Following the cooling train at approximately 160°F, condensed water is removed in the CO₂ knock out drum before it is sent to the sour water stripper. CO₂ from the Knock Out Drum is split into two streams; one proceeds to the gasifier cooling train where it is further cooled and the remaining sulfur is removed in the CrystaSulf Unit. The remainder of the CO₂ is compressed above 1040 psig in the Transport CO₂ Compressor before it is sent to the lock hoppers and the gasifier coal feed system.

Methanation Unit

Desulfurized vapor from the CrystaSulf System is preheated in the Feed/ Product Exchanger and a Start-up heater to about 500°F before it enters the Zinc Oxide (ZnO) guard bed to remove any remaining sulfur which would poison the Methanation reactor catalyst. Steam is added to the reactor feed to maintain 40 volume % steam in the Methanator feed. The steam addition is necessary in order to limit soot formation through the Boudouard-type carbon reactions. From the guard bed, the reactor feed proceeds to the Methanation reactor where Hydrogen reacts with Carbon Monoxide and Carbon Dioxide to produce Methane and water. The reactor itself is a tubular fixed-bed catalytic reactor with steam generation to remove the heat of reaction. The exhaust temperature from the Primary Methanation Reactor is 650°F.

The Methanation reactions are as follows:



From the Methanation Reactor, the product is cooled through a cooling train including Methanator Feed, Low Pressure Steam Generation, Steam Condensate, condensate from the Methanator Flash Drum and finally Cooling Water. Following the cooling system, the condensed water is separated and flashed at close to atmospheric pressure. The overheads from the low pressure flash are sent to the Char Combustor while the clean condensate is sent to the Deaerator for use in the steam cycle. The product vapor from the high pressure Methanator K.O. Drum at 110°F is dried in a TEG (Triethylene Glycol) Unit. Water from the TEG Unit is vented. The dried SNG is sent to a membrane purification system, which has two products; a low pressure (65 psia) Hydrogen rich stream and a high pressure (about 800 psia) SNG stream. The SNG product is compressed above 910 psia before it is exported as a SNG product. The low pressure hydrogen stream contains roughly 90% Hydrogen which is compressed to over 1000 psia before it is purified in a pressure swing adsorption (PSA) system. This system produces a high pressure pure (99.9+%) hydrogen product, which is recycled to the Hydrogasification reactor. The low pressure rejects from the PSA unit are sent to the Char Combustor for incineration.

Steam Turbine

The steam turbine is a tandem compound type, consisting of an HP-IP and two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with unregulated extractions and four-flow exhaust.

Steam System

The function of the main steam system is to convey main steam from the Char Combustor super heater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the Char Combustor reheater, and to the turbine reheat stop valves. Main steam system will be operating at 1800 psig/1000°F, and reheat system will be operating at 1000°F.

Feedwater System

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank to the CFB (char burner) steam drums. Two 100 percent capacity boiler feed pumps are provided.

Circulating Water System

The circulating water system supplies cooling water to the condenser to condense the main turbine exhaust steam. The system also supplies cooling water to the auxiliary cooling system. The heat transferred from the steam to the circulating water in the condenser is removed by a mechanical draft cooling tower.

Cooling Tower

A mechanical draft, fiberglass structure, counter-flow cooling tower is provided for the circulating water heat sink. The cooling tower is comprised of a linear array of 9 cells, each containing a 200 hp fan that induces airflow through the tower fill. Hot circulating water from the condenser is sprayed on to the spray deck above the fill, and falls down in films over the fill with a counterflow of air rising and cooling the water. Approximately 80% of the heat transfer occurs by evaporation of the water, with the remaining 20% occurring by sensible heat transfer to the air.

Sour Water Treatment

The sour gas stripper removes NH₃, H₂S, and other impurities from the liquid waste streams of the char-burning CFB, Gasifier cooling, Hydrogenation feed compressor, and CO₂ Knockout drum. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from syngas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and is sent to the char-burning CFB unit. The liquid from the Sour water stripper is sent to the Ammonia Stripper where the ammonia is removed and the resulting liquid stream is sent to the Waste Water Treatment system.

Water and Waste Water Treatment

Water and waste water treatment are accomplished by the Zero Liquid Discharge (ZLD) system. Plant water supply will provide service water, fire protection system water, system water, and makeup water to the circulating water system (wet cooling tower system basis). Additional makeup water to the circulating water system will come from reuse of treated wastewaters and storm water runoff. Blowdown from the circulating water system will be treated via a zero liquid discharge (ZLD) system to concentrate and remove solids, and recycle treated wastewater back to the circulating water system. The steam cycle makeup will be provided from process condensate of the Methanation system. A raw water tank and a filtered water/fire water tank will be provided to store water supplied from the water supply source. Filtered water will be provided to the service water system.

Flare System

Hydrogasification plant will be equipped with a single 100% capacity elevated and fully automated flare system. The purpose of the flare system is venting and disposal of waste gases from the gasifier and syngas cleaning systems any time during operation. The flare system is comprised of multiple relief valves discharging into a common header, knockout drum for liquids separation, and self-supporting, refractory-lined, carbon steel flare stack. The integrated ignition system complete with multiple propane-fueled pilot burners, and monitoring instrumentation is capable of instantaneous initiation and

maintaining of stable burning throughout the period of waste gas flow. The flare system will be designed to support planned and emergency flaring events. The examples of planned flaring events would be gasifier startup, shutdown, and ramping. The emergency flaring events could occur as a result of upset operating condition. Waste gas during the planned flaring events would be treated to reduce environmental impact. Flaring of untreated waste gases will be limited to emergency events.

2. General Arrangement

The major Hydrogasification plant components discussed above have been arranged in several technological islands separated by access roads and with adequate space for construction, operations, and maintenance. This arrangement is shown in the following general arrangement drawing of the commercial scale facility.

Major technological islands include:

- Coal handling Island - Coal receiving, storage and reclaim systems
- Gasification Island - Hydrogasifiers and Char Combustor
- Process Island - Syngas conditioning, Methanation, H₂, CH₄ and CO₂ processing systems
- Power Island - Steam turbine systems, and water storage and treatment systems
- Balance of plant Island - Cooling tower,
- Switch yard - High and medium voltage electrical equipment

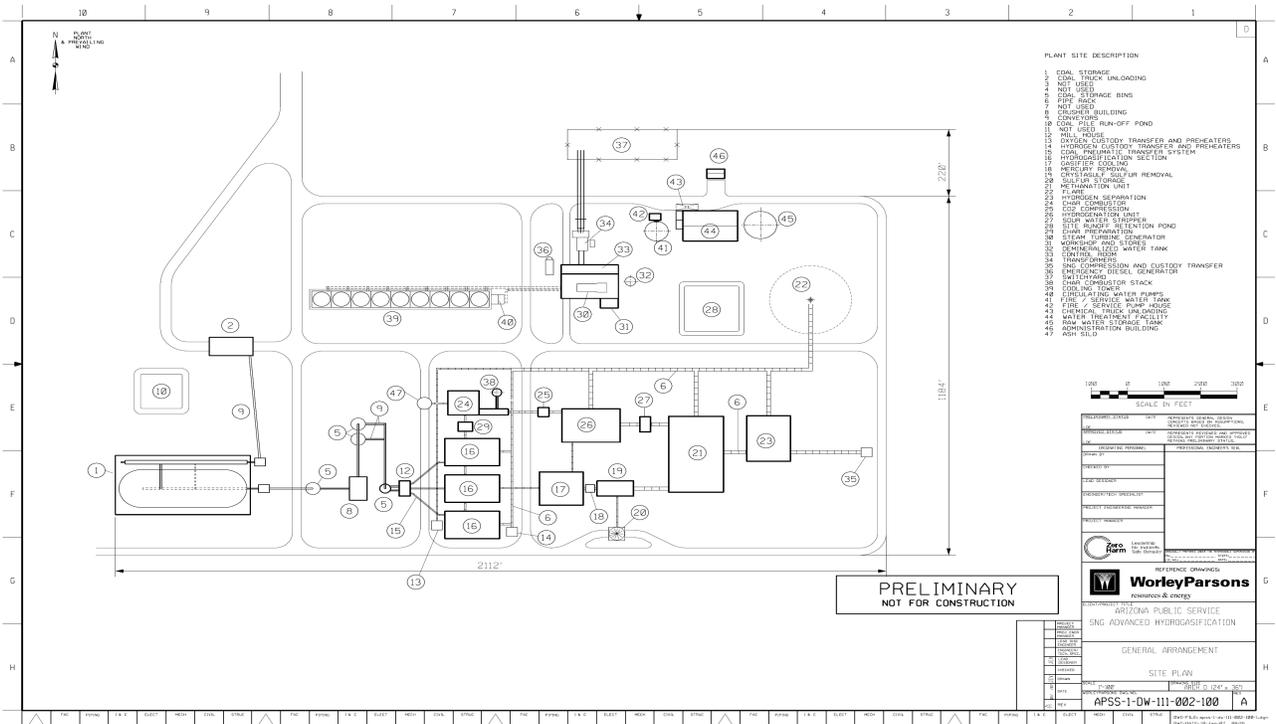


Figure VII-2 Preliminary Plant Lay-out (conceptual)

3. Preliminary Plant Cost Estimate and Economics: Preliminary cost estimates, energy efficiency analysis and market value investigations were completed in the first phase. These analyses establish a baseline for comparison of the APS Advanced Hydrogasification Process with the targets set by the DOE in Solicitation DE-PS-05NT42512-02. Present-value estimates were developed to test the DOE target of \$5 per million BTU cost of SNG (note: \$5/MBTU may be conservative as the number was developed in 2002 and this process targets commercial availability in the 2012 timeframe). Preliminary costs were estimated for a nominal 1,000-short dry ton/day plant (estimate based on a three trains). The original target appears to be achievable at \$5/MMBTU, particularly for the algae integrated plant. Uncertainties about hydrogen quantities in the final design, supply of renewable hydrogen and the cost of hydrogen, along with several other uncertainties will receive further attention in Phase II. Current estimates indicate that under some scenarios the cost would be below the target. Phase II will further develop design concept and alternative configurations to further explore the economics of the AHP process and the options that it might provide.

Coal Input (TPD)	3235 (3 trains)(1000 tpd)[100/(100-7.27%)]= 3235 tpd, AR		
SNG Out (MMSCFD)	118		
Power Net (MW)	131		
Overall Efficiency (%HHV)	70		
Capital (\$MM)	692		
O&M (\$MM)	45		
Coal Cost (MM\$/Y)(\$/T)	22/23		
CO ₂ Captured* (TPD)	1139		
Power Value (\$/MWH)	35		
H ₂ Supply	100% H ₂ from Coal	100% H ₂ from Grid Electricity	30/70 H ₂ from Wind/Grid
H ₂ Price (\$/Kg)	0.67	0.90	2.58
RSP SNG (\$/MMBtu) (HHV)	6.789	9.200	11.742

*Captured CO₂ is further converted into SNG through methanation process.

Table VII-2 presents the initial cost estimates for the process with a methanator and compares three projected SNG prices based on three different hydrogen supply sources. Table VII-3 provides cost estimates for the algae integrated process. While Table VII-3 demonstrates the cost advantages of co-producing algae and SNG the circumstances currently facing US electric utilities may favor the simple

methanator process under certain situations considering the advantages of the added renewable hydrogen component and the expanding market for renewable “electricity” and the accompanying premium pricing.

Table VII-3: Estimated SNG Price for APS AHP Algae Integrated Process

Coal Input (TPD)	3235 (three trains)		
SNG Out (MMSCFD)	101		
Power Net (MW)	108		
Overall Efficiency (%HHV)	78		
Hydrogasification Capital (\$MM) ⁺	692		
Hydrogasification O&M (\$MM) ⁺	45		
Coal Cost (MM\$/Y)/(\$/T)	22/23		
Algae Farm Capital (\$MM)	269		
Algae Farm O&M (\$MM)	27		
CO ₂ Captured* (TPD)	1139		
Power Value (\$/MWH)	35		
CO ₂ Value [#] (\$/T)	132		
H ₂ Supply	100% H ₂ from Coal	100% H ₂ from Grid Electricity	30/70 H ₂ from Wind/Grid
H ₂ Price (\$/Kg)	0.67	0.90	2.58
RSP SNG (\$/MMBtu) (HHV)	4.714	6.880	9.163

⁺: Hydrogasification capital and O&M cost was assumed same as “CO₂ into methanator” process.

*: Captured CO₂ is further converted into Biodiesel/Cattle Meal through algae process.

[#]: Net income from algae farm through the production of biodiesel and cattle meal.

A summary of the estimated plant costs is shown in Tables VII-4 and VII-5

Table VII-4 Plant Cost Summary

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Cost	Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingency Project	Total Plant Cost \$
1	Coal Handling & Preparation	\$21,901	\$5,705	\$11,491	\$39,097	\$3,512	\$9,341	\$51,950
2	Gasifier & Accessories	\$36,201	\$6,224	\$33,355	\$75,780	\$7,354	\$31,574	\$114,708
4	Raw Syngas Particulate Removal & Cooling	\$42,952	\$338	\$24,277	\$67,567	\$6,598	\$14,833	\$88,997
5	Acid Gas Removal/Sulfur Recovery	\$6,156	\$3,514	\$5,639	\$15,309	\$1,501	\$4,202	\$21,012
7	Other Gas Processes	\$48,856	\$20,082	\$37,776	\$106,714	\$10,351	\$23,413	\$140,477
10	Char Combustor, HRSG, Ducting & Stack	\$29,471	\$449	\$2,198	\$32,118	\$3,002	\$12,660	\$47,780
11	Steam Turbine Generator	\$34,374	\$692	\$9,632	\$44,699	\$4,074	\$6,456	\$55,229
12	Feedwater & Misc. Bop Systems	\$19,504	\$6,959	\$9,035	\$35,497	\$3,283	\$9,789	\$48,569
13	Cooling Water System	\$7,780	\$5,006	\$6,650	\$19,435	\$1,768	\$3,878	\$25,081
14	Ash Handling System	\$2,692	\$1,621	\$1,332	\$5,645	\$509	\$935	\$7,089
15	Accessory Electric Plant	\$7,373	\$4,841	\$8,806	\$21,020	\$1,816	\$3,928	\$26,764
16	Instrumentation & Control	\$3,632	\$960	\$2,890	\$7,482	\$671	\$1,175	\$9,328
17	Improvements To Site	\$1,646	\$14,899	\$8,512	\$25,057	\$2,446	\$8,251	\$35,754
18	Buildings & Structures	\$0	\$6,887	\$6,833	\$13,719	\$1,216	\$3,734	\$18,669
Total Cost		\$262,537	\$78,176	\$168,427	\$509,140	\$48,097	\$134,170	\$691,407

Notes:

1 Cost Basis of Sept 2006, (\$x1000)

2 Cost Estimate type is Conceptual

Client:		APS					Report Date:		08-Feb-07
Project:		Hydrogasification / Substitute Natural Gas							
		TOTAL PLANT COST SUMMARY							
Case:		POX H2 Gasification, CO2 for transport & Methanation Feed, CrystaSulf, and H2 Membrane							
Plant Size:		130 MW.net	Estimate Type:	Conceptual	Cost Base (Sep)	2006	(\$x1000)		
Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Cost	Bare Erected Cost \$	Eng'g CM H.O. & Fee	Contingency Project	TOTAL PLANT COST \$	
	1 COAL HANDLING & PREPARATION	\$21,901	\$5,705	\$11,491	\$39,097	\$3,512	\$9,341	\$51,950	
	2 GASIFIER & ACCESSORIES								
	2.1 Hydrogasification Reactor	\$36,201	\$0	\$29,923	\$66,124	\$6,483	\$29,043	\$101,649	
	2.2-2.3 Other Gasification Equipment	\$0	\$6,224	\$3,432	\$9,656	\$871	\$2,532	\$13,059	
	SUBTOTAL 2	\$36,201	\$6,224	\$33,355	\$75,780	\$7,354	\$31,574	\$114,708	
	3 ASU & HYDROGEN PLANT								
	3.1 ASU/Oxidant Compression	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
	3.2 Hydrogen Plant	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
	SUBTOTAL 3	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
	4 RAW SYNGAS PARTICULATE REMOVAL & COOLING	\$42,952	\$338	\$24,277	\$67,567	\$6,598	\$14,833	\$88,957	
	5 ACID GAS REMOVAL/SULFUR RECOVERY	\$6,156	\$3,514	\$5,639	\$15,309	\$1,501	\$4,202	\$21,012	
	6 SULFUR RECOVERY & TGTU	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
	7 OTHER GAS PROCESSES								
	7.1 Methanation	\$21,236	\$13,083	\$20,998	\$55,317	\$5,423	\$12,148	\$72,868	
	7.2 Hydrogenation	\$2,636	\$1,554	\$2,494	\$6,684	\$655	\$1,468	\$8,807	
	7.31 Hydrogen Separation Membrane	\$505	\$288	\$462	\$1,255	\$123	\$276	\$1,653	
	7.32 Hydrogen Purification	\$278	\$158	\$254	\$690	\$68	\$152	\$909	
	7.33 Hydrogen Compression (Reciprocating)	\$2,592	\$1,479	\$2,374	\$6,445	\$632	\$1,416	\$8,493	
	7.34 Gas Dryer(TEG Dessiccant)	\$581	\$332	\$533	\$1,446	\$142	\$317	\$1,905	
	7.35 SNG Compression	\$1,141	\$651	\$1,045	\$2,837	\$278	\$623	\$3,738	
	7.4 Sour Water Stripper	\$3,004	\$2,261	\$3,630	\$8,895	\$872	\$1,953	\$11,720	
	7.5 Flare Stack	\$401	\$0	\$234	\$635	\$62	\$140	\$837	
	7.6 CO2 Compression & Drying	\$16,225	\$0	\$5,138	\$21,363	\$1,989	\$4,670	\$28,022	
	7.7 Fuel Gas Piping	\$257	\$275	\$615	\$1,146	\$106	\$251	\$1,503	
	SUBTOTAL 7	\$48,856	\$20,082	\$37,776	\$106,714	\$10,351	\$23,413	\$140,477	
	8 POLYGEN OPTIONS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
	9 COMBUSTION TURBINE/ACCESSORIES	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
	10 CHAR COMBUSTOR, HRSG, DUCTING & STACK	\$29,471	\$449	\$2,198	\$32,118	\$3,002	\$12,660	\$47,780	
	11 STEAM TURBINE GENERATOR	\$34,374	\$692	\$9,632	\$44,699	\$4,074	\$6,456	\$55,229	
	12 FEEDWATER & MISC. BOP SYSTEMS	\$19,504	\$6,959	\$9,035	\$35,497	\$3,283	\$9,789	\$48,569	
	13 COOLING WATER SYSTEM	\$7,780	\$5,006	\$6,650	\$19,435	\$1,768	\$3,878	\$25,081	
	14 ASH HANDLING SYSTEM	\$2,692	\$1,621	\$1,332	\$5,645	\$509	\$935	\$7,089	
	15 ACCESSORY ELECTRIC PLANT	\$7,373	\$4,841	\$8,806	\$21,020	\$1,816	\$3,928	\$26,764	
	16 INSTRUMENTATION & CONTROL	\$3,632	\$960	\$2,890	\$7,482	\$671	\$1,175	\$9,328	
	17 IMPROVEMENTS TO SITE	\$1,646	\$14,899	\$8,512	\$25,057	\$2,446	\$8,251	\$35,754	
	18 BUILDINGS & STRUCTURES	\$0	\$6,887	\$6,833	\$13,719	\$1,216	\$3,734	\$18,669	
	TOTAL COST	\$262,537	\$78,176	\$168,427	\$509,140	\$48,097	\$134,170	\$691,407	

Table VII-5; Sampling of Costing for AHP Facility

VIII. To Be Accomplished in Phase II

1. Technical Challenges:

Bench scale testing is required to characterize the reaction residence time and kinetics. Additional aspects of the process design, including expanded cost and economic investigation, analysis and engineering development, are also required so the hydrogasification co-production plant can operate efficiently and economically.

The actual kinetics of western coal in the presence of high hydrogen at temperature and pressure is the most important design parameter for a hydrogasification reactor. In Phase I, conservative assumptions were made with respect to kinetics and conversion of coal to methane. Using the resultant hydrogasification reactor product, a Base Case product gas back end process was developed along with several alternatives, which could be implemented depending on the results of kinetics experiments in Phase II. In Phase II, the reaction kinetics will be experimentally determined, allowing the entire hydrogasification process to be optimized, including the alternatives for back end product gas processing. The bench-scale testing program will also generate data required for design of an engineering-scale reactor for field-testing in Phase III. Major experimental activities in Phase II will include:

Bench Scale Testing:

The APS Advanced Hydrogasification design concept will require bench scale tests to determine extent of carbon conversion in the timeframe, essential H₂/coal ratio, and refined temperature parameters. Kinetics of hydrogasification process needs to be developed to instruct the scale-up reactor design.

In addition, coal feeder technology for the hydrogasifier will require investigation. An initial design has been completed and will be tested in concept during Phase II. Other technologies for the coal feed system and their impacts on the hydrogasifier will be investigated in the proposed program of work. During Phase II additional design work and testing will be completed on the “Tip Burners”.

Assumptions for Phase II bench scale testing

Operation Conditions: 1600°F, 1000 psi;

Capacity/Unit: 5-15 lb/hr coal feed, 300-900 SCF/hr hydrogen feed

Engineering Scale Process Design:

Operating conditions of 1600°F and 1000 psi

Capacity/Unit: 50T/D coal feed; 170KSCF/hr hydrogen feed

During Phase I five key challenges were identified in the current AHP process that needs to be further considered and resolved as a part of Phase II.

Challenge #1: Engineering Scale Hydrogasification Reactor Design

- Double wall internal recycle entrain flow similar to ARCH reactor design
- Straight drop tube entrain flow design
- Fabrication challenges including materials

Challenge #2: Hydrogen Supply

- Require about 400 kg/hr hydrogen for 50 T/day coal feed.
- Possible methods:
 - Coal/char gasification followed by water-gas-shift for hydrogen production
 - Methane steam reforming
 - Electrolysis process with renewable (wind farm) and/or off-peak electricity input;

Challenge #3: Oxy-burner

- Oxy current Status: - 3 MW has been demonstrated; 30MW is under development
- Considerations for application within the AHP process

Challenge #4: H₂/CO₂ Methanator

- Required Conditions
 - 12 vol%(CO +CO₂)
 - 40 vol% H₂O
 - 400-800°F
 - \$750-1000 /ft³ catalyst cost
- Performance: 90% CO₂ conversion, 99% CO conversion.

Challenge #5: Dry Coal Feeder

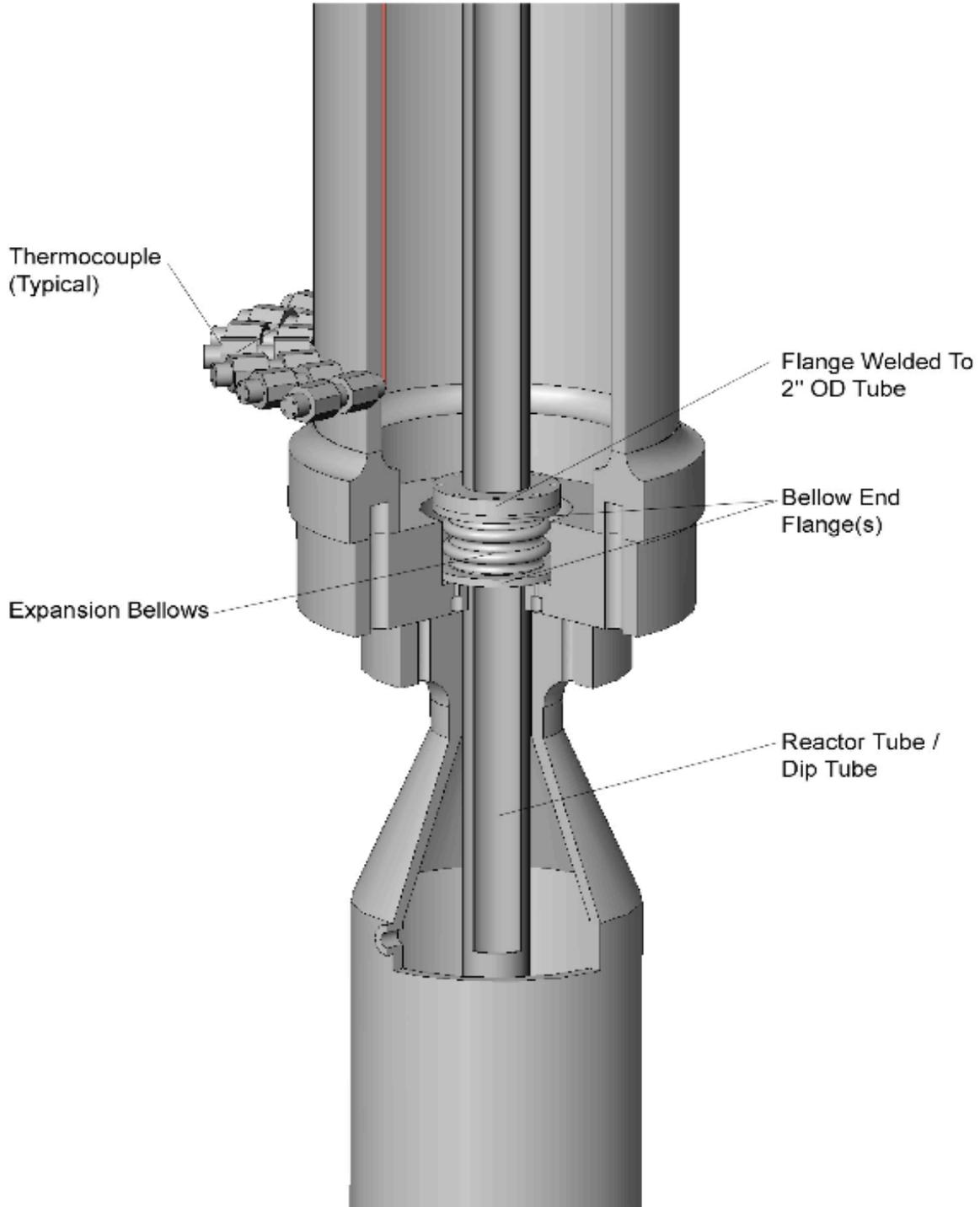
- Stamet Posimetric High Pressure Solid Feeder
 - Pressure up to 1,000 psi (March '07)
 - Design commercial scale: 600T/d
- Magnetic Screw Driver, Metal Fab, Vernon, NJ

The other system components are commercial technologies and utilization will require further investigation as to application and modification during phase 2. Notes and advisement will be included in Phase II reporting indicative of components or equipment that may need to be tailored to specific coal and site conditions.

Utilization of Test Results and Phase II Focus: The results of the bench-scale hydrogasification reactor tests will be used to guide the Phase II process/system engineering. During Phase II a design for the Phase III engineering-scale test facility, as well as the hydrogasifier operating conditions and hydrogen supply scheme will be finalized. Phase II engineering will focus on preparation for the Phase III engineering scale/pilot test facility. The preparation work in Phase two will include site priority selection criteria and selection process. The AHP team will consider the equipment necessary to the Engineering Scale facility to validate the test, and consider other equipment that might have value to the test, even if not a requirement. Permitting consideration and impact on location will be carefully reviewed and recommendations on site (based on permitting, land use and other criteria to be developed) will be completed prior to the conclusion of phase two. The team will develop a conceptual phase 3 test reactor and complete a preliminary fabricator selection process during phase 2. Phase II will include incorporating bench-scale test results into the system design and on conducting preliminary engineering to further ascertain the economic and CO₂ benefits of the AHP integrated process. Preliminary Design Basis and preliminary equipment specifications for major process equipment required in the Phase III engineering-scale test facility will be developed. Balance of plant engineering will be performed and basic engineering drawings developed including: plant configuration drawings, balance of plant flow diagrams and a conceptual layout for the engineering-scale test facility installation. Both process and balance of plant engineering will be based Phase II bench-scale testing, modeling and analysis. The Engineering Scale Facility will be designed so as to be an appropriate scale to promote a commercial step (and achievable with the available allocated funds). The economic, business and commercialization plans will be updated and expanded to assess the technical and commercial viability of the concept, including a cost/benefit analysis for demonstration and commercial activities that will be defined and reviewed with the DOE.

Figure VIII-1 Test Reactor Cross Section View

Reactor Foot Assembly Cross Section



2. Statement of Project Work Plan

Scope Of Work - In Phase II, the technology concept will be proven through bench-scale testing of the hydrogasification reactor, engineering and economic evaluation of the integrated plant, and development of a process design package for an integrated engineering-scale field test. Phase II will prepare for an Engineering Scale test facility and provide a integrated overview of a Commercial facility.

Task 3.0 - Phase II Program Management

APS, as the prime contractor, will have the responsibility for coordinating the work required to accomplish Phase II. APS will be responsible for project deliverables, including a topical report summarizing the findings for Phase II. APS will assure that Stakeholders (including the DOE/NETL Project Manager, Participant leads, the TAC members, and Contractor PM's) are informed and involved in the on-going process of the project. APS will participate in project review briefings, Annual Contractor's Review Meetings and develop the GO/NO GO recommendation for the Phase III Engineering Scale Test Facility (ESTF).

Task 3.1 - Bench Scale Testing

Expand and refine the Test Plan developed in Phase I and conduct bench-scale tests, utilizing Phase I testing and analysis as a foundation. Conduct bench-scale testing in accordance with the Test Plan and document results, providing an acceptable level of information from testing to allow for go forward decisions. Include Stakeholder review and input. Burner

Task 3.2 - Process Design Concept

The Phase I process design analyses will be updated in parallel with the bench-scale testing. The process design diagram, energy and material balances, and other process considerations will be revised to reflect information from bench-scale tests and new information collected during Phase II. RX design

Task 3.3 Plant Design

Update the Design Criteria, preliminary specifications and other design documents developed in Phase I to further develop an understanding of the comparative economics of the basic options for the AHP process and offer consideration as to the impacts of CO2 requirements that the AHP process will accommodate. Preliminary design concept for the engineering scale demonstration and commercial facility. Develop Design Criteria for the Balance of Plant and preliminary specifications for the engineering scale test facility equipment required to implement the APS Hydrogasification Process

(AHP). Conduct constructability analyses and examine start up sequences in order to fully develop the engineering scale test facility design and support a comprehensive Go/No Go decision for its construction in Task 3.0.4. Pilot test site plan and equipment

Task 3.4 - System Analysis and Cost Engineering

Update commercial facility cost forecasts developed in Phase I Task 2.5. Using this updated forecast, prepare equipment, construction, start up and operating cost forecasts and recommend contingencies and allowances appropriate to the level of confidence inherent in the cost forecast. Prepare forecast costing both to support economic and cost analysis's of the AHP process and to support the Engineering Scale facility. Plan for periodic review of analysis and input from other Stakeholders.

Task 3.5 – Facilitate Risk Management

Provide an independent review of research progress to provide critical review of planned work and task results. The Technical Advisory Committee shall perform the review.

Task 3.6 – Environmental, Health, Safety, Regulatory and Compliance

Review and compile a structured tracking document of the regulatory and EHS hurdles for the Project. Consider regulatory, safety, and environmental compliance issues in preparation for the regulatory applications, permits, etc for the Phase III Engineering Scale facility (both construction and operation). The siting for the Phase III pilot will be highly dependent on permitting analysis and accomplishment in Phase II. Highlight EHS concerns that might impact schedule, cost, engineering, permitting, and construction to the appropriate team member so that information can be integrated into work plans and estimates. Each of the Participants may play a role in compiling this information, with APS responsible for assembling the interim and final reports. Permit and DOE environmental report were completed in Phase I for Phase II testing.

Task 3.7 - Business Planning

Update and maintain the Business Plan developed for the commercial hydrogasification facility, development of at least three alternatives that might include varying size or location of the facility. As a corollary to the Engineering Scale business case examine the economic and business aspects of constructing and operating a commercial AHP facility. The Participants will each contribute to this Task; APS will coordinate the participant's work and edit the final reports. The Participants have knowledge and experience as both customers and suppliers, this knowledge will be used to consider how best to position the business case for Phase III anticipating successful results from Phase I and II testing.

Task 3.8 Carbon Capture and Recycle Testing and Commercial Design

Develop a program including testing of the engineering scale algae recycle project at the Red Hawk Station. Development and execution of algae testing at a coal fired generating station.

Technology Transfer Plan

As part of the technology transfer plan, the APS Team will develop material including technical papers, fact sheets and summary reports. Results of proposed work will be made available to DOE via reports, both electronic and printed. Technical papers will be presented at association meetings and industrial conferences. The APS Team will make use of media releases to major industry publications and wire services to highlight program results.

Expected Impacts and Benefits

The most significant impact/benefit from the development of hydrogasification SNG technology is the introduction of a new and diverse process for gasifying fossil or biomass fuels.

Impacts: The hydrogasification, with the co-production of electricity, produces SNG more efficiently and at lower cost than other gasification alternatives, allowing commercial SNG production to expand the domestic supply of natural gas. This will stabilize both fuel cost and supply for electric utilities and their customers. Water consumption by the hydrogasification process is less than current gasification processes. This allows electric utilities to meet growing demand in the West for electricity while protecting water resources. Depending on site and other specific conditions, hydrogen to operate the hydrogasifier could be generated from renewable sources, including biomass and wind. CO₂ is minimized in the hydrogasification process, and with the complimenting algae recycle flue gas from the power generator is also cleaned up.

Applicability: The production of SNG from hydrogen can be integrated with existing natural gas transportation infrastructure, without modification. This allows SNG production to occur at a wide range of locations, limited only by access to a gas pipeline and a source of carbon fuel and hydrogen. Successful production of substitute gas with energy levels (BTU) equivalent to natural gas at a reasonable price would immediately increase the on line production of currently existing natural gas electric generating stations.

Risks: During Phase I the team explored several alternatives and options on the alternatives, resulting in the recommended Process. While no fatal flaws have been found that would prevent development of the concept, there are significant engineering and manufacturing issues that must be resolved. The pressure

and temperature relationships and the need to feed solids and gases into the reactor vessel at optimum have been noted previously along with other concepts that need to be optimized and tested.

Potential for Breakthrough: The proposed program of work offers potential breakthroughs in (1) direct combination of hydrogen and carbon to create methane and (2) integrating hydrogen as an energy source, creating a large market for renewable hydrogen, adding to the promotion of a hydrogen based infrastructure (3) CO₂ capture and recycle for further use in the energy chain. It is currently assumed that around 2025 (less than two decades) the US consumption of natural gas will exceed the use of gasoline, without a portion of that need being filled by substitute natural gas the price of natural gas (and gasoline) will severely impact the electricity markets and the overall US energy costs. Any process that intends to fulfill that need must incorporate successful CO₂ capture. Carbon recycle is a bonus of this process

Preliminary Cost and Economics: Present-value estimates were developed to test the target of \$5 per million BTU cost of SNG. Preliminary costs were estimated for a nominal 1,000-ton/day plant. The Team believes that there is significant room for process optimization and cost reduction as well as revenue generation from co-produced electric power.

The cost and efficiency studies in phase one are preliminary but offer a good deal of encouragement that a commercial scale hydrogasification plant using the Team's current process flow model would be commercially viable. A good deal more technical and cost analysis needs to be completed before detailed numeric conclusions can be drawn. Phase two will continue to build on the positive cost results to date further refining and exploring the possibilities.

Phase II Economic Analysis: Phase II economic and market analysis will prepare the project for justification of commercial value or cancellation. The economic portion of the project will consider the energy/fuel alternatives to this project. AHP and alternatives will be judged based on cost, probability of commercial viability, time frame for introduction and potential for financing. AHP will be compared to alternatives with regards to suitability for siting, fuel mix and emissions profile. The economic section will examine a host of factors that are likely to impact selection and success of technologies. A sampling of these factors might be:

- Carbon capture and CO₂ rules
- Value of renewable in fuel mix
- 'Oil and natural gas import projections

The economic section will include a business plan with budget forecast and fuel production projections. The business plan will examine the aspects of an AHP plant based on the strictures of a new business venture.

“WHAT GETS US IN TROUBLE ISN'T WHAT WE DON'T KNOW,
IT IS WHAT WE ARE SURE WE DO KNOW.” MARK TWAIN

IX. Comparison to Goals

Objectives - The objective of the proposed program of work is to develop and demonstrate at an engineering-scale, a coal hydrogasification-based process for co-production of SNG and electricity with near-zero emissions meeting the following performance targets: (1) overall process efficiency greater than 50%; (2) SNG cost less than \$5/million BTU; (3) capture and utilization of CO₂ equivalent to 90% of emissions from power production; (4) water usage at least 50% less than SNG from gasification/syngas methanation; (5) the capability of accepting hydrogen (preferably from a renewable source) as a supplemental source of energy; and (6) the ability to use low-rank Western coals.

Results of Phase I – Phase one has sustained and confirmed that all of the objectives are achievable with the AHP process. Based on work to date efficiencies are greater than 50%, cost is at (or below) \$5/MBTU, capture of CO₂ could be close to 100%, water usage is sufficiently below the alternatives, renewable hydrogen is technically feasible, and the process is designed for western coals.

Technical Merits: Based on Phase I results the APS Advanced Hydrogasification Process is expected to have the following technical advantages:

- ◆ The ability to gasify high moisture and ash content western sub-bituminous and lignite coals without severe energy penalties associated with other gasification technologies.
- ◆ Created high efficiency process which produces SNG at 900 psi and 985 BTU/sc within the required parameters for pipeline introduction according to El Paso Natural Gas criteria
- ◆ The hydrogasification reactor operates at a significantly lower temperature than partial oxidation reactors. This is expected to significantly reduce ash fusion and slagging problems, particularly with western sub-bituminous and lignite coals.
- ◆ Hydrogasification is an exothermic reaction between coal and H₂
- ◆ The hydrogasification reactor produces a higher fraction of methane than partial oxidation reactors, thereby reducing the "lift" required by methanation.
- ◆ The process cleans sulfur and utilizes the carbon in CO₂ eliminating the need for expensive, commercially available "back end" clean up processes for sequestering CO₂.

- ◆ The process allows the introduction of renewable hydrogen into the process, providing a much needed renewable energy addition to electric utility generation portfolios, reducing CO₂ production and providing a significant market to stimulate the development of renewable hydrogen production.
- ◆ Assessments show that the process will be more efficient than alternatives, due to lower reaction temperatures & higher methane production in the initial reaction.
- ◆ Water consumption for the process will be lower than with other gasification technologies because of reduced water requirements for ash handling.
- ◆ While there are clearly several areas of risk and uncertainty that require tests and development, the APS Advanced Hydrogasification Process uses a large portion of commercially available components, which are expected to speed its commercial application.
- ◆ The process provides for several alternatives for the recycle of the carbon in the CO₂ eliminating special separation and capture operations. The recycle extends the use of carbon within the system.
- ◆ The concept of adding hydrogen rather than removing carbon appears to have a sustainable future.
- ◆ The process as developed in Phase One allows for significant variation to meet a variety of conditions and site objectives.

Production of SNG through AHP appears to have considerable advantages over comparable systems based on the research completed during the 1st Phase. Based on these encouraging results the AHP program has moved into Phase II. The primary purposes of the second phase are to demonstrate coal hydrogen reaction and production estimates, to facilitate engineering and design efforts that will be necessary to move into phase three and to refine the market and economic analysis for AHP products. Success in Phase II is highly dependent on the coal conversion and efficiency that the team is able to achieve in the test reactor.

“THERE AIN’T NO RULES AROUND HERE, WE ARE TRYING TO ACCOMPLISH SOMETHING.” THOMAS EDISON

“CONTINUOUS IMPROVEMENT IS BETTER THAN DELAYED PERFECTION.” MARK TWAIN

X. Gasification Economics

1. Introduction -

The time frame and possibly the relevance of the AHP process for the gasification of coal will depend on how various economic scenarios play out over the next few years. It is possible that the process will be in great demand within three years, before it is fully developed. Or it might not be seen as needed until well into the next decade. And while it is always possible that it will be replaced by other technologies that are superior technically or earlier to market there is only a small possibility that gasification (in some form) will not be a part of the next generation of energy technologies.

The AHP process is still in development and as of now the need appears fairly certain. But how that need plays out in the market place will be driven by factors that are only beginning to emerge. This section examines several obvious possible alternative scenarios. This is not an exhaustive review nor is it necessarily the most likely. We have examined those possibilities that seem most likely to us at this point in time and with our western utility focused perspective. The examination is a beginning step in placing the project in a broader perspective of need, economics and time frame. During the second phase additional clarity will be developed on this perspective.

Overview:

The over riding driver in the current energy equation is oil, and correspondingly natural gas. Classical economic theory contemplates that increased demand drives up the price. Higher prices attract new investment in the means of production (materials, labor, machinery and so on). Higher rates of production create a subsequent surplus of product, driving prices down as manufacturers compete for business. Unfortunately, classical economics does not understand how to deal with a depleting resource – such as oil or natural gas. Since both production and consumption are relatively inelastic (ignoring the impact of political, cultural and environmental disruption), changes in investment – even huge changes in investment- are unlikely to bring about a corresponding increase in supply. Historically decreasing supply in the field of energy has resulted in transfer to new sources of fuel, with corresponding greater or lesser distress depending on the conversion period and supply.

The world oil market has become relatively inelastic in the sense that large increases in upstream investment no longer produce contemporaneous increases in supply. Even assuming there are no political obstacles, cultural disruptions, weather problems, or geographical challenges to delay exploration and

production, it still typically takes many years to develop a new oil field. In addition, our ability to bring new production on-line is further limited by the political objectives and cultural challenges of the producer nation.

As oil and natural gas deplete, suppliers will attempt to charge as much as the market will bear. That, in turn, will force demand destruction as higher prices and availability curb consumption. Unfortunately, since American oil demand per household has been relatively inelastic since 1982, demand destruction can only occur if the economy is forced into a recession, and/or Americans make substantial changes to their lifestyle and/or there is a transition to new sources of fuel.

It can now be observed that the transition won't be entirely smooth. Consumption has not responded to indications of stress in the supply. Nor have new fuel sources risen to the level of obvious replacement for oil. The AHP process may be one of the alternatives that can play a role in our transition away for the current heavy reliance on oil.

Portions of the above section abstracted from an article by Ronald R. Cooke, Cultural Economist, April '07

2. Potential Scenarios

As a starting point for our analysis we have chosen five basic scenarios. The scenarios center around the two major factors currently playing out for electric utilities – (1) rising cost of fuel driven by oil and (2) increasing need for carbon capture and other environmental restrictions. The scenarios are then divided between little or slight change from current circumstances, increased environmental regulation, increased fuel cost driven by oil and combination of high fuel cost and rapidly increasing environmental regulation. The base case of fuel and environmental concerns staying relatively the same as they are today provides for a baseline of comparison, if not a reality based likelihood.

Scenario Factors

We have considered several factors in judgment of each scenario:

- Market Demand
 - Demand for electricity has continued to climb at the historic 3% per year.
 - Ironically as global warming increases the demand for electricity, and therefore power plants will climb significantly faster than the historic rate as humans deal with the increased summer time temperatures and overall erratic weather.
- CO2 emissions reduction value
 - Nearly all scenarios for reduction of CO2 include restrictions on electric generation
 - The value of removing CO2 has not been clearly established. The ten Northeast States that have put in place a mandatory cap and trade program probably represent the least aggressive policy that is likely to be implemented over the next three years. That program targets a 10% reduction in all plant emission within ten years, which would require a very considerable reduction for new plants and considerable retrofit work on existing facilities.

- Natural gas price
 - When the RFP for this project was distributed natural gas at \$5/mmbtu was a competitive reality. In the two years since long term contracts for NG are up about 30%. And even with large introductions of LNG by the end of this decade the 2010 price of natural gas could well be above \$10/mmbtu.
 - Natural gas has many applications for which it is ideally suited and many others that significant amount of infrastructure is in place to utilize. This in place need will put pressure on the price of natural gas into the foreseeable future.
- Utility regulatory environment
 - Need for power in the US has grown over the past several years in the absence of plant construction. The era of “merchant plants” created a small reserve of un-used generation. That reserve has been eroded to a very thin margin.
 - Renewable portfolio requirements
 - Western utilities in particular are interested in providing “renewable” based power in order to retain access to the lucrative California market.
 - Other states are showing signs of following suit placing utilities in need of renewable generation.
 - In January of 2007 the centralized government of China told power companies that 5 percent of their electricity will have to come from renewable energy sources by 2010, as the country tries to diversify away from fossil fuels to power its fast-growing economy.
 - The definitional parameters of “renewables” remains unclear slowing development, but any process tied to generation will need to include a renewable option.
 - Ratepayer investment limitations
 - Utilities are looking to garner greater PUC commitment on placement of generation capital cost in rate base before committing to development. This will be an additional complexity and delay prior to the start of construction.
 - PUC prior approval may not be achievable, but if it is it will place the PUC in a decisive position in the selection of future generating unit design and fuel type.
 - Stranded NGCC plants
 - Natural Gas Combined Cycle plants are an ideal choice for electric generation in the US for a long list of reasons. These include siting adjacent to load centers, low CO2 emissions, ease of construction with equipment that is reliable, low O&M costs, and operational experience.
 - A considerable amount of NGCC generation exists that will be difficult to employ if the price of natural gas cannot be stabilized.

The comparisons consider five basic alternatives for the generation of electricity in the near term:

- AHP
- Nuclear
- Pulverized Coal
- IGCC
- Combined Cycle, Natural Gas

						Alternatives				
Future	CO2	Market	Product	Utility	AHP					
Scenarios	Removal	Demand	Mix	Mandate	Technology	AHP	Nuclear	Pulverized	IGCC	N Gas
Indicate product mix						SNG		Coal	(POX)	CC
1 "Normal"	Assume	Assume	SNG	economics	AHP w/ Algae	1	3	4	2	5
Fuel supplies stable	gradual	10% per	& other	Adverse to	Mix of products	Need	may be	dirty but	too	Meets
Economy stable	introduction	year	products	change	1st plant '15	small	best	easy	many	enviro
No new conflicts	of tax and		for \$		algae best \$		but slow		unknowns	&
	cap & trade				Higher \$ product	\$8 btu	Cost?			tech.
2 Environment "rules"	Aggressive	Big	Mix	Reduce CO2	AHP w/ Algae	3	5	1	2	4
Enviro becomes the issue	tax & cap/tr	trouble	SNG & bio	Must use renew	use renew. H2	needed	best	Dirty	too	meets
CO2 removal mandate	escalating	mtg load	fuels	Pour in \$	Algae to fuel		but		much	Regs
Aggressive Cap & Trade	over next		Emphasis	New ideas OK	1st plant '11	\$15 btu	slow		CO2	
	5 yrs		on clean		Clean products					
3 Oil price up	CO2 reg	Big	Mix	Get NG!	AHP	3	5	4	2	1
GS estimate \$100 bbl '09	is slow & has	trouble	SNG & bio	Pour in \$	delay algae	Need	Easy	We have	Need	Fuel?
LNG over \$10/ mmbtu '09	allowance for	mtg load	fuels	New ideas OK	use lot's of H2		to get	the fuel		
Conflicts in Mid East	production		Emphasis		1st plant '11		fuel			
			on fuel		Emphasis - fuel	\$15 btu				
4 Modest impact of 2 & 3	CO2 regs &	Meet	Mix	Reduce CO2	AHP w/ Algae	4	3	2	1	5
Combine effects of 2 & 3	pressure to	load	SNG & bio	Must use renew	Use renew H2	need	clean	Dirty	No CO2	Best
Oil price up 10 to 20%/yr	produce fuel	but not	fuels	Pour in \$	algae to fuel	for fuel	& fuel		answer	balance
LNG \$10 after 2010	Elect favored	easy	Both clean	New ideas OK	use lots of H2	& clean	but slow			
Cap & trade w/ modest %	for central		& fuel	Get NG	1st plant '12		& \$\$			
	clean up		needs		Products	\$10 btu				
					clean & fuel					
5 Increasing impact of scenarios 2 & 3	Mandated w/ cap & trade	Straines	Coal out	High cost		4	5	1	2	3
				reduce CO2	Good fit	\$15	Demand	too	CO2?	Fuel?
								dirty		
Total (Rank 1 to 5 per area, high best)						15	21	12	9	18
<i>Assumptions -</i>						<i>No "catastrophic" scenario assumptions</i>				

Table X-1; Comparison of Scenarios

The Table above is a starting point for analysis as the project goes forward. Rather than a definitive conclusion the format has been developed to encourage discussion within the team and to facilitate planning.

3. Comparison

Will hydrogasification be one of the mainstays of future energy needs for the US or will other technologies emerge? Several factors and many as yet unknown variables will effect the answer. We have considered a few of the most significant factors.

- Cost
 - Hydrogasification appears to be competitive with other technologies that are likely to be available after 2010.
 - The price of hydrogen may be the largest factor in the cost equation for hydrogasification
- CO2 emissions
 - The extent of regulation and requirements for CO2 removal or re-use is a very open question at this time. Using the “Intergovernmental Report”, April 2007 as a base a 5 degree increase in world wide average temperature is now inevitable (some of the effects include all arctic ice disappears, 97% of coral reefs are severely damaged or disappear, Amazon forest disappears) some of the effects will cause serious consideration of CO2 capture in the near term.
 - The AHP process has a very chance to be one of the most environmentally friendly with CO2 capture and re-use either with hydrogen, algae or a combination.
 - If other technologies continue to rely on CO2 sequestration underground this may be the determinate factor in the success of the AHP process. Geologic sequestration faces a number of significant unanswered questions including whether the CO2 will actually remain in the geologic formations.
- Product mix (H2, Power, SNG)
 - One of the factors yet to be determined is the ratio of hydrogen, SNG and power to come out of an AHP process.
 - This ratio will have technical and economic impacts on the process. It is possible that the ultimate design process will be flexible with regards to this ratio allowing circumstances and site specifics to dictate the mix.
 - The hydrogasification tests are independent of the hydrogen source – if results are positive, each site can decide on the hydrogen source and how to use the syngas. Feasibly one could make hydrogen or liquids depending on the markets.
 - The cost to provide hydrogen to the AHP system will be a major factor in the ultimate success of the process, fortunately there appear to be a number of alternative choices being developed.
- Utility system compatibility (price stability, electric system stability, etc.)
 - Electric utilities are structured to favor price stability over pricing instability that may average to a lower price
 - Electric utilities are required to provide system stability which leads to choices that are not purely economic or technical
 - Electric utilities are long lead planners building facilities that are expected to be productive a minimum of 50 years.
- Algae as a part of the mix
 - Algae recycle opens up a number of additional option to the AHP design and utilization
 - Algae recycle appears to be an ideal adjunct to AHP with addition to the back end emissions from natural gas power plants
 - Inclusion of Algae in this project should spur other development and utilization ideas at existing coal plants and other applications.

4. Alternative system costs/benefits in potential future scenarios

- Pulverized coal
 - Currently pulverized coal is the obvious choice for electric generation based on cost, if future environmental regulation can be ignored. However CO₂, NO_x, particulate and other restrictive regulation is clearly a part of the future equation.
 - Coal has many advantages that will keep it in the generation mix for some time to come; the caution is how to proceed with a technology that faces unclear regulation. Pulverized coal plants are intended to be productive for at least 50 years and after the fact retro fits can imperil their viability (consider the Mohave coal facility)
 - Delivery will also restrict the use of pulverized coal for generation as the nations rail infrastructure has little excess capacity and in some regions aging and ill maintained tracks will actually reduce capacity.
 - Generation plants can be located at the coal fields but the cost of line losses and the difficulty in siting transmission lines will be a constraint
 - Future Gen -
- IGCC
 - IGCC is highly regarded and improving rapidly through extensive R&D efforts.
 - The two step process and questions concerning use of western coal makes it an unlikely fuel source in the west.
- Natural gas combined cycle
 - NGCC is clean and relatively easy to site, can be built in a relatively short time using existing technology. Operators know how to run the plants (but there are few operators), low O&M, site near load centers
 - Cost of fuel is a major concern
 - LNG sites continue to be proposed but few have reached construction stage, and if the current projection holds true that Russia and Iran have over 50% of the reserves the US will need AHP or another similar process if we are to continue the use of NG as a fuel.
- Nuclear
 - Is a clean power source with many benefits
 - It has reasonable operating cost, although it is expensive to build
 - There is a long lead time for siting and construction
 - Public opposition is well documented
 - Nuclear power is highly regulated

Conclusion to The Comparison Table

The most likely scenario is number five. It is possible that another lesser scenario prevails or that one that is more catastrophic than those considered will consume the other options. If number five were to be what occurs AHP would be ideally suited to play a significant role.

This is obviously a very simplified look at how the future may play out, but it provides a structured format for discussion and investigation as the AHP project proceeds. Timing is of critical importance for the known energy sources and those that might play a role. Today we have shown that AHP could play a role. Tomorrow we hope to show how.

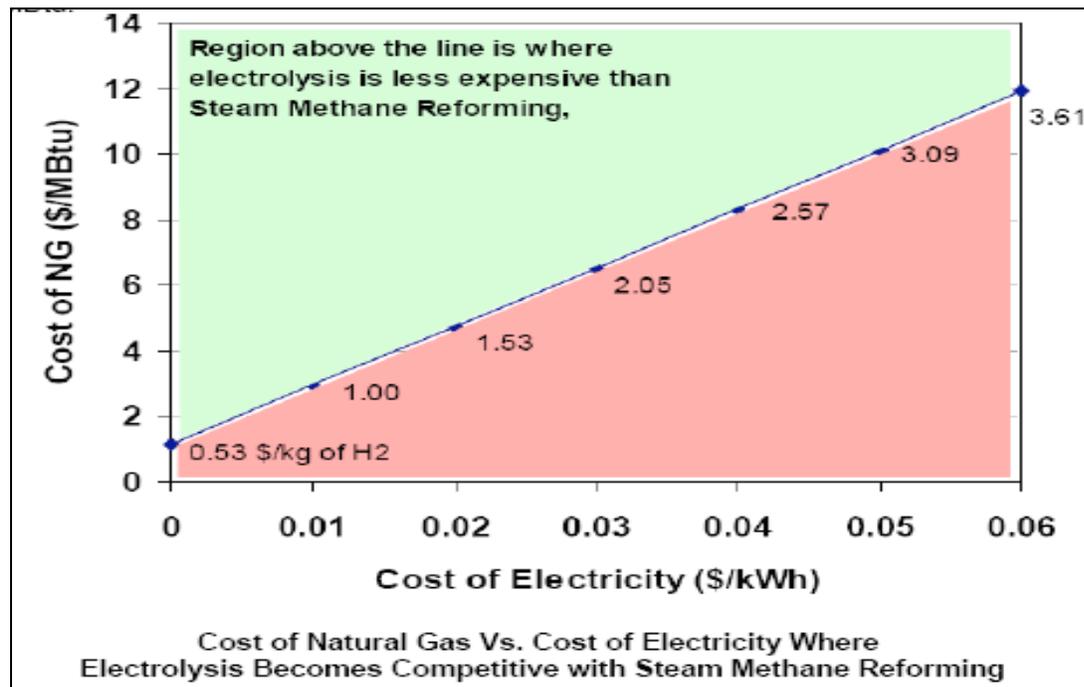
“WITHOUT THE VISION OF A GOAL, A MAN CANNOT MANGE HIS OWN LIFE, MUCH LESS THE LIVES OF OTHERS.”
TEMUJIN – GENGHIS KHAN

5. Consideration of Hydrogen

The cost of Hydrogen plays a significant role in the economics of hydrogasification. While there are a number of sources and potential sources for hydrogen, the best choice for hydrogasification and other processes sensitive to the cost of hydrogen is not yet clear. The evolution to those sources is a critical factor for hydrogasification. The project has looked in depth at several sources of hydrogen for hydrogasification, including an extensive study of wind generated hydrogen, and will continue to track hydrogen production from coal, off peak nuclear, grid and “green” sources.

An analysis (Texas Gulf Coast Feasibility Study) of the cost of hydrogen production by the present method of steam-methane reforming (SMR) was compared with the cost of producing hydrogen by conventional electrolysis. The graph, below, relates the cost of natural gas and the cost of electricity at which hydrogen produced by electrolysis is equal to the cost of hydrogen produced by steam-methane reforming. For example, if electricity costs \$0.02/kWh, hydrogen by electrolysis costs less than hydrogen by SMR, if the cost of natural gas is greater than \$4.50/MBtu.

Figure X-1; Hydrogen Cost Comparison



As demonstrated in this graphic there is reason for optimism as to the cost impact of hydrogen on hydrogasification. During Phase II the team will further explore the opportunities for delivery of hydrogen for hydrogasification and the economic impacts.

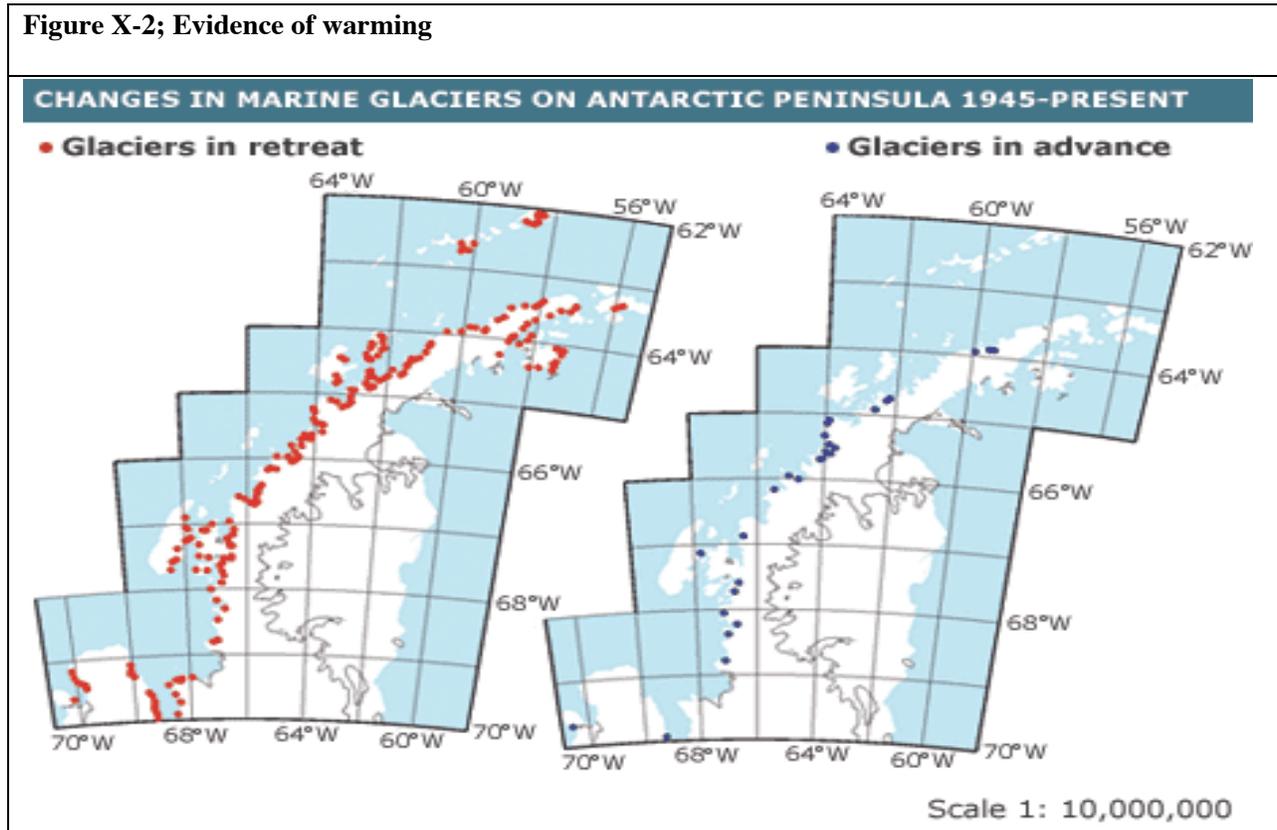
“CHANGES IN CLIMATE ARE NOW AFFECTING PHYSICAL AND BIOLOGICAL SYSTEMS ON EVERY CONTINENT.”
UN’S PANEL ON CLIMATE CHANGE

6. Climate Change

The planet's climate is constantly changing. The global average temperature is currently in the region of 15C. Geological and other evidence suggests that, in the past, this average may have been as high as 27C and as low as 7C. Currently there is concern that a rapid human-induced warming has overtaken the natural fluctuation that has serious implications for the stability of the climate.

The greenhouse effect refers to the role played by gases, which effectively trap energy from the sun in the earth's atmosphere. Without them, the planet would be too cold to sustain life as we know it. The most important of these gases in the natural greenhouse effect is water vapor, but concentrations of that are changing little and it plays almost no role in modern human-induced greenhouse warming. Other greenhouse gases include carbon dioxide, methane and nitrous oxide, which are released by modern industry, agriculture and the burning of fossil fuels. Their concentration in the atmosphere is increasing - the concentration of carbon dioxide has risen by more than 30% since 1800. The majority of climate scientists accept the theory that an increase in these gases will cause a rise in the earth's temperature.

Figure X-2; Evidence of warming

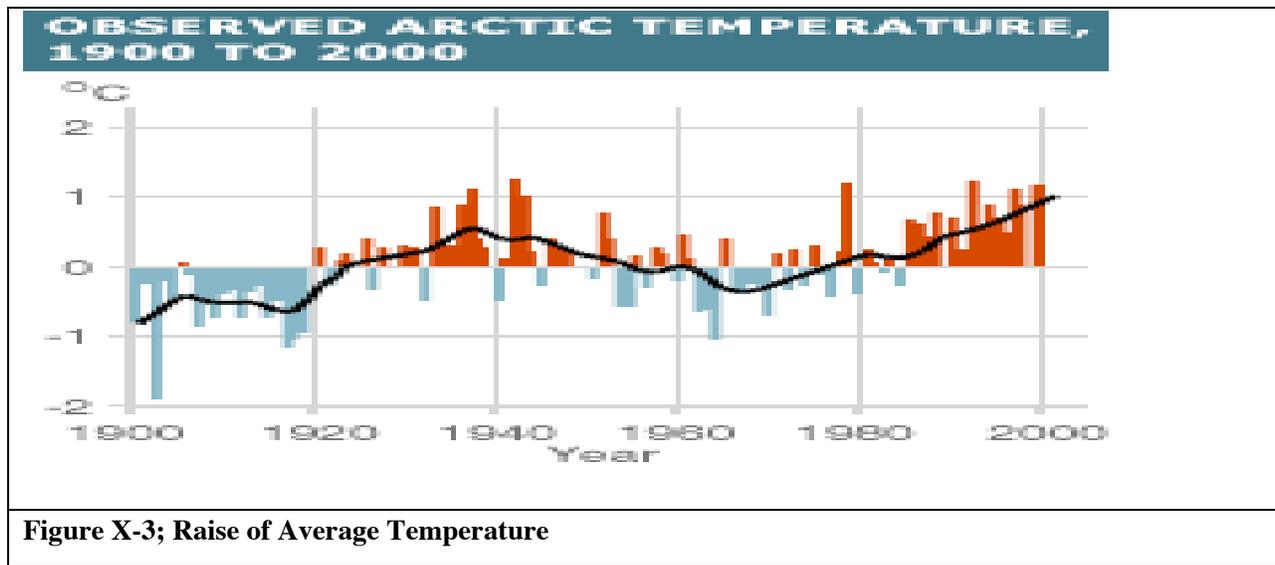


In 2006 the average temperature in central England was the highest ever recorded since the CET series began in 1659. Temperature records go back to the late 19th Century and show that the global average temperature increased by about 0.6C in the 20th Century. Sea levels have risen 10-20cm - thought to be caused mainly by the expansion of warming oceans. Most glaciers in temperate regions of the world and along the Antarctic Peninsula are in retreat; and records show Arctic sea-ice has thinned by 40% in recent decades in summer and autumn. There are anomalies however - parts of the Antarctic appear to be getting colder, and there are discrepancies between trends in surface temperatures and those in the troposphere (the lower portion of the atmosphere).

Current climate models predict, if nothing is done to reduce emissions, a global temperature increase of 1.4-5.8°C by 2100. Even if we cut greenhouse gas emissions dramatically now, the effects would continue because parts of the climate system, particularly large bodies of water and ice, can take hundreds of years to respond to changes in temperature. It also takes greenhouse gases in the atmosphere decades to break down. It is possible that we have already irrevocably committed the Greenland ice sheet to melting, which would cause an estimated 7m rise in sea level. There are also indications that the west Antarctic ice sheet may have begun to melt, though scientists caution further research is necessary.

Effects

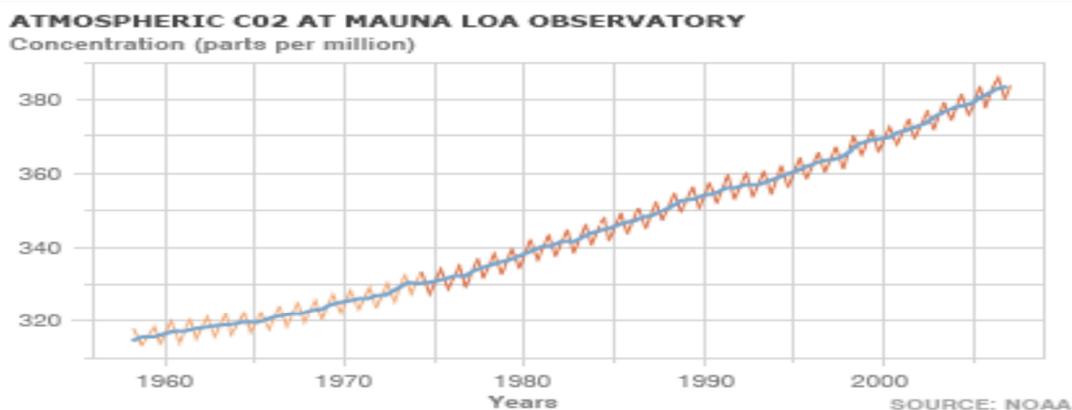
During the decade from 1993 to 2003 CO₂ concentrations grew from 357.04 ppm to 375.64 (mean annual carbon dioxide concentrations as measured at Mauna Loa in Hawaii). The potential impact is huge, with predicted freshwater shortages, sweeping changes in food production conditions, and increases in deaths from floods, storms, heat waves and droughts. Globally, we can expect more extreme weather events, with heat waves becoming hotter and more frequent. Scientists predict more rainfall overall, but say the risk of drought in inland areas during hot summers will increase. More flooding is expected from storms and rising sea levels. There are, however, likely to be very strong regional variations in these patterns, and these are difficult to predict. Plant and animal extinctions are predicted as habitats change faster than species can adapt, and the World Health Organization has warned that the health of millions could be threatened by increases in malaria, water-borne disease and malnutrition.



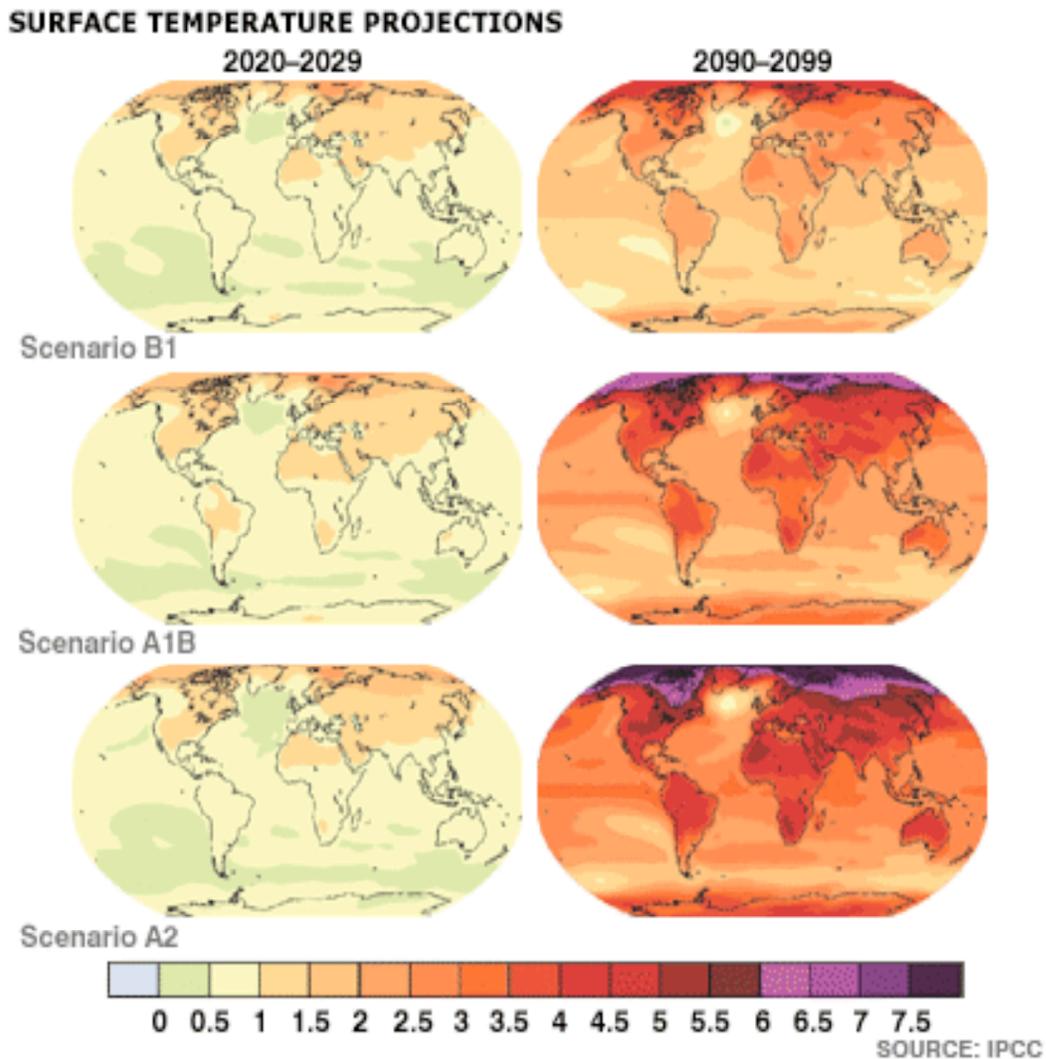
The precise relationship between concentrations of carbon dioxide (and other greenhouse gases) and temperature rise is not known, which is one reason why there is such uncertainty in projections of temperature increase. Global warming will cause some changes that will speed up further warming, such as the release of large quantities of the greenhouse gas methane as permafrost melts. Other factors may mitigate warming; it is possible that plants may take more CO₂ from the atmosphere as their growth speeds up in warmer conditions, though this is not certain. Scientists are not sure how the complex balance between these positive and negative feedback effects will play out.

Adapted from BBC NEWS: Published: 2006/01/30 08:52:31 GMT © BBC MMVII

Figure X-4; CO₂ Concentrations



Carbon dioxide is the main greenhouse gas, its rise since the industrial revolution is clear. Burning coal, using oil and deforestation all place CO₂ into the atmosphere. CO₂ levels are approaching double the concentration that was in the atmosphere before the Industrial Revolution.

Figure X-5; Temperature Projections

The Intergovernmental Panel on Climate Change predicts that temperatures are most likely to rise by 1.8C-4C by 2100. But the possible range is much greater; 1.1C-6.4C. The maps above show how a range of three different scenarios will affect different parts of the planet. The emissions scenarios, used to create the maps above, are based on a range of detailed economic and technological data. These versions of the future consider different population increases, fossil and alternative fuel use, and consequent CO₂ increases.

Chart from BBC NEWS: Published: 2007/02/02 11:52:27 GMT © BBC MMVII

“THE KEY THING NOW IS THAT SINCE WE KNOW THE INDUSTRIAL AGE HAS CREATED IT, LET’S GET OUR ACT TOGETHER AND DO EVERYTHING WE CAN TO ROLL IT BACK.” GOVERNOR ARNOLD SCHWARZENEGGER

"WISELY AND SLOW; THEY STUMBLE THAT RUN FAST" SHAKESPEARE

XI. Summary

The APS/SNG Team has accomplished a great deal in Phase I. The team has reviewed four alternatives for hydrogasification and considered additional options of each alternative. From those alternatives the process that was viewed as the most flexible with the least uncertainties was selected. The process selected is believed to be the most efficient but will be refined and undoubtedly modified in Phase II to increase efficiency and enhance the likelihood of commercialization.

A new reactor concept was developed based on concepts internal to the team and NETL, and similar to what at the time was known of the Osaka Arch reactor. Since the reactor design concept was chosen by the team we have had the good fortune to add one of the major Osaka team members to our team. The reactor is simple and we believe ideally suited to hydrogasification. It should be noted that we are not working off specific design information from ARCH but prior to adding Mr. Noguchi had determined that the ARCH concept was the closest to what we believed would be the most successful application.

The selected process has the ability to transfer the carbon in the waste CO₂ to methane with the addition of hydrogen in the methanation step. This is a major addition to the project that was not envisioned when the project was first introduced. Moving away from CO₂ isolation and sequestration would allow this process to move beyond the short term (and unlikely) concept of geologic sequestration into a far more viable and long term application on carbon conversion.

The Project added additional CO₂ flexibility with the algae recycle process addition. This concept would add an alternative for CO₂ recycle, provide a means of recycling the CO₂ that would be produced as waste gas at combined cycle plants and feed carbon back into the system as additional fuel.

Flexibility is a significant additional value in the overall process as it is currently proposed. There are numerous considerations for flexibility throughout the current process. There is flexibility in handling and using greenhouse gases, there is flexibility in the means of electricity co-production, there are options for hydrogen and there are various means of achieving renewable credits. As CO₂ policy evolves, along with renewable targets, the flexibility of the AHP process adaptability will be of considerable benefit. Western US utilities are seeking electric production processes that are CO₂ "free" and will help meet stringent renewable mandates.

There were numerous other achievements in the First Phase including the addition of several key contributors including Dr. Xiaolei Sun, Dr. Al Weimer, Mr. John Boyle and Mr. Fuyuki Noguchi. The major products delivered in Phase one have been included in Quarterly and other reports. Of particular note is the extensive work that Nexant performed on the ASPEN model with a host of alternative considerations, the excellent engineering and design criteria work done by WorleyParsons, the many design concept ideas from the University of Colorado, the Energy Efficiency studies by Dr. Sun, renewable hydrogen study in conjunction with Air Products, and a number of other deliverables on market and other features of the project. Most if not all of the Phase one deliverables will be expanded and enhanced in the Phase II work.

This is a unique project. It has exceptional potential yet is within the grasp of current technologies. It envisions and provides a way to use coal for fuel without greenhouse gas emissions and in a form that is easily deliverable. The Project could expand the life of hundreds of natural gas plants and pave the way for additional combined cycle plants near load centers. It combines renewable with existing carbon. This is a process that would be stable, sustainable and highly efficient. This project offers the opportunity to move electric production for the US into the next generation.

“OUR DOUBTS ARE TRAITORS AND MAKE US LOSE THE GOOD WE OFT MIGHT WIN.”

WILLIAM SHAKESPEARE

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