Gas Turbine World

Correspondence
Gas Turbine World
P. O. Box 447
Southport, CT 06890 USA

Courier Deliveries
Gas Turbine World
654 Hillside Road
Fairfield, CT 06824 USA
Telephone (203) 259-1812

Editor-in-Chief
Robert Farmer
Tel (252) 354-3164
E-mail: rfarmer@ec.rr.com

Editor & Publisher
Victor de Biasi

Subscriptions
Peggy Walker
Telephone (203) 259-1812
Facsimile (203) 254-3431
E-mail: gtwsubs@gmail.com

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Advertising Offices

England
Sally Donlevy
Telephone 44 20 8946 5347
Facsimile 44 20 8944 1419
E-mail: sally@donlevy.co.uk

Japan
Masahiko Yoshikawa
Telephone 3 32 35 5961
Facsimile 3 32 35 5852
E-mail: mashy@fa2.so-net.ne.jp

United States
James Janson
Telephone (203) 255-2225
Facsimile (203) 226-0061
E-mail: publications.grp@snet.net

Cover This 250 MW IGCC demo plant is scheduled to start test operations this July to confirm the design performance and durabilty of Mitsubishi air-blown gasification system and integrated M701DA combined cycle power island. See page 42

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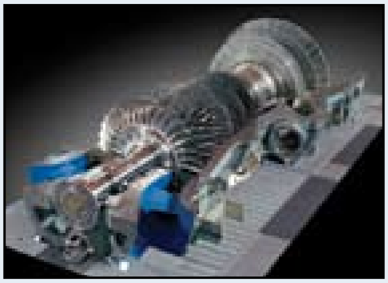
Energy companies worldwide are turning to gasification projects for producing electric power, hydrogen, synthetic fuels and chemicals from low grade coals, refinery residues, waste and biomass, page 11



IGCC plants
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Where have we been and where are we headed?

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Rest of the world is keener on gasification and less interested in utility power, Page 17

There is a surge of activity around the world for developing projects to generate electric power, synthetic fuels, hydrogen and chemicals though the gasification of coal, refinery residues, waste and biomass

In planning for this special issue, our GTW editors set out to assemble a comprehensive tabulation of proposed IGCC and related gasification projects around the world.

They considered all candidate projects, regardless of feedstock and product, whether to produce electric power, steam, fuels or chemicals. Provided the gasification process could apply to power generation for internal or external use, it qualified.

Also, there was no attempt to screen out specific projects on the basis of whether or not likely to actually get built, knowing full well that many of them are still to be permitted or funded and may not materialize.

The one provison was that new projects had to be reported by more than one source as a legitimate proposal approved by executive management for study and possible development.

We entered into this task with full recognition, as one industry expert noted, that this would be a "Herculean task" and impossible to make all-inclusive.

The result is considered to be a reasonably complete freeze-frame snapshot of the status of the industry up through the end of February 2007.

We owe thanks to EPRI, the Gasification Technologies Council and industry project engineers for cooperating in the collection of this data, although GTW takes responsibility for its accuracy.

Proposed Projects in North America

Activities in the United States seem evenly divided between pure IGCC projects to generate power from coal, and poly-generation projects to generate electric power, hydrogen, synthetic natural gas, chemicals, liquid fuels. Many proposed projects in Canada are related to oil sands recovery operations.

Several proposed gasification projects in Canada are related to oil sands recovery schemes to dispose of waste products generated by the bitumen-to-light-crude upgrading and also produce hydrogen needed for the upgrading process itself.

Many of the projects in the United States, by contrast, are for electric utility power generation or industrial poly-generation. Several of the IGCC projects listed are currently the subject of preliminary Front-End Engineering Design (FEED) evaluation.

Main purpose of these FEED studies is to determine the technical and economic viability of proposed commercial plant designs and site selections for internal budget cost estimates and investor backing.

Projects selected for the first round of investment tax credits under the Energy Policy Act (EPAct) of 2005 are highlighted in yellow. Three of the nine projects that qualified are pure IGCC plants, i.e. Duke Cinergy Indiana, Mississippi Power, Tampa Electric Polk II.

Two of them are polygeneration projects that include IGCC electric power generation. They are being developed by BP Edison in California (designed to operate with carbon dioxide capture and sequestration) and Texas Energy Eastman in Texas.

We updated the NRG Energy listing to report Mitsubishi as gasification and gas turbine technology partner for a series of proposed IGCC projects.

The initial NRG announcement of this development said that a joint project in western New York State is currently in contract negotiations with the New York Power Authority.

Project	Year	Gasifier	Engr	GT Model	Net Output	Comments
Agrium, Kenai, Alaska						
sub-bituminous	2011	GE Energy	N/A	N/A	200 MW poly*	*ammonia, urea
Alma, Michigan						
coal	N/A	N/A	N/A	N/A	MW + poly*	*plus methanol
American Electric Power, Ohio						
coal	2010	GE Energy	Bechtel	2 x Fr 7FB	630 MW	
American Electric Power, West Virginia						
coal	2010	GE Energy	Bechtel	2 x Fr 7FB	630 MW	
Baard Energy/Rentech, Ashtabula, Ohio						
Illinois coal	N/A	Shell	N/A	1 x Fr 6FB	100 MW poly*	*35,000 bpd
Basin Electric , South Dakota						
PRB coal	N/A	GE Energy	N/A	GE Frame	N/A	
BP Edison Refinery, Carson, California						
pet coke	N/A	GE Energy	N/A	1 x Fr 7FB	390 MW poly*	*plus hydrogen
Citgo, Lake Charles, Louisiana						
pet coke	N/A	N/A	N/A	N/A	MW + poly*	*plus hydrogen
Clean Coal Power, Vandalia, Illinois						
coal	N/A	N/A	N/A	N/A	MW + polygen*	*100,000 bpd naphtha
CoP Refineries, Various Sites						
pet coke	N/A	CoP E-Gas	N/A	N/A	hydrogen*	*hydrogen/steam
DKRW, Medicine Bow, Wyoming						
So Wyom coal	N/A	GE/Rentech	N/A	N/A	140 MW poly*	*11,000 bpd dist/ naphtha
Duke/Cinergy , Edwardsport, Indiana						
coal	N/A	GE Energy	N/A	2 x Fr 7FB	630 MW	
Energy Northwest , Port Kalama, Washington						
coal/pet coke	2011	N/A	N/A	N/A	600 MW	

Outlook for coal-based IGCC power generation

After more than 20 years of development and test, IGCC power plants are still fighting an uphill battle for utility acceptance.

There is a general belief that the technology is not ready for commercial consideration, as evidenced by the poor reliability record of several of the demonstration plants that have been built and tested, and that IGCC plants cost 10-20% more to build than pulverized coal steam plants

For the past few years, a new generation of refinery-based IGCC plants in Europe have been operating at better than 90% availability in commercial service, so that project engineers who continue to question IGCC availability and reliability have lost their credibility.

In contrast, the issue of relative costs is a legitimate concern because nobody has a handle on the real costs for an apples-to-apples comparison. With materials and construction costs for large capital projects escalating at a rapid pace, cost estimates are obsolete before they are made public.

Further, widely quoted differences in plant costs are often based on comparative plant equipment costs without regard to the expense of providing ultra-low NOx, SOx and particulate emissions performance or carbon capture.

Once you include the capital cost of enabling both type plants to operate with 85-90% CO_2 removal, for instance, utility planners now concede the cost gap disappears and may even favor IGCC technology.

Continuing advances in gas turbine and associated gasification technologies have a real potential for further improving project costs. A 15-20% increase in gas turbine output alone, for example, can reduce $/kW cost of IGCC plants by that same percentage.

Coal properties vary widely with rank and source

Gasification performance can be negatively impacted by high moisture and ash content of lower rank coals. Certain gasifiers are said to be unsuitable or require de-rating when using them. Penalty can be a 2-3 percentage point loss in overall IGCC plant efficiencies.

Typical coal properties x wgt	Pittsburgh No. 8	Illinois No. 6	Wyoming coal	N. Dakota lignite
Moisture	5.20%	12.20%	30.24%	26.80%
Carbon	73.80%	61%	48.18%	45.82%
Hydrogen	4.90%	4.25%	3.31%	3.11%
Nitrogen	1.40%	1.25%	0.70%	0.70%
Oxygen	5.40%	11%	11.87%	14.68%
Chlorine	0.07%	0.07%	0.01%	N/A
Sulfur	2.13%	3.28%	0.37%	0.69%
Ash	7.10%	6.95%	5.32%	8.20%
Heat Content (HHV)	13,260 Btu/lb	10,982 Btu/lb	8,340 Btu/lb	7,810 Btu/lb

Source: EPRI June 2006 Bismarck presentation

A few basics of IGCC design

Gasification of feedstock such as coal, pet coke, refinery residues and biomass in the presence of oxygen and steam in a fuel-rich environment produces a combustible synthetic gas (syngas) made up primarily of hydrogen and carbon monoxide.

This gas mixture has on the order of one-fourth the heating value of natural gas. This means that gas turbines require four times more fuel on a volume basis when burning syngas than when operating on natural gas.

For NOx reduction, a significant amount of nitrogen diluent is injected with the fuel to suppress combustion NOx. The increase in mass flow contributed by the resulting low-Btu syngas and nitrogen mixture can add 20-25% to gas turbine power output.

Integrating a combined cycle and gasification island involves bleeding high-pressure high-temperature air from the gas turbine compressor for use by an air separation unit (ASU) to produce industrial grade oxygen for the gasification process. In return, clean, pressurized syngas fuel is supplied to the gas turbine.

The ASU supplies pressurized ni-

Getting IGCC ready for commercial marketplace

In this section

Growing government and industry support for a CO_2 cap and trade system to limit greenhouse gas emissions, and environmental concerns over pulverized coal steam plants, is making IGCC power generation more attractive to utilities and developers

Over the next 6-12 months, with several commercial projects moving beyond the preliminary design phase, we can expect to learn a lot more about competitive design features, cost, performance and guarantees of IGCC reference plant designs being offered by GE Energy, Mitsubishi and Siemens for commercial operation in the 60-Hz marketplace.

At this point, it appears that IGCC technology is on the short end of a steeply uphill competitive struggle with conventional coal-fired plants -- both on the basis of the lack of proven commercial experience and evidence that it cannot compete economically.

All three of the major OEMs have developed or acquired proprietary gasification technologies which enable them to optimize in-house design integration of F-class and G-class gas turbines with enhanced gasifier designs that can be adapted to different feedstock and site conditions.

And all three are offering similar IGCC reference plant designs based on a 2x1 combined cycle power block configuration that, in the case of F-class machines, are similarly rated at around 600-650 MW net plant output.

In the meantime, Shell, ConocoPhillips and other technology suppliers remain active in the market offering their own brand of gasification technology through commercial alliances with engineering and EPC partners.

GE reference plant targeting COE parity with SCPC plants

Coal-based IGCC reference plant is expected to operate with a COE of $56.40 per MWh, on a par with supercritical coal plants when you add their emissions cleanup costs.

GE Energy is working in alliance with Bechtel on a standardized reference plant for a nominal 630 MW integrated gasification combined cycle (IGCC) design.

Using benchmarking studies against modern supercritical pulverized coal (SCPC) plants, GE has set targets for economics and performance of initial plants expected to come on line in the 2010 time frame.

Publicly stated emphasis is on achieving cost-of-electricity (COE) parity with pulverized coal plants, but some industry experts say that is not enough for follow-on designs:

☐ **Capital cost.** Must come in at $1400 to 1500 per kW (in 2005 dollars) for a complete greenfield plant.

☐ **Dependability.** Provide 98% reliability and 90% availability with cycling and load-following operation.

☐ **Efficiency.** Deliver at least 40% net plant efficiency (HHV) operating on bituminous coal feedstock.

☐ **Emissions.** Set new standards for coal-based power to earn emission credits and offer CO_2 capture-ready design.

At the Gasification Technologies Council (GTC) conference in San Francisco in 2005, GE explained that plant comparisons should take into account the cost of reconciling emissions differences between the two technologies.

They set $1450/kW (in 1Q 2005 dollars) as a realistic benchmark for the capital cost of a comparably sized super-critical pulverized coal plant.

And they estimate its COE at $52.10 per MWh based on heat rate and expected operating and maintenance costs, 90% availability factor, current coal pricing.

Then they add $4.30 per MWh as the penalty cost of NOx, SOx and mercury reduction offsets for super-critical coal plants to achieve emissions parity with IGCC.

This effectively set the baseline $56.40 per MWh COE reference cost (and target) for IGCC to match and beat.

Capital cost target

Backing out the IGCC reference plant cost estimates for coal feedstock and O&M, and assuming an 86% availability factor, the resulting plant capital cost target works out to around $1600 per kW, also in fixed 1Q 2005 dollars.

This is about 10% higher than the $1450 per kW cost of the benchmark super-critical pulverized coal plant, if

IGCC reference plant performance

Preliminary plant design is rated at 629 MW net output with an estimated 8845 Btu/kWh heat rate (38.6% efficiency HHV) on Illinois Basin coal containing 3.23% sulfur and 12.25% ash on a dry basis.

Gasification feedstock and ASU input

Dry coal feed	5,372 tons per day
Pure oxygen feed	4,894 tons per day
Coal heating value (HHV)	12,650 Btu per lb dry

IGCC plant gross rating

Gross gas turbine output	464 MW
Gross steam turbine output	300 MW
Combined gross output	764 MW
Auxiliary power (debit)	(135 MW)

IGCC plant net rating

Net power output	629 MW
Heat rate (HHV)	8844 Btu/kWh
HHV efficiency	38.6%

Mitsubishi 250 MW demo plant on target for mid-2007 testing

Advanced two-stage air blown gasifier will be scaled up for a 650 MW commercialized plant powered by a G-class gas turbine for 48-50% IGCC plant efficiency.

Clean Coal Power R&D Co. in Japan is getting ready to start operation of an air-blown coal based 250 MW IGCC plant at the Nakoso power station.

It was designed and built to roughly one-half commercial scale as a demonstration unit to prove out new technologies for a new generation of advanced air-blown commercial plants. Highlights:

☐ **Plant output.** Rated at 220 MW net plant output and 42% LHV efficiency on sub-bituminous feedstock and 135 Btu/scf syngas.

☐ **Combined cycle.** Powered by syngas M701DA gas turbine with air extraction, heat recovery steam generator, and oversized steam turbine.

☐ **Gasifier**. Dry feed air-blown entrained flow gasifier sized to process 1700 tpd coal feedstock, membrane water wall, cold gas cleanup.

☐ **Emissions.** Below 5 ppm NOx with selective catalytic reduction and 8 ppm SOx with wet chemical absorption for sulfur removal.

Mitsubishi designed and supplied the gasification and combined cycle for the plant under contract to a development consortium of utilities that formed Clean Coal Power R&D Co. for the express purpose of designing, building and operating the project.

The demonstration plant design is best described as a partially integrated coal-based IGCC system with a dry feed air-blown entrained flow gasifier.

The oxidant for gasification is supplied primarily by compressor air extracted from the gas turbine and further pressurized by a boost compressor for delivery to the gasifier.

A relatively small air separation unit is also included in the gasification system to produce 1.25 million cubic feet of nitrogen per hour. The nitrogen serves as an inert transport gas for injecting the coal into the gasifier.

This ASU is only about 20-25% the size needed for a comparably rated oxygen-blown gasification plant. Typically, these larger units consume about 10% of an IGCC plant's MW output and represent about 15% of total plant capital cost.

Oxygen byproduct

With nitrogen production the main purpose of the ASU, the oxygen byproduct is used to enrich the gas turbine extraction air supplied to the gasifier.

Enriching the air flow makes gasifier operation more stable, according to the project engineers, and enables the IGCC plant to change load more easily.

Since the ASU operates at constant throughput regardless of plant load, it helps make up for any drop in air flow to the gasifier when gas turbine compressor performance falls off at higher ambient temperatures.

Air-blown syngas fuel has a heating value typically in the range of 130-135 Btu/scf which is about half the heating value of syngas produced by oxygen-blown gasifiers.

The much higher volume of low-Btu syngas fuel increases the mass flow through the gas turbine and exhaust flow to the heat recovery steam generator of the combined cycle plant.

Syngas 701DA gas turbine

Syngas combined cycle is designed around MHI's 130-MW 701DA gas turbine, heat recovery team generator, and condensing steam turbine. Seawater will be used for plant cooling.

Typically, in a natural gas-fired combined cycle, the steam turbine provides roughly 50% of plant output.

Here, for the IGCC design, the steam turbine is rated at around 120 MW to make use of additional steam generated by the gasifier.

The HRSG is equipped with a selective catalytic reduction section to limit exhaust emissions to less than 5 ppm NOx. Reportedly, this is about one-third the NOx emissions produced by pulverized coal plants in Japan.

Project engineers say they elected to go with relatively modest D-class gas turbine technology (nominal 2200ºF inlet temperature) and inlet guide vane control in keeping with demo plant design goals.

Net efficiencies over 42%

The demo plant is rated at 250 MW gross plant output and 48% LHV efficiency on syngas fuel. With parasitic consumption losses, mainly to power gasification equipment and the small ASU, the plant is rated at 220 MW net output at 42% efficiency.

Siemens reference plant rated 630 MW net 38% HHV efficiency

Nominal 630 MW combined cycle reference plant, designed for coal-based integrated gasification operation on low rank coals, is powered by two SGT6-5000F gas turbines.

The Siemens combined cycle reference plant can be integrated with a variety of gasification processes such as ConocoPhillips' E-Gas, Shell, GE (Texaco) and Sustec Future Gen (which it now owns) for coal-based IGCC operation.

Typical plant design and performance are shown here for a 2x1 "F-class" combined cycle configuration and ConocoPhillips gasifier design template for sub-bituminous coal feedstock. Basic plant design:

☐ **Combined cycle.** Two 232-MW SGT6-5000F gas turbines, two three-pressure level HRSGs, and one-300 MW steam turbine.

☐ **Gasifier train.** Two 50% two-stage ConocoPhillips E-Gas technology slurry-fed gasifier trains, one for each gas turbine.

☐ **Power output.** Design rated at 644 MW net plant output with an HHV heat rate of around 9,000 Btu/kWh (38% efficiency).

The plant design featured 99% sulfur removal and recovery, 90% mercury removal, syngas moisturization, nitrogen dilution of the syngas for 15 ppm primary NOx control, and selective catalytic reduction of the gas turbine exhaust for further reduction to 3 ppm.

For operational flexibility, the design study also assumed the use of a wet cooling tower for plant cooling since an air-cooled plant design would be restricted to dry locations.

Estimated plant cost

ConocoPhillips reported on cost projections of the design study at the October 2005 Gasification Technologies Council conference. As pointed out, the capital cost of IGCC plants varies with coal rank and site specifics.

The budget estimate for a mid-West site and Pittsburgh No. 8 coal or pet coke, for example, came to around $1400 per net kW (overnight EPC cost in constant 2005 dollars).

The same plant using Illinois No. 6 coal for feedstock cost around $1475 per kW versus $1535 per kW for Powder River Basin sub-bituminous coal. The 5-10% higher cost attached to the lower rank coal is due to their lower heating values (characteristic of high moisture level and high ash content coals).

These estimates include a 20% allowance for contingency and contractor profit, but do not take into account various owner costs associated with project development, permitting, transmission, plant startup and commissioning.

Such costs can add 10% or more to the total plant cost, according to ConocoPhillips, depending on plant ownership structure, siting issues, and other project-specific factors.

SGT6-5000F for IGCC

Back in 2004, Siemens chose the

Reference plant designs. Differences shown for two 600 MW class reference plants designed around E-Gas gasifiers and SGT6-5000F combined cycle. Mid-west plant has a wet cooling tower versus dry cooling for the mine-mouth project. The gasifiers (one per gas turbine) process 8340 Btu/lb (HHV) sub-bituminous coal.

Design Conditions	Mid-west Site	Mine-mouth Site
Altitude and ambient	500 ft and 50°F	5,000 ft and 45°F
Feed rate (as received)	8,300 tpd	7,300 tpd
Oxygen (95% volume)	4,700 tpd	4,100 tpd
Combined Cycle		
Gross plant output	780 MW	670 MW
Auxiliary power	135 MW	115 MW
Net plant output	645 MW	555 MW
Net heat rate (HHV)	9000 Btu/kWh	9100 Btu/kWh

Next generation IGCC projects and technologies

FutureGen is the backbone of international government and industry collaboration for advanced IGCC technology development efforts.

With the goal of kick-starting commercial deployment, the program is aimed at building and operating a prototype next generation coal-based plant to demonstrate the feasibility of near-zero emissions power generation and hydrogen production.

In addition, the plant will be designed for 90% carbon capture and permanent disposal of carbon dioxide by injection for enhanced oil recovery or for storage in geological formations.

The target for carbon dioxide capture and sequestration is a minimum of 1 million tons per year increasing to 2.5 million tons.

Later this year, FutureGen is expected to announce the gasification and gas turbine technologies and suppliers for the nominal 300 MW demo plant to be built in Texas or Illinois. The estimated plant on-line date is 2012.

Better performance lower costs

Many executives in the utility industry are convinced that IGCC suffers from a serious "cost gap" in comparison to advanced super-critical pulverized coal (SCPC) plants.

The gap amounts to a 10-15% premium in the capital cost of building a coal-based IGCC plant (some say, more) and about 5% higher cost of electricity (COE) as compared to a super-critical pulverized coal plant.

An important engineering development goal of the FutureGen program is to bring down construction and operating costs to make IGCC the clear economic choice over super-critical pulverized coal plants.

This has already been done, to some extent, by specifying CO_2 capture which is relatively simple and inexpensive with IGCC, but difficult and expensive for pulverized coal plants to match.

Focus will also be on carrying out cost-saving gas turbine and gasification design developments that will increase plant output and efficiency.

The attraction of IGCC

The growing importance of IGCC technology is due primarily to its excellent environmental performance for coal-based power generation.

In addition to allocating $700 million to the estimated $1 billion FutureGen project, the U.S. Dept. of Energy is providing funding for two other projects under its Clean Coal Power Initiative.

In a cost-shared arrangement with the Southern Company and Orlando Utilities, $235 million will go towards a 285-MW IGCC plant with an advanced KBR "TRIG" air-blown gasifier design.

Timetable calls for construction to start later this year (2007) and the start of commercial operation in 2010. The gasifier feedstock will be western sub-bituminous coal.

DOE has also awarded Excelsior Energy a $35 million grant for development and preliminary engineering work on its Mesaba I project in northeastern Minnesota. Proposed plant is nominally rated at 600 MW net output and is also expected to start service in 2010.

Currently, the project is in the midst of regulatory hearings related to its application for approval of a power purchase agreement with Xcel.

There are currently no plans for carbon capture at these plants, although Excelsior has been claiming that the plant can be readily converted in the future.

Baseline analysis

DOE commissioned a study of comparably rated gasification, coal and natural gas-fired plant designs to establish a baseline economic model for evaluating different IGCC plant designs.

Three commercially available gasification systems (GE Energy, Shell and ConocoPhillips), all operating on Illinois #6 coal and matched to F-class gas turbine technology, were included in the study.

These were compared with sub-critical and super-critical pulverized coal steam plants as well as a natural gas-fired F-class combined cycle plant. Assumed fuel prices were $1.34/MMBtu for coal and $7.46 for natural gas.

Coal-steam plants include wet SO_2 scrubbers (gypsum byproduct type) and all plants were analyzed with and without systems for 90% carbon capture.

The total cost of capture plants includes extra equipment to compress the carbon dioxide to 2500 psi for pipeline delivery and for enhanced oil recovery injection or sequestration.

The IGCC plant design concept used two advanced F-class gas turbines and a reheat HRSG delivering 1800 psig steam turbine throttle steam.

Assumed throttle and reheat temperature was 1050ºF for non-capture operation and 1000ºF in the CO_2 capture case.

Each of the gasification island de-