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March 16, 2007

Blanca Bayo
Director, Office of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399

RE: Docket No. 070098-EI, Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant

Dear Ms. Bayo,

Please find enclosed an original and 15 copies each of the supplemental testimony of Richard C. Furman filed on behalf of Intervenors, The Sierra Club, Inc. (Sierra Club), Save Our Creeks (SOC), Florida Wildlife Federation (FWF), Environmental Confederation of Southwest Florida (ECOSWF), and Ellen Peterson.

Thank you for your attention to this matter.

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Sincerely,

Michael Gross
Earthjustice
111 S. Martin Luther King Jr. Blvd.
Tallahassee, FL 32301
(850) 681-0031

CC: All Official and Interested Parties

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ORIGINAL

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant
_______________________________________/

DOCKET NO.: 070098-EI

SUPPLEMENTAL DIRECT TESTIMONY OF

RICHARD C. FURMAN

ON BEHALF OF

THE SIERRA CLUB, INC.

SAVE OUR CREEKS

FLORIDA WILDLIFE FEDERATION

ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA

ELLEN PETERSON

MARCH 16, 2007

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Table of Exhibits

I. BACKGROUND AND WORK EXPERIENCE

Q. Please State Your Name and Address for the Record.

A: My name is Richard C. Furman. My address is 10404 S.W. 128 Terrace, Perrine, Florida 33176.

Q: What Is Your Occupation?

A: I am a retired consulting engineer, and I volunteer my time to advise utilities, government agencies, environmental groups and the public about the potential benefits of using coal gasification technologies. I have testified in previous permit hearings for proposed coal plants concerning emission control technologies, applicable emission regulations and alternative technologies concerning Mercury, NO_x, SO_2, particulate and CO_2 emissions and their associated costs.

Q: How Long Have You Been Retired?

A: Since February 2003.

Q: What Was Your Occupation Before You Retired?

A: During my entire engineering career, I have worked on new energy technologies, alternative fuels for power plants, and pollution control for power plants. Prior to my retirement, I was an independent consulting engineer for 22 years to various utility companies, government agencies, process developers and research organizations on the development, technical feasibility and application of new energy technologies and alternative fuels for power plants.

Q: What Did You Do Before You Were An Independent Consulting Engineer?

A: Prior to my work as a consulting engineer, I managed Florida Power & Light's coal conversion program and fuels research and development program, which included the first conversion of a 400 megawatt (400MW) power plant from oil to a coal-oil mixture to reduce oil consumption after the second oil embargo. Prior to this, I directed the engineering study for the conversion of New England Electric's Brayton Point Power Plant, which was the first major conversion of a power plant from oil to coal after the first oil embargo.

My first engineering job was working for Southern California Edison Company to modify their power plants for two-stage combustion to reduce nitrogen oxide emissions in 1969.

Q: Please Summarize Your Formal Education.

A: I received my B.S. in Chemical Engineering from Worcester Polytechnic Institute in 1969 and a M.S. in Chemical Engineering from Massachusetts Institute of Technology in 1972. I was a researcher at MIT for the book entitled <u>New Energy Technologies</u> by Hottel and Howard. After researching for this book, I decided to do my Master's thesis on coal gasification because of its potential as a future energy source and its environmental benefits. My Master's thesis at MIT was entitled <u>Technical and Economic Evaluation of Coal Gasification Processes</u>. I was also a teaching assistant at MIT for the courses of <u>Principles of Combustion and Air Pollution</u> and <u>Seminar in Air Pollution Control</u>. My resume was attached to my original testimony as Exhibit RCF-1.

Q: How Does Your Education and Experience Prepare You to Provide Expert Testimony in this Case?

A: Both my education and work have required an in-depth understanding of past, present and new forms of energy technologies that can be used for power plants. My education and work experiences also involved an in-depth understanding of all the various fuels for power plants including the different types of coals, fuel oils, natural gas, petroleum coke, synthesis gas, biomass, and refinery wastes. My graduate education and subsequent work experiences have provided me with a detailed understanding of the techniques and costs for controlling power plant pollution including mercury, NO_x, SO_2, CO, particulate matter and CO_2 emissions. My prior work for 3 major electric utility companies allowed me to make use of this knowledge to help develop and utilize new fuels and emission control technologies for power plants. My current volunteer experience allows me to keep informed about the latest developments in new energy technologies, coal gasification technologies, fuels for power plants, techniques for controlling power plant emissions, costs associated with the application of these technologies for power plants and the development of new technologies that may be applicable to power plants.

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Sierra Club, Inc., Florida Wildlife Federation (FWF), Save Our Creeks (SOC), the Environmental Confederation of Southwest Florida (ECOSWF) and Ellen Peterson.

II. SUMMARY OF TESTIMONY

Q: What Is Your Expert Opinion About the Testimonies Submitted by FPL?

A: I was not allowed sufficient time for the preparation of my testimony and to review and prepare responses to the Petitioner's testimonies. I did not have sufficient time to review the testimony of Mr. Hicks and others.

It is essential to be able to determine the **wide differences** that exist between the Black & Veatch Report that was prepared for FPL, Clean Coal Technology Selection Study, Final Report, dated January, 2007, submitted as Document No. DNH-2 and the U.S. Department of Energy Study, Federal IGCC

R&D: Coal's Pathway to the Future, by Juli Klara, presented at GTC, Oct. 4, 2006 which I used for my Exhibits RCF-5 and RCF-7. Since the conclusions reached by each of these studies are so dramatically different **it is necessary to evaluate the various input assumptions** that were used for both of these studies to determine what created the opposite conclusions. This evaluation would be prudent before a final decision is made for this FGPP plant.

I have shown that coal gasification offers opportunities to significantly reduce emissions and provide lower cost electricity for the future. I would like you to consider all of these facts before you make a decision on the proposed FGPP plant that will increase the cost of electricity, cause increased health problems and damage the environment.

My supplemental testimony shows that Mr. Jenkins has selectively picked information that does not accurately represent the current status of gasification technology and commercial IGCC plants.

Mr. Jenkins has presented a very narrow view of gasification technology and IGCC plants by specifying only four coal-based IGCC plants. In my original testimony, Exhibits RCF-16 and RCF-17, I presented the widely accepted data by the Department of Energy that the 2004 World Survey of Gasification showed 117 operating gasification plants with 385 gasifiers and that there are 14 commercially operating IGCC plants.

The commercial IGCC plants that have been operating for more than 10 years are about 300 MW each and consist of a single gasifier and a single gas turbine. To provide larger size plants multiple units of this same 300 MW size are already in commercial use. The Salux and ISAB Energy plants in Italy as described in Exhibit RCF-17 are multiple unit IGCC plants of more than 500

MW and operating at greater than 90% availability. The use of multiple units has already been demonstrated successfully. Therefore any size IGCC plant can now be built as shown in my Exhibit RCF-20. This exhibit shows the 1200 MW IGCC plant that has been announced by Nuon, in The Netherlands. This utility has been operating a 300 MW IGCC unit for more than 10 years with coal and biomass. Nuon's new 1200 MW plant will have the flexibility to use coal, biomass and natural gas and will consist of four 300 MW units. Therefore scale-up of equipment is not required. Nuon will be using the same size of equipment that they have been operating for more than 10 years. This significantly reduces any risks. The Hunton Energy Group plans to build a 1200 MW IGCC plant in Texas that will use petroleum coke and consist of four 300MW units.

The standard industry practice is to use multiple gas turbine units to achieve the large plant sizes required. As an example the new FPL West County Energy Center in Palm Beach County will consist of 6 gas turbines, 6 HRSG and 2 steam turbines to provide 2400 MW of capacity. The proposed capacity of 1960 MW for the FGPP plant can be matched approximately with three 630 MW IGCC units for a total of 1890 MW which would consist of 6 gas turbines. These multiple unit IGCC plants improve system reliability, increase efficiencies and provide fuel diversity.

Tampa Electric Company's (TECO) IGCC unit has been operating for more than 10 years. Its primary purpose was to demonstrate the technical and economic feasibility of an IGCC unit at full commercial scale. TECO's IGCC unit is now the lowest incremental cost unit and dispatched first. Mr. Jenkins testimony does not completely or accurately represent this very successful commercial demonstration of an IGCC plant.

The development of Super-Critical Pulverized Coal (SCPC) plants had a more difficult track record and took longer to work out the "bugs." My concern is that FPL is proposing to use the **more advanced** technology of Ultra Super-critical Pulverized Coal (USPC) and there are no other USPC plants operating in the U.S. Supplemental Exhibit RCF-27 shows that there are only 4 USPC plants to be built in the U.S. compared to 32 IGCC plants. The source of this Exhibit is a DOE Report, Tracking New Coal-Fired Power Plants, dated Jan. 24, 2007, page 24, available at: http://www.netl.doe.gov/coal/refshelf/ncp.pdf

If the track record of these new USPC plants follows that of SCPC plants then the additional costs for the proposed FGPP plant will be much greater than the IGCC alternative. If the future costs of additional emission controls or purchase of emissions credits are also factored into the FGPP plant, then the result will be higher electric rates. These appear to be excessive and unnecessary risks associated with the present design of the FGPP plant.

Mr. Jenkins would have one believe that by operating with syngas, there is additional rotational stress that has negative impacts on gas turbine reliability. This is not the case, and his testimony is misleading. The control system protects the gas turbine from operating at a condition where the rotor torque limit might be exceeded and impact on its reliability.

Mr. Jenkins is correct in saying that there were issues with rotor reliability at Polk and Wabash IGCC plants, but what he didn't say was that these issues also were faced by owners of the GE Frame 7F all over the world, regardless of the fuel being used. Supplemental Exhibit RCF-28 shows the power output vs. ambient temperature curves for the GE Frame 7FA and 7FB models.

By inferring that these issues were related to the use of syngas, and not mentioning that GE had a generic rotor design problem, he misrepresented the data and detracted seriously from the credibility of his "expert" testimony. Similarly, by not pointing out that most of the unavailability experienced by the operating IGCC plants was due to problems with the power block (i.e. conventional combined cycle equipment) and not to the gasification block, Jenkins' was not being forthright in his testimony.

The operation of IGCC units with backup fuel is as reliable as Natural Gas Combined Cycle (NGCC) units. Reliability for IGCC plants with backup fuel is in the mid 90%. Supplemental Exhibit RCF-29 is a recent Gas Turbine World article titled, <u>Refinery IGCC Plants are Exceeding 90% Capacity Factor after 3 Years</u>, dated Jan.-Feb. 2006, by Harry Jaeger. This article shows that the availabilities of three IGCC plants are 93%, 90% and 94% availability. These availabilities are without a spare gasifier and without a backup fuel.

CO_2 capture is being done commercially at many coal gasification plants around the world on coal-derived syngas. Examples of this in the U.S are the Great Plains Synfuels Plant in North Dakota, the Coffeyville Fertilizer Plant in Kansas and the Eastman Chemical Plant in Tennessee. In my original testimony on pages 25-27, I presented information on the Great Plains Synfuels Plant. Exhibit RCF-22 shows this plant. Carbon dioxide capture, transportation and sequestration have been operating commercially since 2000 at the Great Plains Synfuels Plant. In 2000, the Great Plains Synfuels Plant added a CO_2 recovery process to capture the CO_2. It transports the CO_2 by pipeline 205 miles, as shown in Exhibit RCF-23, to the Weyburn oil fields where it is used for enhanced oil recovery (EOR).

This demonstrates that CO_2 capture is being done on a commercial basis from coal gasification plants. CO_2 capture is not being done presently on any IGCC plants because the process of generating power does not require it to be removed and CO_2 regulations have not been promulgated yet. The other coal gasification applications have demonstrated that CO_2 capture is commercially available.

III. SCHEDULE ERRORS FOR SUBMITTAL OF TESTIMONIES

Q. Were you allowed sufficient time for the preparation of your testimony and to review and prepare responses to the Petitioner's testimonies? If no, please explain.

A: No. The Order Establishing Procedure set forth March 21, 2007, as the date for filing rebuttal testimony and exhibits. I had arranged my schedule to accommodate this limited response time for the large volume of testimony submitted by the petitioner. However, due to a scrivener's error, the Order incorrectly designated that **all** parties may file rebuttal testimony and exhibits, rather than designating that only the Applicant has the ability to do so, which was the intent. After my testimony was submitted on March 7th the corrective order was established that would only allow until March 16 to submit supplemental testimony or corrected testimony by the interveners. The limited amount of time that I have been given to prepare responses to the Petitioner's testimony did not allow me sufficient time to prepare responses to all of the testimonies. Therefore this supplemental testimony is limited by the schedule that was imposed.

IV. COMMENTS ON THE TESTIMONY OF STEVE JENKINS

Q. Where you able to review the testimony of Steve Jenkins?

A: Yes.

Q. Do you think that it accurately represents the current status of IGCC technology?

A. No.

Q: On Page 7, line 8 of Mr. Jenkins testimony the following Question was asked: "Please describe some of the currently existing IGCC plants in the United States and around the world." And Mr. Jenkins replied: "There are four coal-based IGCC plants in operation worldwide." Does this accurately represent the current commercial status of IGCC Plants? If no, please explain.

A: No. Mr. Jenkins has presented a very narrow view of gasification technology and IGCC plants by specifying only four coal-based IGCC plants. In my testimony, Exhibits RCF-16 and RCF-17, I presented the widely accepted data by the Department of Energy that the 2004 World Survey of Gasification showed 117 operating gasification plants with 385 gasifiers and that there are 14 commercially operating IGCC plants. The fact that gasifiers are using all different types of coal, petroleum coke, heavy oils, asphalt, refinery residues, biomass, and waste materials on a commercial scale should indicate the wide flexibility of gasification to use all types of liquid and solid fuels. To narrow his answer to only 4 coal-based IGCC plants is a misleading representation of the current state of this technology.

Q: On Page 8, line 3 of Mr. Jenkins testimony the following Question was asked: "What is the largest size IGCC plant that is commercially

available?" and Mr. Jenkins replied "The largest size being commercially available is called the 600 MW net "reference plant."...It will first be very important to prove the coal gasification technology at this larger scale." Does this accurately represent the current commercial status of IGCC Plants? If no, please explain.

A: No. The commercial IGCC plants that have been operating for more than 10 years are about 300 MW each and consist of a single gasifier and a single gas turbine. To provide larger size plants multiple units of this same 300 MW size are already in commercial use. The Salux and ISAB Energy plants in Italy as described in Exhibit RCF-17 are multiple unit IGCC plants of more than 500 MW and operating at greater than 90% availability. The use of multiple units has already been demonstrated successfully. Therefore any size IGCC plant can now be built as shown in my Exhibit RCF-20. This exhibit shows the 1200 MW IGCC plant that has been announced by Nuon, in The Netherlands. This utility has been operating a 300 MW IGCC unit for more than 10 years with coal and biomass. Nuon's new 1200 MW plant will have the flexibility to use coal, biomass and natural gas and will consist of four 300 MW units. Therefore scale-up of equipment is not required. Nuon will be using the same size of equipment that they have been operating for more than 10 years. This significantly reduces any risks. The Hunton Energy Group plans to build a 1200 MW IGCC plant in Texas that will use petroleum coke and consist of four 300MW units.

The standard industry practice is to use multiple gas turbine units to achieve the large plant sizes required. As an example the new FPL West County Energy Center in Palm Beach County will consist of 6 gas turbines, 6

HRSGs and 2 steam turbines to provide 2400 MW of capacity. The proposed capacity of 1960 MW for the FGPP plant can be matched approximately with three 630 MW IGCC units for a total of 1890 MW which would consist of 6 gas turbines, 6 HRSGs and 3 steam turbines. These multiple unit IGCC plants improve system reliability, increase efficiencies and provide fuel diversity.

Q: On Page 8, line 17 of Mr. Jenkins testimony the following Question was asked: "Have the current IGCC facilities been funded by their governments?" and Mr. Jenkins replied "Yes. All four of the operating plants received significant amounts of co-funding from their respective federal governments...In the case of the Polk Power Station, the DOE funded 20-25% of the capital cost". Is this a complete and accurate representation of the commercial viability of IGCC plants? If no, please explain.

A: No. Polk Power Station's IGCC unit has been operating for more than 10 years. Its primary purpose was to demonstrate the technical and economic feasibility of an IGCC unit at full commercial scale. Another objective of this demonstration project was to improve the technology by testing new process steps that increase efficiencies and reduce emissions. Therefore much of the government funding was specifically used to demonstrate these improvements. An example of the type of improvement that was tested at the Polk Plant was hot gas clean-up which is no longer in service. The Polk IGCC unit is now the lowest incremental cost unit and dispatched first. Mr. Jenkins testimony does not completely or accurately represent this very successful commercial demonstration of an IGCC plant.

Q: **On Page 9, line 1 of Mr. Jenkins testimony the following Question was asked: "What has been the track record of these facilities?" and Mr. Jenkins response was: "The initial start-up at all of these plants was very difficult and the overall plant availability for each of these plants was low for the first several years. Since then, many operational problems have been solved, some equipment has been removed or modified, and many of the "bugs" have been worked out." Does this accurately represent the track record of IGCC Plants? Please explain this in relation to the development of other new power plant technologies.**

A: Yes. This statement is true. But it is also true that this track record is typical of new power plant technologies. The development of Super-Critical Pulverized Coal (SCPC) plants had a more difficult track record and took longer to work out the "bugs". My concern is that FPL is proposing to use the more advanced technology of Ultra Super-critical Pulverized Coal (USPC) and there are no other USPC plants operating in the U.S. Supplemental Exhibit RCF-27 shows that there are only 4 USPC plants to be built in the U.S. compared to 32 IGCC plants. The source of this Exhibit is a DOE Report, <u>Tracking New Coal-Fired Power Plants</u>, dated Jan. 24, 2007, page 24, available at <u>http://www.netl.doe.gov/coal/refshelf/ncp.pdf</u> .

If the track record of these new USPC plants follows that of SCPC plants then the additional costs for the proposed FGPP plant will be much greater than the IGCC alternative. If the future costs of additional emission controls or purchase of emissions credits are also factored into the FGPP plant, then the result will be higher electric rates. These appear to be excessive and unnecessary risks associated with the present design of the FGPP plant.

Q: On Page 10, line 5 of Mr. Jenkins testimony the following Question was asked: "Why do IGCC plants have problems with reliability?" and Mr. Jenkins replied: "The four IGCC plants all have single-train gasification islands. Whenever a single train is removed from service due to operational problems, there is no syngas available for combustion in the gas turbines. At that point, unless a backup fuel is used, the power plant must be shut down." Is this an accurate and complete Statement? If no, please explain.

A: No. This statement is true but not complete. If the two conditions occur at the same time, which are no syngas and no backup fuel, then the unit can not operate. However the probability of these two events occuring simultaneously is very small. That is why IGCC plants that have a backup fuel can have 95% availabilities. This is better than the proposed 92% availability that FPL is estimating for their USPC Plant. The 980 MW USPC units consist of a single boiler and a single steam turbine operating at conditions that have not been used before in the U.S. Therefore, a single failure in the boiler or the steam turbine can cause 980MW not to operate. This is not the case with IGCC units because they consist of multiple units. A single failure should only cause the loss of a 300MW unit. If that single failure occurs in the gasification part of the plant then the backup fuel can be used and there will be no significant loss of capacity. This is not the case with the proposed USPC plant. A coal supply interruption, such as a coal strike, can cause the loss of all 1960 MW because no backup fuel is available. The costs of using backup fuels for IGCC units will increase the cost of electricity and therefore needs to be considered. But the cost savings of higher availabilities more than offset these additional fuel costs.

Q: In response to the same question above Mr. Jenkins also stated on page 10, lines 15 - 20: "A reliability issue that is somewhat unique to syngas use relates to high rotor torque. Gas turbines are designed to handle the combustion of natural gas. Since syngas has a much lower heating value, a much greater amount of syngas is required to fully load the gas turbine. ***This additional rotational stress has had negative impacts on syngas-fired gas turbine reliability."*** **Is this a true fact? If no, please explain.**

A: No. Since diluted syngas (i.e. syngas diluted with N_2 for NO_x control) has a heating value of only about 1/8 of natural gas, there is a lot more fuel mass required to reach full operating conditions than with natural gas. This affects the amount of power that the same piece of equipment will generate (proportional to mass flow and other conditions, such as pressure and temperature, at the turbine section inlet). Therefore, at a given ambient temperature, the syngas-fired gas turbine will produce more power than the same machine fired with natural gas.

Supplemental Exhibit RCF-28 shows the power output vs. ambient temperature curves for the GE Frame 7FA and 7FB models. Both the Polk and Wabash IGCC units use the earlier Frame 7F gas turbines. The "FA" and the "FB" models are updated versions of these gas turbines. As you can see, the normal performance characteristic of a gas turbine is that the power output increases with lowering ambient temperature. That is the basic physics of any air breathing engine since there is more mass taken in with a given volume at lower temperatures. There are two curves - one for natural gas, and one for diluted syngas.

Superimposed on the performance curves are the 'rotor torque limit curves'. These define the power limit that is imposed on the gas turbine for safe and reliable operation **- regardless of the fuel used**. You can see that the torque limit for the 7FB is slightly higher than that of the 7FA, allowing more power to be generated with the upgraded design.

Since the performance curve (power vs. temp) for the diluted syngas is generally higher than that for natural gas, it crosses the torque limit curve at a higher ambient temperature. That says that the power output is limited to that maximum value (i.e. where it crosses the torque limit curve) at around 85-90F. It is essentially the same limit that is reached in the natural-gas-fired case down around 20F. **This limit placed on the power output of the gas turbine means that it does not run at higher than its maximum design level of power output when burning syngas, as inferred by Mr. Jenkins.** It just means that it reaches its limit at a higher ambient temperature, so that the actual additional IGCC output (dark blue area) is less than it might be if no such rotor torque limit existed. **Mr. Jenkins would have one believe that by operating with syngas, there is additional rotational stress that has negative impacts on gas turbine reliability. This is not the case, and his testimony is misleading.**

At lower ambient temperatures, when the gas turbine might operate above the rotor torque limit, the control system adjusts the operating point of the gas turbine to limit its output. In other words, it is operating at part load (rather than at full load) at ambient temperatures below which the power output curve intersects the rotor torque limit curve. This prevents any overloading of the gas turbine that might otherwise occur - and it is the exact same control whether operating on syngas or natural gas fuel.

The control system, thereby, protects the gas turbine from operating at a condition where the rotor torque limit might be exceeded and impact on its reliability. **Mr. Jenkins is correct in saying that there were issues with rotor reliability at Polk and Wabash IGCC plants, but what he didn't say was that these issues also were faced by owners of the GE Frame 7F all over the world, regardless of the fuel being used.**

By inferring that these issues were related to the use of syngas, and not mentioning that GE had a generic rotor design problem, he misrepresented the data and detracted seriously from the credibility of his "expert" testimony. Similarly, by not pointing out that most of the unavailability experienced by the operating IGCC plants was due to problems with the power block (i.e. conventional combined cycle equipment) and not to the gasification block, Jenkins' was not being forthright in his testimony.

In a recent presentation at the European Gasification Conference in Barcelona, an executive of the utility that operates the Puertollano IGCC plant in Spain showed the breakdown of causes of their availability issues. A large majority of these issues had to do with the gas turbine (in this case a Siemens advanced-design model) and not the gasification island. The source for this information is: <u>Puertollano IGCC Plant. Present Position and Future Competitiveness</u>, by Casero and Garcia-Pena of Elcogas S.A., presented at the 7th European Gasification Conference, Barcelona, Spain, April 25-27, 2006, pages 4&5.

Mr. Jenkins referred again to the poor availability performance of the Puertollano facility, (Mr. Jenkins testimony, page 10, line3) without mentioning that most of the problems were gas turbine related, and that the same problems were experienced by other owners of the same design gas turbine operating on natural gas, and consequently, Mr. Jenkins seriously reduced the credibility of his testimony.

Q: In response to the same question above Mr. Jenkins also stated on page 11, lines 3 - 6: "Some of the successful gasifiers also use refinery bottoms, like asphalt, as a feedstock. Such liquid feedstocks require little handling and preparation, versus the coal handling and coal grinding systems required in a coal-based IGCC plant." Do you agree with this statement? If no, please explain.

A: No. Mr. Jenkins should have also pointed out that coal-slurry-fed gasifiers (such as GE and ConocoPhillips) operate on a feedstock that is very much like a liquid feedstock in that powdered coal is first mixed with water to form a pumpable, liquid-like slurry. The GE and ConocoPhillips gasifiers, whether using coal-slurry or liquid fuels are proven to be highly reliable in numerous commercial installations around the world.

Q: On Page 15, line 3 of Mr. Jenkins testimony the following Question was asked: "What are some of your concerns with the use of IGCC technology at the site?" and Mr. Jenkins responded: "First, I would be concerned with the potential for reliability problems. FGPP is being designed for 92% reliability, which is commercially available and proven with SCPC technology. As noted previously, such high reliability levels have not yet been demonstrated by existing IGCC power plants, and it will be six to

eight years before the presently planned IGCC plants are able to prove whether the intended design enhancements can provide for improved reliability." Do you agree with these statements? If no, please explain.

A: No. As previously discussed in this supplemental testimony the operation of IGCC units with backup fuel are as reliable as Natural Gas Combined Cycle (NGCC) units. Reliability for IGCC plants with backup fuel is in the mid 90%. Supplemental Exhibit RCF-29 is a recent Gas Turbine World article titled, Refinery IGCC Plants are Exceeding 90% Capacity Factor after 3 Years, dated Jan.-Feb. 2006, by Harry Jaeger. This article shows that the availabilities of these three IGCC plants are 93%, 90% and 94% availability. These availabilities are without a spare gasifier and without a backup fuel. These IGCC plants were built using non-recourse project financing provided by over 60 banks, U.S. IPP developers and other lending institutions. They show that IGCC can be a commercially bankable technology.

Q: On page 13, line 12 Mr. Jenkins was asked "When do you think IGCC will be commercially available? and on page 13, line 21 thru page 14, line 8 Mr. Jenkins replied: "If IGCC technology were to be selected for this project, FPL would likely use the largest size plant available, in order to take advantage of economies of scale, just as it has already done in choosing large 980 MW (net) USCPC units. For IGCC, the closest match to meet the 1,960 MW (net) value would be to use a 3x3~1 configuration such as the one referenced in the study jointly conducted by FPL and Black & Veatch. This study is noted as Document No. DNH-2 in the testimony provided by Mr. Hicks of FPL. However, as I noted previously, the largest size IGCC facility that is being offered by the IGCC technology suppliers is the 600

MW (net) reference plant. ***Therefore, a non-standard 3x3~1 configuration, if commercially available, would take even longer to be designed and constructed."*** **Is this last statement by Mr. Jenkins correct? If no, please explain.**

A: No. This last statement is not true. Three of the "reference design" units of 630 MW each could provide 1890 MW using the standard configuration of 2 gas turbines and one steam turbine for each 630 MW unit. This would not require the non-standard configuration that Mr. Jenkins indicated that would take longer to design and construct.

Q: On page 17, line 6 Mr. Jenkins states: "Two of the IGCC plants being planned at this time for operation in the 2011 to 2012 timeframe have noted in their air permit applications the potential for over 60 startup and shutdown events per year, far more than what is normal for PC units." Is this typical of IGCC plants? If no, please explain.

A: No. This is the worst case scenario that is required for permitting application and does not represent normal operating experience.

Q: On page 22, line 3 Mr. Jenkins states: "When a PC power plant starts up, the boiler is fired with coal at a very low throughput, and then it gradually ramps up to a higher throughput." Is this statement true? If no, please explain.

A: No. PC plants start up on oil, not coal, and fire coal after they are on line.

Q: On page 22, line10 Mr. Jenkins states: "During the time a plant is starting up, coal is being consumed without any power generation, until steam conditions are right for sending it to the steam turbine." Is this statement true? If no, please explain.

A: No. Coal is not used to warm-up a PC boiler or a gasifier.

Q: On page 22, line 21 Mr. Jenkins states: "IGCC units have a different start-up profile. As noted previously, a cold start-up on an IGCC power plant can take several days. During this time, large amounts of coal can be consumed in the gasification process while the emission control systems are being started up. Clean or partially cleaned syngas is flared. Emissions from the flare can be substantial, depending on the state of operation of the emission control systems and the total time of flaring. Combining these technical issues with a somewhat lower reliability of IGCC versus PC technology, an IGCC plant could actually produce more emissions on an annual basis than a PC unit, even though it may have a lower emission rate on a IbNWh or pounds per million BTUs of heat input basis." Are these statements true? If not, please explain.

A: No. Gasifiers are preheated with natural gas or propane. Gasifiers are not preheated with coal. The flaring only occurs immediately after the gasifier light off for a short duration. It is true that these emissions are higher than normal operation, but they occur for short durations (minutes), not the days stated by Mr. Jenkins.

Q: On page 23, line 8 Mr. Jenkins was asked the Question: "Based on the technology today, do you believe that the emissions would be better for an IGCC facility versus the proposed FPL power plant?" and Mr. Jenkins reply consisted of the statement: "We saw that the emission rates for the IGCC units could actually be increased by an average of 38%, *if all of the potential startup and shutdown emissions are accounted for*." Does this

accurately represent the operation of current IGCC plants? If no, please explain.

A: No. This analysis is based upon the sum of all of the worst case assumptions that could have been conceived. This does not accurately represent the operation of current IGCC plants including their normal startup and shutdown procedures. The last two sentences of Mr. Jenkins answer to this question are true when he stated: "The air permit applications were written in a way so as not to constrain the units' operation, **so that the number of start-up and shutdown cycles was maximized. For an actual comparison, each unit's characteristics would have to be analyzed to determine the overall impact of start-ups and shutdowns."**

Q: On page 24, line 16 Mr. Jenkins was asked: "What changes are needed to make an IGCC plant CO_2 capture ready?" and part of Mr. Jenkins response was: "The IGCC plant design must account for the addition of this water shift reactor and to have a proper place to route this low pressure steam." Is this statement true and is it a significant modification?

A: This statement is true but it is not a significant modification. This additional steam will be used for other processing applications in the IGCC plant.

Q: In response to the same question Mr. Jenkins also stated: "Then there must be room for the addition of a very large CO_2 capture/removal system. While the acid gas removal systems typically used for H2S removal can also be used to absorb some of the CO_2, they are much more selective for the H2S. This means that it is much more difficult to remove the CO_2 than the H2S from the syngas. The H2S removal system is much too small to also remove a large portion of the CO_2. It must be able to be scaled up

considerably, with much additional equipment required. The CO_2 removal system requires a significant amount of high pressure steam to strip (remove) the CO_2 from the solvent, so that it can be concentrated. Therefore, the steam turbine must be designed from day one with steam extractions at the right temperatures and pressures for CO_2 stripping." Is this the preferred method to add CO_2 capture to an existing IGCC plant? If no, please explain.

A: No. The preferred method would be to add a "sweet shift" downstream of the original Acid Gas Removal (AGR) process and then to add a second absorber for the CO_2 removal. This method would make use of the existing equipment and require much less new equipment. This would significantly reduce the capital costs for CO_2 capture. The operating costs can also be reduced because low pressure steam is used for stripping not the high pressure steam that Mr. Jenkins stated for stripping.

Q: In response to the same question Mr. Jenkins also stated: "Once the CO_2 is removed from the syngas, a hydrogen-rich syngas stream remains. While gas turbines have the ability to burn syngas and other fuels that contain some hydrogen, gas turbines for the combustion of concentrated hydrogen streams are *not yet commercially available at large scale.*" Is this statement true? If no, please explain.

A: No. Industrial gas turbines have been integrated into refineries, petrochemical plants and chemical manufacturing plants that operate on high hydrogen content fuels routinely.

Q: On page 26, line 11 Mr. Jenkins was asked: "Have CO_2 capture technologies been applied to IGCC?" and Mr. Jenkins responded: "Yes,

but only on a test basis." On page 26, line 13 Mr. Jenkins was asked: "Are EPRI and the DOE funding R&D on CO_2 capture technologies?" and Mr. Jenkins responded: "Yes. A significant amount of design development is underway, in order to qualify and quantify the modifications described previously. ***CO_2 capture for IGCC is not yet a commercially available technology."*** **Are these accurate statements of the current commercial status of CO_2 capture from gasification plants? If no, please explain.**

A: No. CO_2 capture is being done commercially at many coal gasification plants around the world on coal-derived syngas. Examples of this in the U.S are the Great Plains Synfuels Plant in North Dakota, the Coffeyville Fertilizer Plant in Kansas and the Eastman Chemical Plant in Tennessee. In my original testimony on pages 25-27, I presented information on the Great Plains Synfuels Plant. Exhibit RCF-22 shows this plant. Carbon dioxide capture, transportation and sequestration have been operating commercially since 2000 at the Great Plains Synfuels Plant. In 2000, the Great Plains Synfuels Plant added a CO_2 recovery process to capture the CO_2. It transports the CO_2 by pipeline 205 miles, as shown in Exhibit RCF-23, to the Weyburn oil fields where it is used for enhanced oil recovery (EOR). This demonstrates that CO_2 capture is being done on a commercial basis from coal gasification plants. CO_2 capture is not being done presently on any IGCC plants because the process of generating power does not require it to be removed and CO_2 regulations have not been promulgated yet. The other coal gasification applications have demonstrated that CO_2 capture is commercially available.

Q: On page 28, line 1 Mr. Jenkins was asked: "Can you say that IGCC is 'CO_2 capture ready' today?" and Mr. Jenkins response was: ***"It is not. Once the***

R&D is completed over the next decade, as described previously, IGCC is expected to be CO_2 capture ready." **Is this an accurate statement? If no, please explain.**

A: No. The answer to my previous question clearly shows that CO_2 capture is being done on a commercial basis for syngas produced from coal gasification plants. The only difference is the final use of the syngas. It can be used for power generation in a combined- cycle IGCC plant, as a fuel to produce synthetic natural gas (SNG), and as a raw material to produce chemicals and fertilizers. The engineering companies and equipment suppliers are ready to provide CO_2 capture for commercial IGCC plants. They do not need a decade of R&D to build what is already commercially operating.

V. COMMENTS ON THE TESTIMONY OF DAVID HICKS

Q: Where you able to review the testimony of David Hicks?

A: No. I did not have sufficient time to review the testimony of Mr. Hicks. It is essential to be able to determine the **wide differences** that exist between the Black & Veatch Report that was prepared for FPL, <u>Clean Coal Technology Selection Study, Final Report</u>, dated January, 2007, submitted as Document No. DNH-2 and the U.S. Department of Energy Study, <u>Federal IGCC R&D: Coal's Pathway to the Future, by Juli Klara,</u> presented at GTC, Oct. 4, 2006 which I used for my Exhibits RCF-5 and RCF-7. Since the conclusions reached by each of these studies are so dramatically different it is necessary to evaluate the various input assumptions that were used for both of these studies to determine what created the opposite conclusions. This evaluation would be prudent before a final decision is made for this FGPP plant.

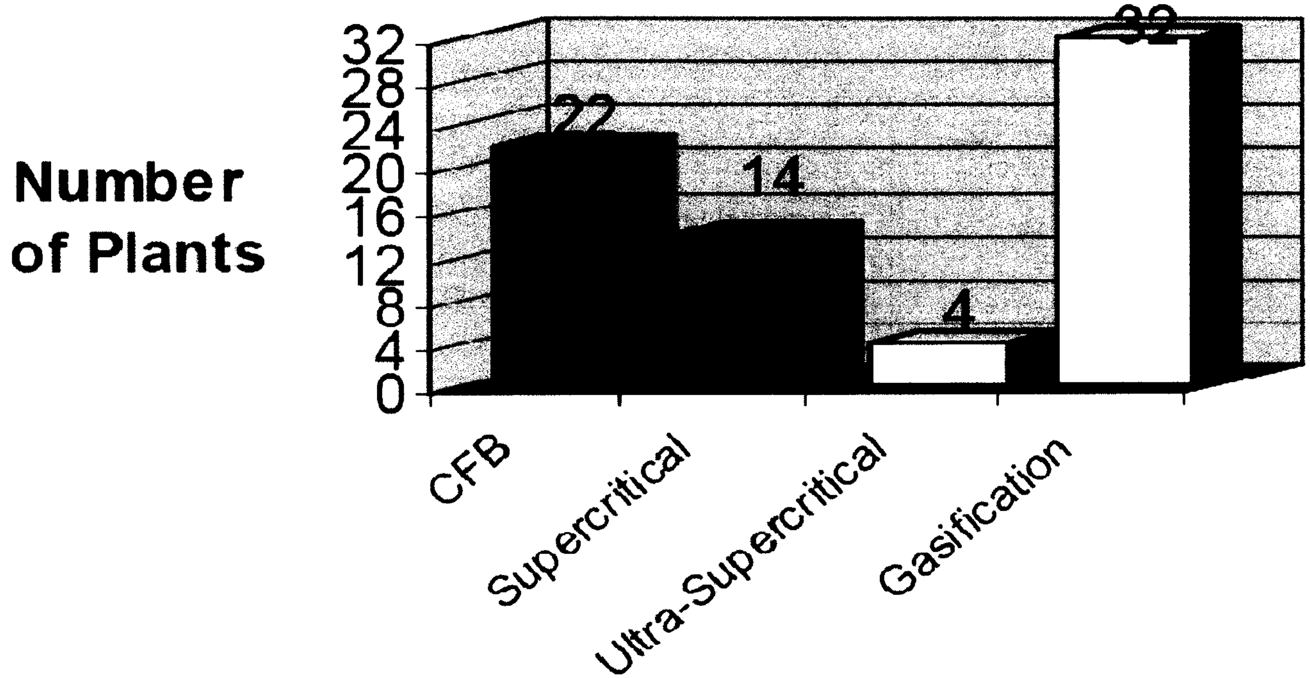
Q: Does this conclude your Supplemental Testimony?

A: Yes. I have prepared as much Supplemental Testimony as the schedule would allow me to prepare. More time is needed to do a more complete evaluation.

Tracking New Coal-Fired Power Plants

Coal's Resurgence in Electric Power Generation

Advanced Technologies



NETL Contacts: Scott Klara, klara@netl.doe.gov
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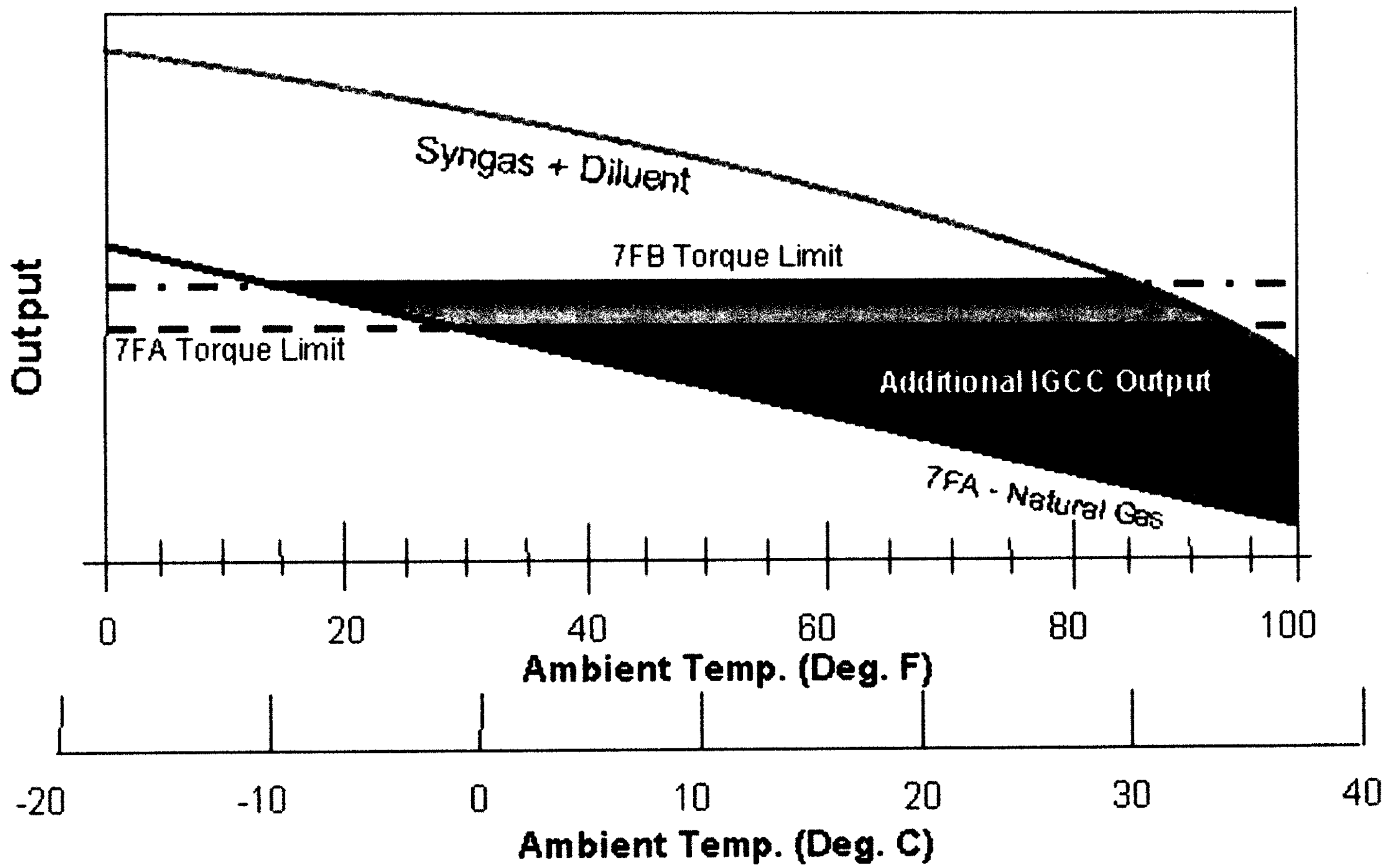
IGCC Output Enhancement

Gas Turbine Output vs. Ambient Temperature



Source: <u>IGCC – Clean Power Generation Alternative For Solid Fuels</u>, by Shilling and Lee, GE Power Systems, presented at PowerGen Asia 2003, page 8, figure 16.

Refinery IGCC plants are exceeding 90% capacity factor after 3 years

Docket No. 070098-EI
Refinery IGCC Plants are Exceeding 90% Capacity
Supplemental Exhibit RCF-29, Page 1 of 7

By Harry Jaeger

Steep learning curves for commercial IGCC plants in Italy show annual capacity factors of 55-60% in the first year of service and improvement to over 90% after the third year.

EniPower is commissioning a 250 MW IGCC plant that will burn syngas produced by gasification of residues at an adjacent Eni Sannazzaro refinery in north central Italy.

Based on commercial experience with earlier plants, project engineers predict the annual capacity factor (measure of profitability) of the Sannazzaro plant should match if not outperform them, especially in the critical early years. Specifically:

☐ **ISAB Energy.** Asphalt-based 520 MW plant built by Ansaldo Energia went from a capacity factor of 61% in 2000, first year of commercial operation on syngas, to 93% in 2004.

☐ **Sarlux Saras.** Residues-based 545 MW plant went from a capacity factor of 55% in 2001, first year of commercial operation on syngas, to 90% in 2004.

☐ **Api Energy.** Residues-based 280 MW plant went from a capacity factor of 66% in 2001, first year of commercial operation on syngas, to 94% in 2004.

The Eni Sannazzaro IGCC plant, nominally rated at 250 MW net ouput, is designed around a multi-shaft 1 x 1 Ansaldo manufactured Siemens V94.2K combined cycle module and Shell Global Solutions gasification process.

The combined cycle unit is located at EniPower's 1050 MW station in Ferrera Erbognone along with two 400 MW natural gas-fired Ansaldo V94.3A.2 combined cycle (multi-shaft 1x1 configurations) plants.

Ansaldo Energia re-designed and tested the original Siemens burner design in two different test programs, at Ansaldo's combustion center and the Enel Laboratories R&D center in Italy.

Startup date

The IGCC combined cycle has been operating on natural gas while the gasification system is undergoing commissioning and testing within the refinery battery limits.

The gas turbine recently began commissioning and was expected to begin commercial operation on syngas in mid-2006 selling electricity into the national grid.

The gasification system also will export superheated steam and hydrogen within the refinery.

Originally, the switchover to syngas operation was to take place by the end of 2005. However, an apparent delay in commissioning, along with other refinery modifications, pushed the date off. The actual switchover is to take place in March 2006.

Shell's gasification process has been widely used for industrial applications worldwide; eight coal gasification units are under construction in China alone.

It was selected for the coal-based IGCC demo plant at the Nuon Buggenum power station, The Netherlands, which has been operating for about 12 years. Also for the commercial Pernis refinery IGCC project in The Netherlands that started operations in 1997.

Shell gasifier trains

At the Sannazzaro plant, two 50% oxygen-blown gasifiers will process about 600 tons a day of refinery residues from the Eni Refinery (formerly Agip Petroli).

According to project engineers, Eni chose the Shell gasification process in the interest of achieving higher net plant efficiencies for the intended cogeneration of electricity and steam.

Unlike the Texaco quench-type gasifiers (now GE Energy) used by the other IGCC plants in Italy, the Shell gasifiers are fitted with a heat recovery unit that produces high pressure (84 barg) superheated steam for use in the refinery.

Following heat recovery, the syngas goes through a catalytic hydrolysis unit where COS and HCN are converted to H_2S and NH_3, respectively.

After this, the syngas is washed in a water-spray column, to absorb the ammonia, and the H_2S is then removed in the acid gas removal unit using a chemical solvent absorption process (MDEA-Dow).

Resultant hydrogen sulfide-rich waste gas is sent to a Claus sulfur recovery unit at the refinery to produce a solid sulfur product.

Following acid gas removal, the desulfurized syngas is forwarded to a hydrogen removal and recovery unit that produces pure hydrogen which the refinery uses to produce cleaner fuels.

Co-firing option

Final composition of the syngas, and, therefore its heating value and Wobbe index, will vary depending upon the amount of hydrogen off-take for refinery use.

When the ratio of hydrogen to carbon monoxide is too low (depending on gas turbine combustion system design specs) up to about 10% of natural gas fuel can be added for operation in a co-firing mode.

The syngas modified V94.2K gas turbine is equipped with a dual fuel combustor to operate on natural gas alone as a backup fuel when the gasifier is shut down for scheduled maintenance or service.

Although a Siemens design, the gas turbine was built by Ansaldo (under license) and equipped with its own designed and patented burners.

The "K" designation indicates the addition of one compressor stage to meet requirements of operating with syngas with no (or only partial) integration of the air separation unit.

Ansaldo Energia notes that it performed all of the combustion and fuel system modifications needed to burn and operate on the syngas fuel.

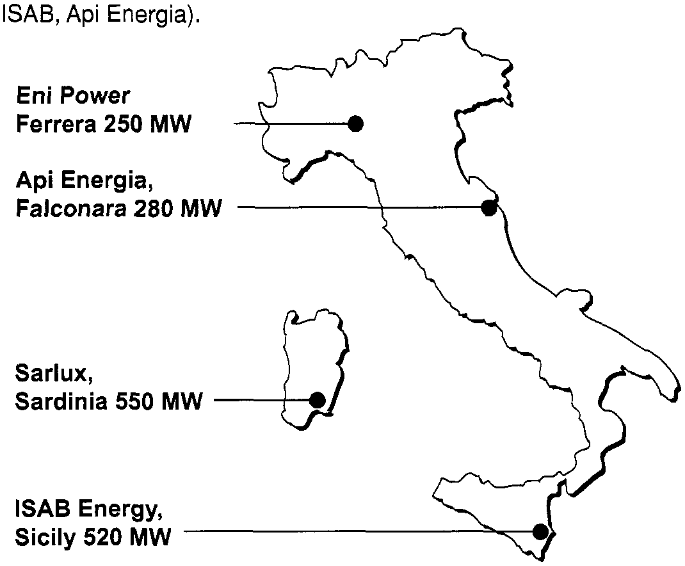
For NOx control purposes, to meet a local 25 ppm environmental limit, dilution steam from the combined cycle's heat recovery steam generator is injected into the syngas before it is fed to the gas turbine.

At an H2 to CO ratio of approximately 1 to 1, and with water vapor comprising about 35% of the gas by volume, the as-delivered lower heating value of the fuel gas is on the order of 175 Btu/scf.

Europe forging ahead

Although many utilities and state regulatory commissions in the U.S. regard IGCC as "emerging" technology, Europe has already acquired a solid base of commercial IGCC design and operating experience (lessons learned) for future projects.

IGCC projects. Refineries are generating electric power, steam and hydrogen from excess low-grade residues. Developed as joint ventures with non-recourse project financing (US$3.1 billion for Sarlux, ISAB, Api Energia).



Since 1995, about 2500 MW of IGCC capacity using heavy petroleum residues in a refinery environment has been installed worldwide.

Italy, with IPP partners from the U.S., has commissioned four refinery-based IGCC plants for commercial operation since 2000 with an installed generating capacity of about 1600 MW.

Two of those plants, rated over 500 MW each, use gasification technology supplied by Texaco (now GE Energy) and were built by EPC teams that included Snamprogetti and Foster Wheeler Italiana of Milan.

Commercial IGCC plants

First of the large Italian IGCC plants, owned and operated by ISAB Energy (51% Erg Petroli and 49% Mission Energy), came on-line in 2000. It is located at the Erg refinery in Priolo, Sicily.

The multi-shaft combined cycle power block, net rated at 520 MW without deducting for gasification auxiliary loads such as the air separation unit, is built around two Ansaldo Siemens V94.2K gas turbines.

Sarlux, the second Italian plant rated at 550 MW, is said to be the largest IGCC plant in the world. It is located at the Saras Oil Refinery, on the island of Sardinia, which supplies the heavy residue feedstock for gasification.

Air Liquide provides oxygen and nitrogen to each of those facilities on an "over the fence" sales basis.

Sarlux started commercial syngas operation in January 2001. It was built by Snamprogetti, Turbotechnica (Nuovo Pignone) and GE Power Systems under ownership of a joint venture between Enron and Saras.

It contains three 184 MW STAG 109E GE/Nuovo Pignone single-shaft combined cycle units.

Output power is sold into the local grid, under a 20-year long term power purchase agreement with Enel.

The plant also supplies the Saras refinery with 200 tons per hour process steam and 1.4 million scf per hour of hydrogen feedstock.

The third plant, owned by Api Energia, is located at the Ancona refinery on the Adriatic coast and entered commercial operation in April 2001.

It was developed as a joint venture project by Anonima Petroli Italiana (51% stake), ABB (25%) and Texaco (24%), and is now 100% owned by Api.

The 280 MW combined cycle power block in this case is built around a syngas modified GT13E2 gas turbine.

Plant design features

Close examination of the ISAB and Sarlux plants reveals subtle design differences in plant configuration that were in large part dictated by plant owner and operations considerations.

Both plants use Texaco (now GE Energy) oxygen-blown quench gasification technology to convert heavy residual oil feedstock to syngas: two gasification trains operating at 70 bar for ISAB versus three, running at only 40 bar, for Sarlux.

Neither has a spare gasifier installed, so that gasifier capacity effectively matches combined cycle requirements. Each gas turbine is fed by a single gasifier. In both cases the gasification process takes place at around 1400°C (2552°F).

However, they do have different sulfur removal systems: a "hybrid" MDEA-Dow Chemical system for ISAB and a "physical" Selexol-UOP system at Sarlux.

Perhaps this has something to do with the different sulfur recovery and tail-gas treatment (H2S to elemental sulfur) methods used at the two plants.

At the ISAB plant the tail gas is treated and incinerated, while at Sarlux it is compressed and recycled back to the Selexol unit. Cleaned syngas in both cases contains about 30 ppm sulfur.

In the case of the ISAB plant, the clean syngas is sent to an expander, where the higher pressure is recovered to produce about 5 MW of additional power.

Syngas treatment

At Sarlux the syngas goes to a UOP hydrogen removal and recovery unit which includes a membrane section and a pressure swing absorption (PSA) section to produce pure hydrogen (over 99% vol) for use within the refinery.

Both plants "moisturize" the syngas in saturator units so that it ends up containing on the order of 35-40% by volume water vapor, before being forwarded to the gas turbines.

This steam dilution has the effect of lowering combustion flame temperature, and thereby NOx production, and also adds a bit of a power boost for the gas turbines.

The fuel gas delivered at around 400°F temperature has an LHV heating value on the order of 165 Btu/scf.

Combined cycle modules

At ISAB the combined cycle is a 2 x 1 design comprised of two Ansaldo Siemens V94.2K gas turbine generators, two HRSGs with duct firing capability, and one condensing steam turbine generator.

For Sarlux, there are three separate 1 x 1 single-shaft GE STAG 109E units, each including one Frame 9001E gas turbine, double-ended generator, condensing steam turbine and HRSG.

Although details are not available from Snamprogetti, they report that the EPC contract values for the two plants "do not differ substantially" so they can be assumed to cost about the same on a $ per kW basis.

Similar start-up hiccups

Also, according to Snamprogetti engineers, the ISAB and Sarlux IGCC plants went through similar commissioning, startup and performance improvement experiences.

There were no problems or delays during initial startup testing and commissioning on backup fuel oil systems. However, integrated IGCC commissioning and startup testing took 10-12 months in each case.

Once in service, both plants also experienced significant operating problems that were complicated by the number of technologies and individual systems involved. These were the first large scale 500 MW-plus IGCC projects commissioned.

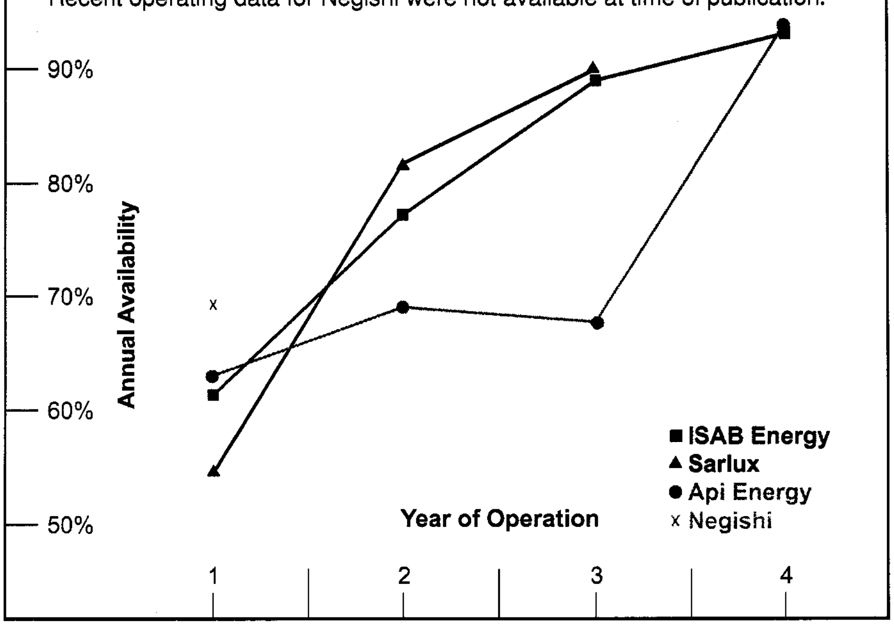
During the first year, after the start of commercial operations, the annual capacity factor on syngas at ISAB was down around 61%, and only around 55% for Sarlux.

Even taking into account plant operation on backup fuel oil, the annual capacity factor came to only 75% and 79% respectively that first year.

ISAB operating issues

Problems at ISAB reportedly had to do with severe corrosion in soot water and gray water circuits, syngas expander reliability, gasifier refractory hot spots, and gas turbine combustor

Commercial IGCC availabilty. ISAB Energy went from 61% to 93% in four years, Sarlux from 55% to 90% in three years and Api Energy from 63% to 94% in four years. Nippon Refining plant in Negishi operated at 69% availability on syngas in its first year of operation. Excludes operation on backup fuel. Recent operating data for Negishi were not available at time of publication.



Source: EPRI, Snamprogetti / Eni, ERG

deposits.

Project engineers note that the asphaltines design feedstock was the heaviest oil feed to be gasified at that time.

Gas turbine deposits, primarily of nickel alloy, were apparently caused by the reaction of CO in the fuel with nickel in combustion system components.

Detailed investigation traced the cause of the deposition to the disassociation of a single contaminant, Nickel Carbonyl (Ni CO4).

There was also an issue with higher than expected ratio of H2 to CO in the syngas, especially with light feedstock, that caused combustion problems.

Initially, Ansaldo and Siemens treated this as an out-of-specs fuel condition and restricted the use of syngas in the gas turbines.

Adjusting gasifier operating temperature and reducing the steam-to-oil feed ratio in the gasifiers solved the problem, but compromised gasifier performance.

Ultimately, Ansaldo and Siemens performed the necessary combustion testing to demonstrate the capability to handle the higher syngas hydrogen levels, resolving the issue and allowing the gasifiers to run at their design operating conditions.

Sarlux operating issues

The first year of operation was marked by a persistent problem of soot carryover in the syngas, especially during plant transients, such as load changes during operation.

This was resolved by modifying gasifier and syngas scrubber operating procedures.

There was also a carryover issue due to the recycling of a small amount of water containing Selexol solvent. Eliminating the recycle greatly improved operation, say project engineers.

Another early problem at Sarlux involved severe damage to the hydrogen removal and recovery membrane system due to contact with some minor amount of Selexol carryover.

This was solved by adding new high-efficiency coalescing separators in lieu of the conventional demisters used in the original design.

280 MW Api Energy IGCC plant. Two parallel train GE gasifiers produce syngas for a single GT13E2A gas turbine. This is a view of the sulfur recovery units (center), sour water stripping towers (right) and the Selexol regenerator and absorber.

Steady improvement gains

With resolution of initial equipment problems, and improved operating procedures, IGCC plant availability showed steady improvement.

During 2004, with four years of commercial operation behind it, the ISAB plant enjoyed around 93% capacity factor on syngas according to a report issued by one of the plant owners.

This was up from 89% during the third year of commercial operation, and 77% the year before that.

The Sarlux plant also witnessed a dramatic improvement within the frist three years of operation.

Capacity factor on syngas improved to 90%, climbing up from a lowly 55% the first year.

Adding operating time on backup fuel brings this figure to a very respectable 88%.

Although detailed data are lacking, current operation of the Sarlux plant is said to be quite satisfactory.

Api Energy design

The 280 MW Api Energia plant at Falconara Marittima differs from the other two IGCC plants in that it has two gasifiers feeding one gas turbine.

It features two parallel trains of Texaco gasifiers (now GE Energy) producing syngas for a single ABB GT13E2A gas turbine combined cycle unit.

Like the arrangement at ISAB, a syngas expander is used to recover excess pressure energy upstream of the gas turbine fuel control valve.

But, unlike the earlier Italian plants where the syngas is saturated by steam prior to combustion, compressed nitrogen from the air separation unit (ASU) is injected into the syngas for a 50% dilution for NOx control.

Another unique feature is the addition of an auxiliary boiler to supply plant steam in the event of gas turbine outage.

During normal operating conditions, the auxiliary boiler is kept at minimum load and the steam produced is recirculated into the steam and water cycle.

First-year jitters

Like the other plants, equipment and operating problems at Api seriously detracted from plant availability during its initial commercial service.

After about a year the plant owners awarded a contract to Foster Wheeler Italiania, the original EPC contractor, to resolve the problems and bring the plant up to design performance.

According to project engineers assigned that task, IGCC plant availability during the first two years of operation was in the range of 70% and caused investor concern.

It also resulted in high maintenance costs and created problems with plant neighbors due to excessive flaring and frequent steam safety valve discharge noise during plant upsets.

Improvement targets

The main problem areas for the Foster Wheeler "availability improvement" project initiated in 2002 had to do with low safety system effectiveness; low instrumentation reliability; metallurgical inadequacies; equipment performance limitations.

A reliability, availability and maintainability (RAM) study was conducted at the outset to provide a roadmap for improvements.

The study showed that the theoretical average equivalent availability of the plant operating on syngas was 87% -- taking into account the Falconara plant configuration and utilizing an industry RAM database relevant to

Commercially Operating IGCC Projects Worldwide. Table lists 14 commercially operating IGCC plants worldwide (including one now undergoing commissioning) that provide close to 3900 MW of generating capacity. Plants use a variety of feedstock coals, petroleum coke and other refinery residues. Nuon Buggenum plant recently introduced biomass to supplment its coal feedstock. The syngas-modified V94 gas turbines are Siemens designs built by Ansaldo. The Frame machines are GE designs.

Project	Startup	Rating	Feed	Product	Gasifer	Gas Turbine
Nuon (Demkolec), Buggenum, The Netherlands	1994	250 MW	coal/biomass	power	Shell	V94.2
Wabash (Global/Cinergy), Indiana USA	1995	260 MW	coal/coke	repowering	Conoco Phillips	1xFr 7FA
Tampa Electric, Polk County, Florida USA	1996	250 MW	coal/coke	power	GE/Texaco	1xFr 7FA
Frontier Oil, El Dorado, Kansas USA	1996	45 MW	coke	power/steam	GE/Texaco	1xFr 6B
SUV, Czech Republic	1996	350 MW	coal/coke	power/steam	Lurgi	2xFr 9E
Schwarze Pumpe, Germany	1996	40 MW	lignite/waste	power/methanol	Future Energy	1xFr 6B
Shell Refinery, Pernis, The Netherlands	1997	120 MW	visbreaker/tar	power/steam/H2	Shell	2xFr 6B
Elcogas S.A., Puertollano, Spain	1998	300 MW	coal/coke	power	Prenflo	1x V94.3
ISAB Energy, ERG/Mission, Italy	2000	520 MW	asphalt	hydrogen/power	GE/Texaco	2x V94.2K
Sarlux, Saras/Enron, Sardinia, Italy	2001	545 MW	visbreaker/tar	power/steam/H2	GE/Texaco	3x Fr 9E
Exxon Chemical, Singapore	2001	160 MW	ethylene tar	power/steam	GE/Texaco	2xFr 6FA
Api Energia, Falconara, Italy	2002	280 MW	visbreaker/tar	power	GE/Texaco	1xKA 13E2 Alstom
Valero (Premcor), Delaware City USA	2003	160 MW	coke	repowering	GE/Texaco	2xFr 6FA
Nippon Refining (NPRC), Negishi, Japan	2003	342 MW	asphalt	power	GE/Texaco Mitsubishi	1x701F
Eni Sannazzaro, AGIP Petrolia, Italy	2006	250 MW	oil residues	power/steam/H2	Shell	V94.2K
Total generating capacity		**3872 MW**				

Source: Luke O'Keefe, Burns & Roe

operating IGCC plants.

Plant owners and the project engineers took this figure as their reference target in pursuit of the multi-year availability improvement project.

As a result, a plant upgrade program was initiated, with modifications to be implemented during each of the three annual planned maintenance outages during 2002, 2003, and 2004.

Safety first

Among the plant-wide studies performed was a Safety Integrity Level study in accordance with international standards for more than 300 safety instrumentation system functions.

All of the specified modifications related to safety were implemented along with a number of corrective measures that were identified for overall IGCC plant design and operation.

Modifications related to plant reliability and performance were subjected to rigorous cost-benefit analyses and prioritized.

A series of instrumentation and control system reliability improvement measures included automated flow regulators to replace simple orifices, increased control loop redundancy, and high-performance CPUs and operator station controllers to handle heavy software loads.

Steam cycle

Particular attention was given to the auxiliary boiler system to insure its backup supply of steam to the refinery and to the gasifiers in the event of a combined cycle trip.

Basically, the burner management system was simplified and made more flexible to improve its reliability.

Several measures were taken to improve the reliability of the steam and water cycle, according to the project engineers, the most important of which included duplication of de-superheating stations to allow on-line maintenance.

An automatically actuated control valve was also installed at the auxiliary boiler outlet to replace the original on-off valve.

This was to allow a smooth and reliable release of high pressure steam to the atmosphere in the event of a combined cycle plant or steam turbine trip.

Materials upgrades

Reliability studies of the Falconara plant placed focus on two systems where materials upgrades were indicated, i.e. the gray water system and the oxygen system.

In the gray water system, corrosion and erosion phenomena were evident in carbon steel piping, equipment and control valves.

Metallurgical studies indicated that this was due to the effect of acidic conditions in the presence of solids (soot, ash) in these components. However, initial measures taken to neutralize the acids did not solve the problem.

Subsequent change to stainless steel for parts where the corrosion and erosion damage was most severe achieved the desired result.

The focus on the oxygen system came after a plant shutdown due to loss of oxygen, and the owner gave high priority to finding a solution to assure higher safety and reliability levels.

As a result, the original stainless steel material in some portions of the system handling high velocity oxygen was replaced with Monel 400 material.

Non-materials modifications to the oxygen system included adding new lines and isolation valves to improve system maintainability.

It involved replacing manual valves with multi-stage restriction orifices in each oxygen vent line, installing new automatic valves, adding instrumentation and controls for startup and shutdown of the gasifiers.

Critical equipment

One major equipment upgrade to achieve targeted RAM performance was to replace a 23 MW electric motor drive for the main ASU air compressor with a more powerful unit.

The original motor had been repaired after being severely damaged when a cooling water leak caused an insulation failure.

In the eyes of the owners and inspection engineers, the incident and subsequent repair left this critical plant item unreliable.

The replacement compressor mo-

Proposed 500 MW pet-coke refinery project in the U.S.

Given Europe's example of what can (and should) be done with refinery residuals, and the proven benefits of IGCC in a refinery application, there is growing interest in the U.S. for similar plants.

With new federal incentives for pet-coke IGCC plants now in place under the Energy Policy Act of 2005, plans have been announced for at least one plant and more can be expected to follow.

BP and Edison Mission Group (affiliate of Mission International) recently unveiled plans for a 500 MW pet-coke IGCC plant to be located at the BP refinery near Carson, California, south of Los Angeles. Plant startup date set for 2011.

This first-of-a-kind commercial-scale project will carry the IGCC theme one step further by featuring CO_2 separation and sequestration in the form of injection into deep reservoirs for enhanced oil recovery.

Combined cycle power unit will be fired with near-pure hydrogen that will remain from the syngas after it is stripped of about 90% of the CO_2 before the gas is fed to the modified gas turbine combustion system.

No information has been disclosed regarding the gasification or combined cycle suppliers. A final decision to go ahead with the proposed project is not expected until 2008.

tor is rated at 24.5 MW, providing some margin over the original design.

It also has many electrical and mechanical design upgrade features such as titanium water-to-air coolers that are corrosion resistant to the seawater coolant.

On top of this, the cooling system was redesigned in such a way as to preclude seawater coming in contact with the windings.

It also is equipped with an on-line rotor telemetry monitoring system to allow for thorough remote supervision of all motor operating parameters.

Seaside air intake

Apparently the seaside location of the plant was not fully taken into account in specifying the gas turbine inlet air filter to protect against salt air and water ingestion. The original filter lacked any special provisions for water removal.

Since the face of the gas turbine intake is only about 50 feet from the shoreline, and the site is subject to frequent winter storms and rough sea conditions, salt water droplet carry-over into the gas turbine compressor was quite predictable.

In addition, this environment caused the particulate-capturing ability of the filter media to deteriorate over a short time.

Considering the availability target set for the plant, the owners saw this problem as serious enough to justify replacing the original gas turbine inlet filter with one specifically designed for the plant site conditions.

Design requirements for the new filter included inlet flow face velocity not to exceed 2.7 meters per second, high droplet removal efficiency using a stainless steel demister section, a two-stage coalescer section, a bag-type pre-filter, and a last stage "fine" filter.

The new filter was installed and commissioned during the scheduled combined cycle outage at the end of 2003, and its performance has been reported as being highly satisfactory.

Lessons learned

Results of the three-year availability improvement project carried out at the Api plant are impressive and were mainly implemented during the first gas turbine major overhaul late in 2003.

After averaging only about 67% during the first three years of commercial operation, plant availability (as measured by percentage of operating hours relative to 8760 hours per year) jumped to 94% in 2004.

This performance substantially exceeded the 87% target and is indicative of the potential improvement possible in utilization and profitability.

The longer-term results, factoring in planned outages and aging of the new and modified equipment, will likely be more in line with expectations.

This experience with commercial-scale plants in Europe demonstrates that IGCC plants can operate at capacity factors comparable to, if not better than, conventional coal plants. ■

Select IGCC and Gasification Project Financings. These IGCC and gasification projects were privately project financed, and in several cases refinanced, with non-recourse arrangements based on project quality and pro forma.

Project	Sponsors	Financial Close	Feed	Products	Financing
Puertollano, Spain	EDF, Endesa, Iberdrola	1994	coal/coke	300 MW	non-recourse
ISAB Energy, Italy	ISAB, Mission Energy	March 1996 (refinanced)	asphalt	520 MW	non-recourse
Api Energia, Italy	Api, ABB	May 1996 (refinanced)	visbreaker tar	280 MW and steam	non-recourse
Sarlux, Italy	Saras, Enron	Nov 1996 (refinanced)	visbreaker tar	545 MW steam + H2	non-recourse
El Dorado. Kansas, US	Texaco	1996	petroleum coke	42 MW and steam	operating lease
Motiva, Delaware US	Star Enterprise	August 1997	petroleum coke	160 MW and steam	bonds
Coffeyville, Kansas US	Farmland, Texaco	Dec 1997	petroleum coke	1,000 tpd ammonia	bonds
Singapore Syngas	Texaco, Messer	Dec 2000	heavy oil	54 mmcfd syngas	non-recourse

Source: Luke O'Keefe, Burns & Roe

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing was served on this 16th day of March, 2007, via electronic mail and US Mail on:

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