OUC is both the majority owner and the operator of approximately 936 MW of coal-fired generation at its Stanton Energy Center facility. OUC's operating performance with these two units has produced long-term, sustained reliability along with a forced outage rate well below the national average and equivalent availability rate exceeding the national average.

1.2.2 PROJECT NEEDS AND OBJECTIVES

There are two principal needs to be addressed by the proposed OGP:

- Commercial demonstration of an advanced air-blown transport gasifier technology.
- Cost-effective integration with and fueling option for the planned combined-cycle power plant.

One of the purposes of DOE's CCPI program is to demonstrate coal-based power generation technologies at a scale that accelerates their widespread deployment within the power industry. The economic, environmental, and thermal performance of these technologies must be able to show progress consistent with DOE's goals. Thus, the primary objective of this project is to design, build, and operate a state-of-the-art commercial-scale coal *gasification island* utilizing KBR air-blown Transport Gasifier technology and integrate it with a planned *combined-cycle island.* Other objectives of the project include:

- To design, construct, and operate an advanced syngas cleanup system that includes sulfur removal and recovery; high-temperature, high-pressure (HTHP) particulate filtration; ammonia recovery; and mercury removal.
- To demonstrate high availability, high thermal efficiency, low cost, and low emissions of the IGCC in commercial operating mode.
- To develop an effective commercialization strategy to accelerate the Transport Gasifier technology penetration in the United States and international markets to achieve full repayment of DOE's cost share.
- To disseminate information on the development of the Transport Gasifier technology through reports and conference presentations. The information reported should include plant efficiency, environmental status, and cost successes for ready replication into commercial practice.

The technology to be demonstrated will utilize two air-blown Transport Gasifiers to fuel a nominal 285-MW combined-cycle power plant. The Transport Gasifier design is based on KBR's fluidized catalytic cracker (FCC) design. The Transport Gasifier offers a simpler and more robust method for generating power from coal than other alternatives. It is unique among coal gasification technologies in that it is cost-effective when handling low rank coals (i.e., coals with lower energy contents) and when using coals with high moisture and/or high ash contents. These coals make up half the proven reserves in both the United States and around the world.

The largest Transport Gasifier built to date, with a maximum coal-feed rate of 5,500 lb/hr, commenced operation in 1996 at the PSDF (a joint research facility sponsored by DOE, Southern Company, and other industrial participants). The operating experience at the PSDF has resulted in a deep understanding of Transport Gasifier environmental and thermal performance and its fluid mechanics, and also of the performance of supporting ancillary equipment such as coal-feed and ash-removal systems and HTHP gas filters. Economic and engineering evaluation studies completed by SCS in conjunction with DOE, the Electric Power Research Institute (EPRI), and KBR, conclude that the most economical application of the technology for power generation is as an air-blown Transport Gasifier.

From this experience, the design and operating parameters of the Transport Gasifier are well understood, and its potential advantages to the power industry have been well established. The technology is now ready to be demonstrated on a commercial scale to confirm these advantages—the objective of the OGP—after which it is projected to be widely deployed as an advanced coal-based power generating technology. It is planned that future IGCC units based on the proposed project's design and integration with the combined-cycle unit will be capable of generating more power and running at increased efficiencies.

The second need to be met by the proposed project is cost-effective fuel supply for electricity generation. As a public utility, OUC has the obligation to provide reliable and economical electric power service to its existing and future customers. To meet this obligation, OUC conducts ongoing, long-range power resource planning and load (i.e., demand) forecasting programs to predict its future power supply needs and evaluate available options to meet these needs. These programs also consider OUC's extensive efforts to encourage conservation and load management programs to reduce future power needs.

Florida statutes require all Florida utilities to prepare planning documents looking ahead 10 years (10-year site plans). Based on the anticipated continuing growth in the Orlando area, OUC's latest plan has forecast needs for approximately 300 MW of additional generating capacity in the 2010 timeframe (Black and Veatch, 2005). The forecast states that the planned combined-cycle generating unit will be the means to meet that need. OUC needs this new capacity to maintain adequate system reliability in meeting the expected increasing demands of its customers for electrical energy. The objective of the power resource planning process is to ensure that future service to OUC's customers remains economical and reliable, while meeting all environmental regulatory requirements and standards.

In Florida, the Florida Public Service Commission (FPSC) is the exclusive forum for the determination of need for a proposed power plant. FPSC need determinations are based on electric system reliability and integrity considerations and whether the proposed plant is the most cost-effective alternative to meet power demands. Thus, before the planned combined-cycle unit could be built: (a) OUC must file a petition to determine need for the new electrical power plant and related facilities with FPSC pursuant to Section 403.519, Florida Statutes (F.S.), (b) a public hearing on the petition to determine need for the power plant must be held by FPSC, and (c) FPSC must review and approve that petition. FPSC's decision on such a petition is independent of the proposed OGP.

One of the purposes of the OGP is to demonstrate integration of the Transport Gasifier with a combined-cycle plant on a commercial scale. However, it is important in this introductory chapter to emphasize that the combined-cycle plant planned by OUC is not part of the DOE project and will not be constructed with DOE funding. Instead, DOE's funding will support only the gasification island and its ancillary equipment. However, integrating the gasifier with the planned combined-cycle unit and demonstrating operation of the unit on syngas is clearly integral to the overall success of the project. The combined-cycle equipment is, therefore, considered a *related action* for purposes of this EIV, and the impacts of the entire IGCC facility will be assessed within the scope of this EIV.

1.2.3 PROJECT BENEFITS

Benefits associated with this project can be described according to general categories: operational, socioeconomic, and environmental. Further, these benefits can be considered in local, regional, and national contexts.

From an operational perspective, the OGP is designed, first and foremost, to address and overcome challenges associated with scaling up from pilot to commercial size and successfully demonstrating the Transport Gasifier technology, which is expected to have national (and international) implications. The OGP also has the potential to significantly reduce future coal-based power generation costs while using coal to satisfy the nation's energy independence objectives. The use of coal, an abundant, low-cost domestic fuel, is consistent with the national goals of the CCPI program. Providing a cost-effective fueling option for meeting the requirements of OUC's generation expansion plan constitutes a local and regional operational benefit associated with this project.

Successful demonstration of the Transport Gasifier at Stanton will have a number of other operational benefits compared to other IGCC technologies or standard coal-based generation technologies (e.g., pulverized coal [PC]). These include:

- Efficiency improvements.
- Reduced capital costs in line with DOE goals for coal-based generation technologies.
- Competitive cost of electricity with the best opportunity to achieve DOE's cost goals.

- Potential for rapid commercial deployment (potentially including refueling natural gas-fired combined-cycle power plants to operate using more cost-effective fuel).

Socioeconomic benefits are those normally associated with new industrial activity, including increased local tax base and employment opportunities. These benefits are discussed in detail in Section 3.1.10.

Consistent with DOE objectives, a major objective of the OGP is to maintain acceptable environmental performance while commercial scale operation is being demonstrated. Emissions from the IGCC unit are expected to be less than emissions from the existing fleet of conventional coal-based power generating technologies. A successful demonstration will result in the availability of a coal-based technology to the utility industry having lower emissions than conventional coal technologies. In addition, the project will have comparably lower water consumption and land use requirements than conventional coal technologies.

In summary, the proposed OGP unit will demonstrate the air-blown Transport Gasifier technology, for which the primary market is the global (including United States) coal-based power generation industry. The economic advantages of this technology will be tested, and its potential for wider use confirmed. The proposed demonstration project is an essential step in the commercialization of the process. Once the OGP unit is constructed and operated and its advantages confirmed, the Transport Gasifier process will be well situated to be effectively marketed worldwide.

The operational, socioeconomic, and environmental benefits associated with successful demonstration of the Transport Gasifier compare favorably to those from other coal-based technologies. Long-term and cumulative effects of the commercial use of this technology should be beneficial to the environment when compared to conventional coal-fired technologies. Further, commitments of vital resources are minimized by IGCC power generation by virtue of higher thermal efficiency, which provides more energy at a lower level of resource consumption.

1.3 OVERVIEW OF PROPOSED PROJECT

The OGP demonstration unit will be built in Orange County, Florida, and co-owned by OUC and Southern Power Company. It will gasify sub-bituminous coal and supply syngas fuel for the generation of 285 MW of electricity (net) at a heat rate of 8,430 British thermal units per kilowatt hour (Btu/kWh) (40.5 percent efficiency, higher heating value basis).

1.3.1 PROJECT LOCATION AND SETTING

The OGP will be constructed on a portion of OUC's Stanton Energy Center in eastern Orange County. Figure 1.3-1 shows the site relative to Orlando and major highways. Figure 1.3-2 shows the Stanton site and surrounding area using a recent aerial photograph.

The site consists of 3,280 total acres. It was certified as a power plant site through the Florida Electrical Power Plant Siting Act (FEPPSA) in December 1982, with an ultimate site generating capacity of 2,000 MW. The first unit built was Unit 1, a 468-MW pulverized coal-fired unit that began commercial operation in June 1987. Unit 2, another similarly sized pulverized coal-fired unit, began commercial operation in June 1996. During the initial site development, the facilities for coal delivery, handling and storage and waste handling and disposal (onsite landfill) were also constructed. Both Units 1 and 2 combust bituminous coal from the central Appalachian region. Units 1 and 2 are also permitted to burn natural gas and landfill gas. All of the coal for Units 1 and 2 is delivered to the site by rail. The most recent unit added to Stanton was Unit A, a 633-MW natural gas-fired combined-cycle unit. It is also permitted to fire distillate fuel oil. Unit A began commercial operation in October 2003.

Unit 1 is equipped with low-nitrogen oxides (NO_x) burners to limit formation of NO_x, a wet limestone scrubber (flue gas desulfurization [FGD] system) that captures 90 percent of sulfur dioxide (SO_2) emissions, and an electrostatic precipitator (ESP) that collects

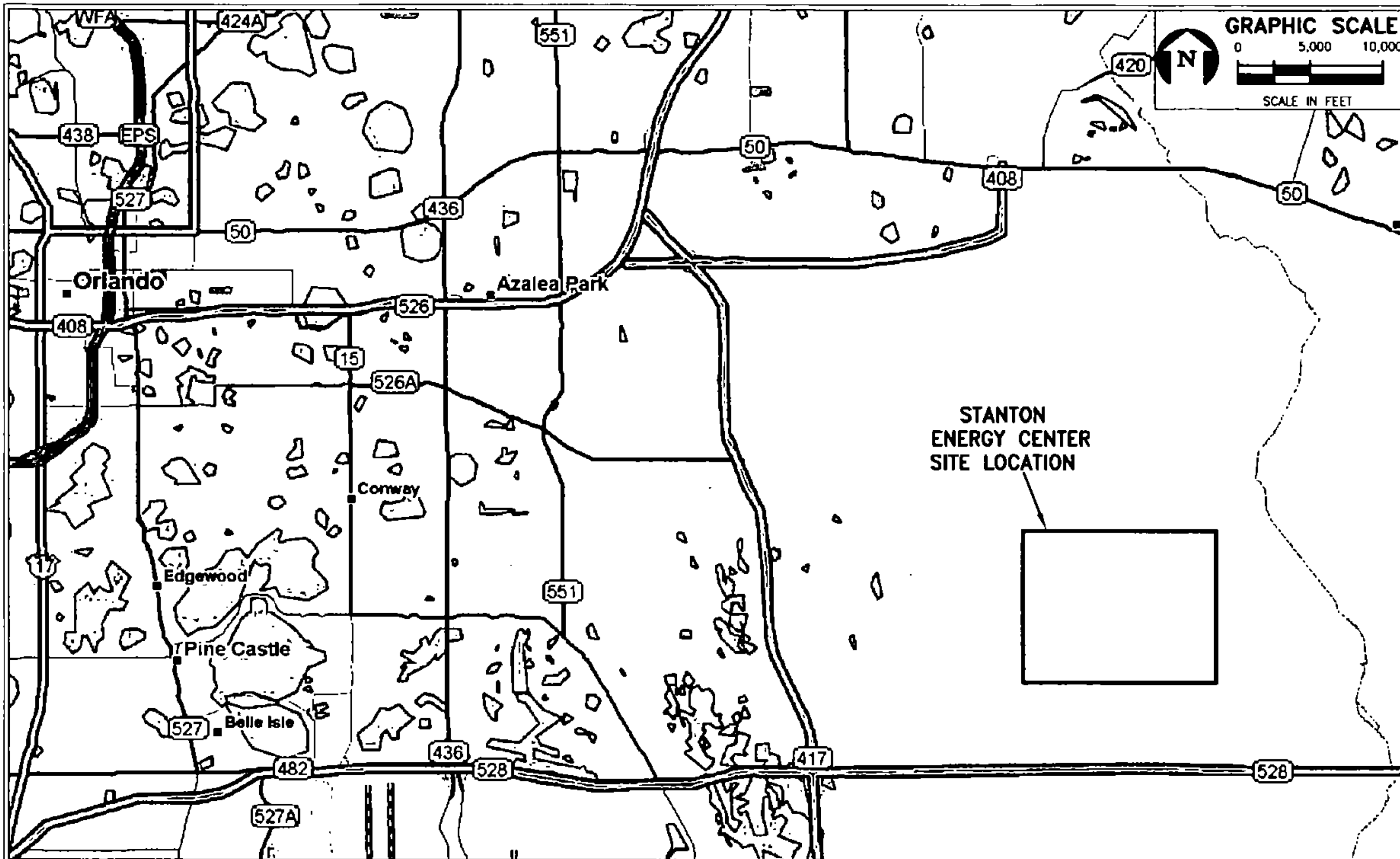

FIGURE 1.3-1.
STANTON SITE LOCATION RELATIVE TO ORLANDO

Source: DeLorme, 2003; ECT, 2005.

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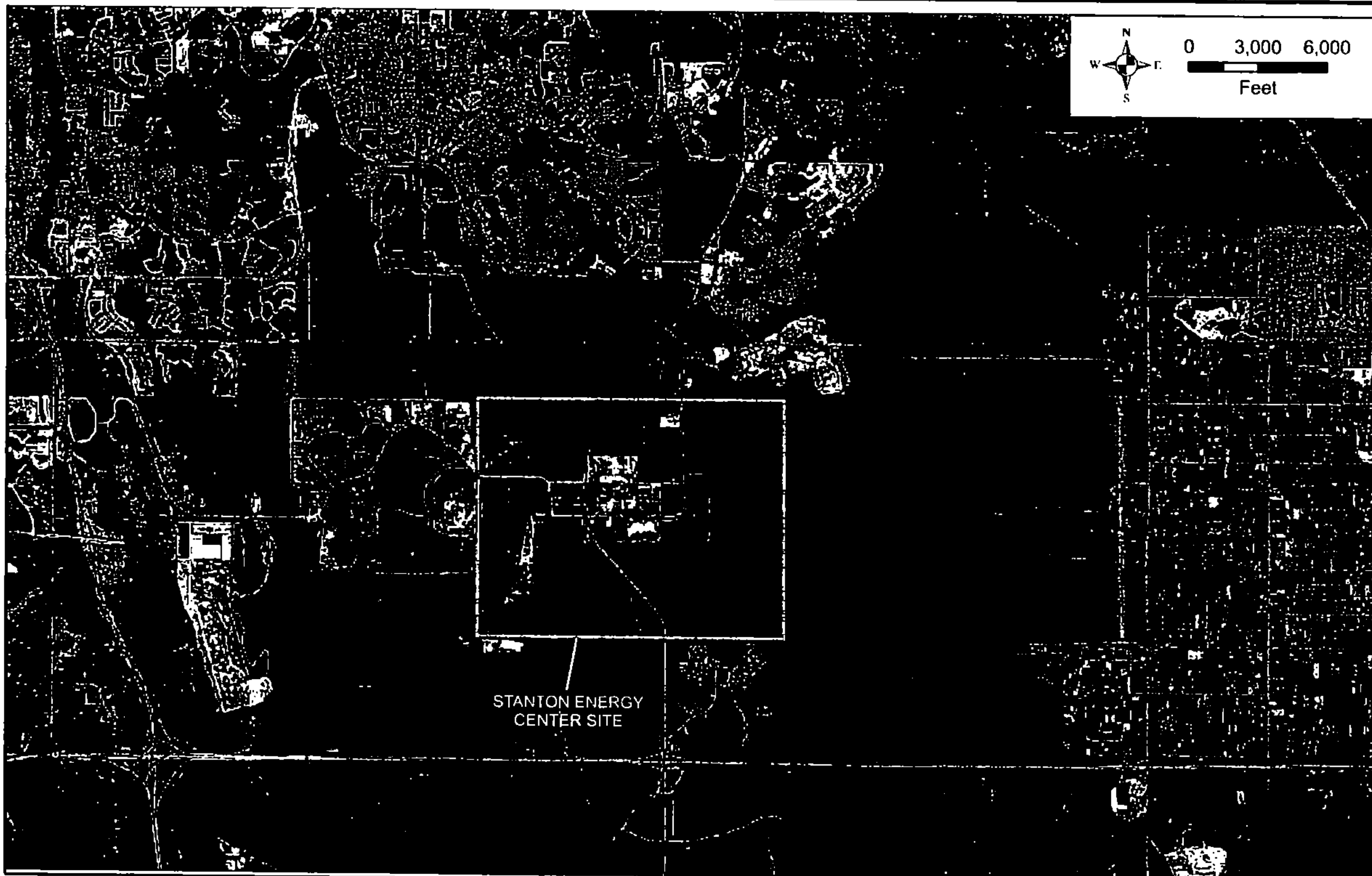

FIGURE 1.3-2.
2004 AERIAL OF STANTON SITE AND SURROUNDING AREA

Sources: SJRWMD Aerials, 2004; ECT, 2005.

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99.9 percent of particulate matter (PM) emissions. Unit 2 is also equipped with a low-NO_x burners, an FGD system, and an ESP. Additionally, Unit 2 has a selective catalytic reduction (SCR) system to further reduce NO_x emissions. Unit A also utilizes low-NO_x burners and an SCR system.

The FGD systems for Units 1 and 2 use a total of approximately 50,000 tons per year (tpy) of Florida limestone, which is trucked onto the Stanton site. All of the stabilized FGD scrubber sludge is landfilled onsite.

The Stanton Energy Center has 204 fulltime employees, 183 of whom operate Units 1 and 2, while 21 operate Unit A. Another 100 persons from specialty contractors might also be onsite at any given time.

The Stanton site also includes a large make-up water pond where reclaimed water from the nearby Orange County Eastern Water Reclamation Facility is received and stored. This pond provides water for cooling and other process uses within the plant.

The Stanton Energy Center is a zero-discharge facility. This means that there are no effluents discharged offsite. All wastewater streams are recycled onsite. After maximum reuse, wastewater is piped to the onsite wastewater treatment facility, where solids are removed and disposed of in the onsite landfill and water is recycled to the cooling towers.

Of the Stanton site's 3,280 acres, approximately 1,100 were licensed in 1982 for construction of power generating and associated facilities. The OGP and the planned combined-cycle unit will be built entirely within this previously developed 1,100-acre area. A short transmission line interconnection to an onsite substation may occupy a small amount of additional land.

Alafaya Trail (from the north) currently provides the primary access to the Stanton site. Limited ingress/egress is also available from a southern access road. The immediately surrounding road system—and site access—will be improved greatly by the completion of the Avalon Park Boulevard extension project, currently slated to commence construction in 2005. Section 5.2 discusses this road improvement project and how it will affect the Stanton site area in more detail.

The Stanton site is zoned Farmland Rural, as is much of the surrounding property. Land uses at adjacent properties include mixed commercial-residential to the north, a preserve and park to the east, a correctional facility to the south, and a municipal landfill to the west. More details regarding surrounding land uses and zoning are provided in Section 2.10.

1.3.2 DESCRIPTION OF TECHNOLOGY

The proposed gasification system is projected to produce a fuel that, when combusted, will achieve high environmental standards for emissions of SO_2, NO_x, PM, and mercury. Means of reducing water consumption are incorporated in the design, and potential uses for the gasification ash have been identified. The design also incorporates removal and recovery of commercial-grade anhydrous ammonia and sulfur by-products. The syngas produced by this advanced technology will be used in a combined-cycle power-generating unit that takes advantage of proven, reliable, and widely demonstrated technology.

Figure 1.3-3 provides an overall block flow schematic diagram of the proposed project and its integration with the combined-cycle unit.

1.3.2.1 <u>OGP Gasification Island</u>

The OGP will employ two identical gasifier trains. Once the coal enters the gasification island structure, it will be separated to feed the two parallel trains. Each gasification train is designed to produce 50 percent of the total syngas requirement for the gas turbine. With few exceptions, the equipment in each train will be completely separate, and the two syngas streams will be combined just prior to the gas turbine. The exceptions are:

- The coal will enter the gasification island structure on a single conveyor and fall onto a tripper conveyor system that will separate the coal between the two gasification trains.

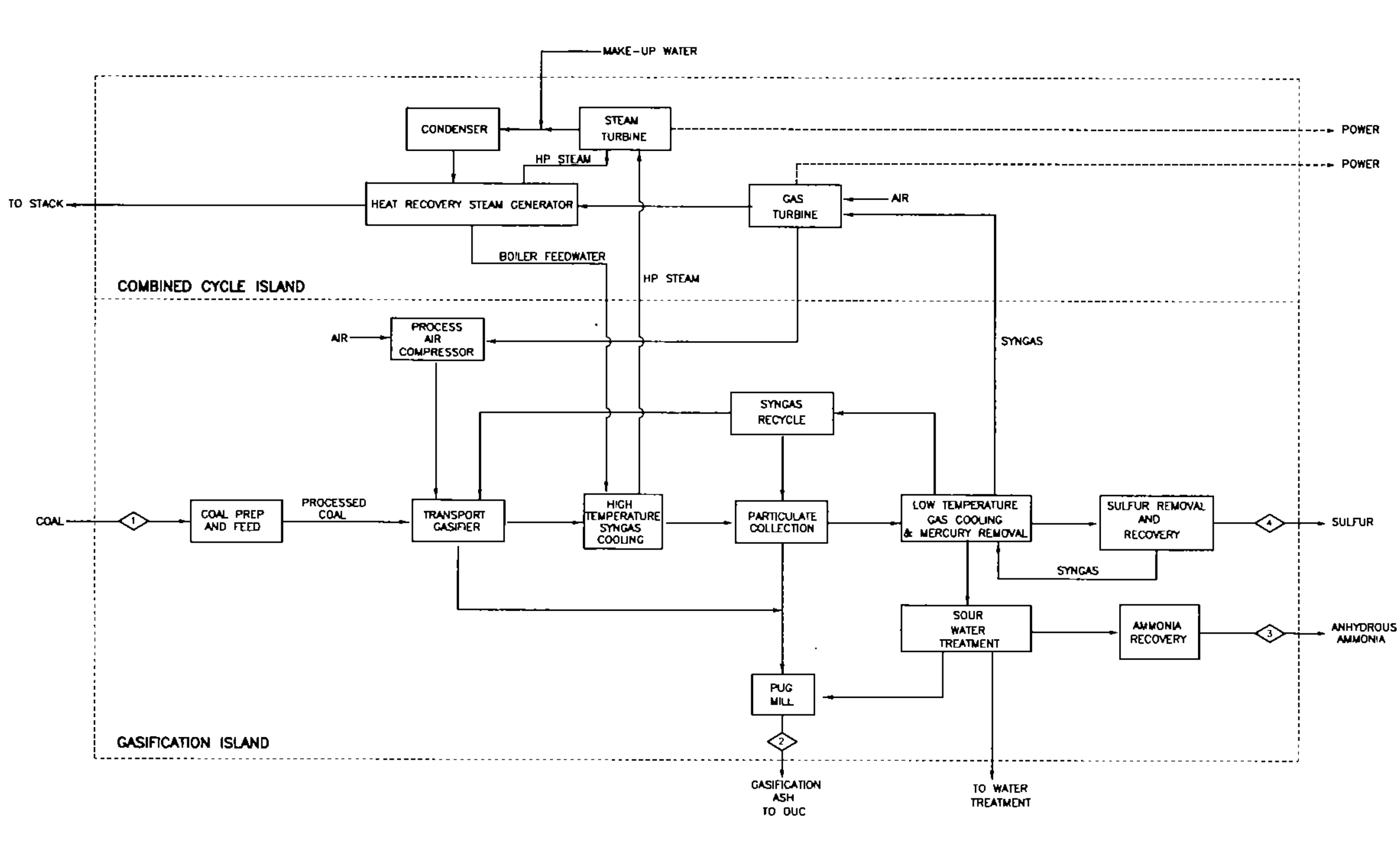

FIGURE 1.3-3.
OVERALL PROCESS FLOW DIAGRAM

Source: SCS, 2005.

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- There will be a startup stack and multipoint flare for the gasification island.
- The sulfur removal equipment will include two contactors, one for each of the two syngas streams. However, there will be a single solvent recovery process for the two contactors.
- There will be a single sour water treatment and ammonia recovery system that serves both trains.

The design coal feed rate to each gasifier will be approximately 68.5 tons per hour (ton/hr) (137 ton/hr, total). The plant will be 100-percent coal-fired, designed for low-sulfur Powder River Basin (PRB) sub-bituminous coal. Carbon conversion is projected to be 97 percent. Sulfur and other pollutants in the coal will be removed from the syngas before delivery to the gas turbine. Each gasifier will produce approximately 225 ton/hr (450 ton/hr, total) of syngas having a lower heating value of approximately 125.7 British thermal units per standard cubic foot (Btu/scf). Table 1.3-1 summarizes the main inputs to and outputs from the gasifier. The following paragraphs provide details of the key processes within the gasification island.

Coal Preparation and Feeding

The design coal is sub-bituminous PRB with an as-received higher heating value of 8,760 British thermal units per pound (Btu/lb) and 0.26 percent sulfur. Two to three unit trains per week, each train using the existing unloading system for Units 1 and 2, will deliver the coal (see also Section 1.4.2.2). The conveyor delivers the coal into a hopper, where a belt conveyor delivers it to a radial-pedestal stacker conveyor that forms a kidney-shaped pile with a capacity of 170,000 tons, equivalent to 45 days of live storage at the design feed rate. The coal from the live-storage section of the pile will be discharged onto a reclaim belt conveyor and then delivered to the crusher shed at grade. After passing through tramp screens, a magnetic separator, and an automatic sampling system, a single crusher reduces the coal size from 3 to 0.75 inch. The crushed coal is transported on a belt conveyor to a tripper conveyor in the process structure and then into crushed coal silos.

Table 1.3-1. Expected Operating Characteristics—Input and Output Quantities Specific to Transport Gasifier Island

		Description	Quantity
	Inputs		
1	Coal	Designed for PRB sub-bituminous coal used to produce syngas	274,000 lb/hr
	Sand	Used once at initial startup to make up gasifier bed; the bed material may be recycled, reducing/eliminating the need for additional sand; additional requirements of sand to be determined by operational experience	62 tons (for initial startup)
	Natural gas	Used during startup/trips/transitional periods of gasifier operation as needed	50 (flare pilot) to 31,000 lb/hr (during startup)
	Nitrogen	Inerting gas, purge flow	Nitrogen plant capacity = 30 ton/hr
	Outputs		
	Syngas	Coal derived syngas produced by gasifier for combustion in gas turbine	890,000 lb/hr (gasifier island at full load)
2	Gasification-ash (g-ash))	Fine g-ash removed from hot-gas filter vessel (possibly some from gasifier); contains more carbon than combustion ash does	18,300 lb/hr
3	Anhydrous ammonia	Ammonia removed in scrubber and captured in sour water treatment plant	1,960 lb/hr
4	Sulfur	Product of sulfur recovery process	760 lb/hr

Source: SCS, 2005.

A screw conveyor feeds crushed coal from each storage silo to its dedicated pulverizer. The pulverizers are roll-mill crushers using hot gas to dry the coal. The inert, recirculating drying gas enters at the base of the pulverizer, and this mixture of pulverized coal and gas is conveyed to a cyclone, where the majority of the coal is removed and falls through a rotary pressure seal into a surge bin. The dusty gas then flows to a baghouse where the coal is separated and discharged through a rotary pressure seal into the same surge bin. An induced-draft fan after the baghouse drives the gas through the drying circuit.

Water-cooled shell-and-tube exchangers cool the drying gas to condense the moisture picked up in the dryer. Since the condensate withdrawn from the knockout drum may include coal dust transmitted through the baghouse, it is passed to the sour-water treatment plant prior to reuse. The cooled gas is reheated in shell-and-tube heaters using intermediate-pressure steam. Then the hot gas is recirculated back to the pulverizer to dry more coal. Steam heating is preferred because it avoids the operating cost associated with fuel-fired burners. It also minimizes the amount of moisture present in the drying gas and improves drying efficiency.

The pulverized coal is transferred from the surge bin by gravity to a high-pressure coal feeder. The coal enters the feeder at atmospheric pressure and the pressure is then increased to the operating pressure of the gasifier.

Transport Gasifier

The design of the Transport Gasifiers is based on KBR's FCC technology and SCS's operating experience at the PSDF. Each gasifier consists of several components, as shown in Figure 1.3-4. Each of the two Transport Gasifiers will be designed to convert the 68.5 ton/hr of PRB coal into approximately 450,000 lb/hr of syngas (850 million British thermal units per hour [MMBtu/hr]). The gasifiers will be constructed from refractor-lined pipe and have a height of approximately 160 feet (ft).

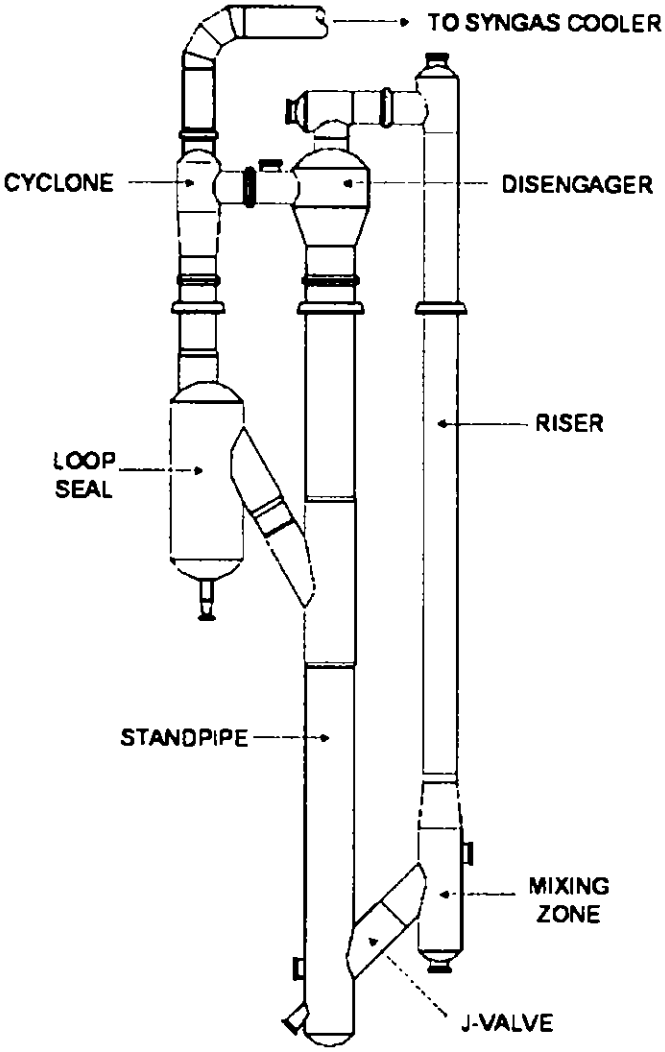

FIGURE 1.3-4.

SIDE ELEVATION OF A TRANSPORT GASIFIER

Source: SCS, 2005.

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Nearly 350 ton/hr of compressed air are supplied to the two gasifiers during operation. This air originates from two sources; roughly 25 percent of the air will be extracted from the combined-cycle unit's gas turbine, and the balance is ambient air.

Coal and air are fed into the mixing zone at the base of the riser section and mixed with gasifier ash recirculated through the *J-valve* from the standpipe. Gasifier ash is primarily coal ash and unreacted carbon but may contain sand. Coal is fed near the top of the mixing zone and air is fed at the bottom. Oxygen in the air is consumed by carbon present in the recirculating ash, forming primarily carbon monoxide (CO), and releasing the heat required to maintain reactor temperature. A consequence of this partial oxidation is that the coal devolatilizes in an almost oxygen-free environment. This staging effect results in a syngas with more methane than that from other fluidized-bed gasifiers. The hot recirculating ash heats the coal rapidly, minimizing tar formation.

Gasification ash and syngas pass from the mixing zone up to the riser. Syngas and gasification ash pass to a disengager where larger, denser particles are removed by gravity and fall into a standpipe. The syngas passes to a cyclone where most of the remaining gasification ash is removed and passed into a loop seal. The syngas leaving the cyclone passes along a refractory-lined pipe to the high-temperature syngas cooler, and after cooling, passes along a metal alloy pipe to the HTHP filter for final particulate removal.

Gasification ash flowing through the cyclone loop seal combines in the standpipe with gasification ash from the disengager. The combined stream passes down the standpipe and through the J-valve into the mixing zone. The J-valve and loop seal are nonmechanical valves that allow the gasification ash to flow against a reverse pressure gradient. To achieve reliable flow in these valves, the solids have to be well aerated. Recycled syngas is used for aeration rather than nitrogen to avoid diluting the product syngas and to reduce operating costs.

To maintain constant gasifier bed inventory, gasification ash can be removed periodically from the lower region of the standpipe. The gasification ash, still at pressure, flows through a bank of cooling tubes and heat passes into the condensate system. The gasification ash is cooled and then passes into a lock vessel to be depressurized. Syngas vented from the lock vessel passes to the syngas header to be compressed and returned to the Transport Gasifier. Nitrogen is used to pressurize the lock vessel. If required, sand can be fed to increase the gasifier solids inventory.

There are currently several options under consideration for reuse or disposal of the gasification ash. Please see Sections 1.4.2.5 and 1.4.4.3 for further detailed discussion of these options.

High Temperature Syngas Cooling

As shown in Figure 1.3-3, the syngas stream leaving each gasifier cyclone passes to a high temperature syngas cooler that lowers the syngas temperature before it enters the HTHP filter system. The heat transferred is used to raise the temperature of high-pressure superheated steam. The heat duty of each syngas cooler is approximately 190 MMBtu/hr.

The syngas cooler consists of three stages: an evaporator, a superheater, and an economizer. The evaporator has a natural circulation steam drum operating at above steam turbine inlet pressure and at saturated temperature. The steam raised in the evaporator is passed to a superheater, where it is heated to the steam turbine inlet temperature. This steam is mixed with the superheated steam exiting the combined-cycle unit's heat recovery steam generator (HRSG) before passing into the steam turbine. Boiler feed water enters the economizer and is heated to near saturation before entering the steam drum.

All three coolers are shell and tube heat exchangers, with the particulate-laden syngas flowing downward in a single pass through vertical tubes. The cooling fluid, water or steam, flows upward in a single pass through the shell side of the exchanger.

Particulate Collection

Particulate-laden syngas leaves the high temperature syngas cooler and enters the HTHP filter system. The filter system uses rigid, barrier-type filter elements to remove essentially all of the particulate in the syngas stream. Recycled syngas is used to pulse clean the filters as they accumulate particulate from the unfiltered syngas. The cleaned syngas particulate loading is projected to be less than 0.1 part per million by weight (ppmw). Downstream of each filter element, a safeguard device is installed to protect the combustion turbine from particulate-related damage in the event of a filter element failure.

Each of the two HTHP gas filter systems removes approximately 5 ton/hr of fine particulate from the syngas stream. The particulate (gasification ash) is cooled and depressurized to atmospheric pressure before leaving the gasifier island.

The syngas streams exit the filter vessels and flow to the low-temperature heat recovery system. The fine ash, still at pressure, flows down through a bank of cooling tubes and the heat is transferred to the condensate system. The cooled solids pass into a proprietary continuous fine ash removal system.

<u>**Low Temperature Gas Cooling and Mercury Removal**</u>

Before the filtered syngas leaving the HTHP filters is combusted in the gas turbine, sulfur, mercury, and nitrogenous-compound content is decreased. Cooling the syngas facilitates removal of these species, along with hydrocarbons, fluorides, and chlorides. Recuperative exchangers are incorporated in the cooling circuits to keep the final *sweet* syngas (syngas with sulfur removed) temperature high and so help preserve thermal efficiency.

The syngas leaves each HTHP filter and is cooled to the operating temperature of the sulfur removal process using high- and medium-temperature recuperators. Both coolers condense water and certain hydrocarbons from the *sour* syngas (i.e., syngas that has not gone through the sulfur removal system). The water dissolves almost all the nitrogenous compounds, chloride, and fluoride present along with lesser amounts of carbon dioxide (CO_2), CO, hydrogen sulfide (H_2S), and carbonyl sulfide (COS). This aqueous mixture is removed from the syngas flow in a knockout drum after the last cooler and passed to the sour water treatment plant. An aqueous scrubber is located downstream of these exchangers to further reduce the ammonia and other constituents in the syngas. The gas then flows into the sulfur removal process for H_2S removal before re-entering the low-temperature gas cooling area to be reheated and then combusted in the gas turbine.

As the gas is being cooled, it flows through additional gas cleanup processes. One of these is a COS hydrolysis unit that catalytically converts most of the COS to H_2S. The desulfurization process will not remove COS from the syngas stream, so the COS is converted to H_2S to minimize sulfur emissions. The reaction takes place over an alumina-based catalyst. The second reactor is a packed bed of sulfur-impregnated activated carbon to remove mercury from the syngas.

Sulfur Removal and Recovery

Syngas leaves the low-temperature gas cooling system at a temperature slightly above ambient and enters the sulfur removal process. In this process, the syngas is contacted with a solvent that removes a high percentage of the H_2S from the syngas stream. The H_2S in the solvent is converted to elemental sulfur, which is sold as a by-product. The solvent is regenerated and returned to the sulfur removal process. The sweet syngas leaves the contactor at a temperature slightly above ambient and then reenters the low-temperature gas cooling process where the syngas is heated before it is combusted in the gas turbine.

Prior to final recuperation, approximately 2 percent of the sweet syngas is removed and passed to the syngas recycle system. Some of this syngas is sent to the pulse-gas reservoirs and used to pulse clean the HTHP filters, and the remainder is used for aeration in the gasifier.

Isolation valves before the gas turbine allow one gasifier train to be brought on line while the other remains out of service. This arrangement simplifies the overall plant startup and, by allowing one unit to remain in service when the other is offline, contributes to increased overall plant availability.

The combined-cycle unit's gas turbine compressor provides the combustion air for the syngas and approximately 25 percent of the air required by the gasifier at full load. The remaining air required is delivered by a motor-driven process air compressor.

Sour Water Treatment and Ammonia Recovery

The water removed by the coal preparation system, the process air compressor intercoolers, water condensed from the syngas in the low-temperature gas cooling process, and water produced in the sulfur removal process is collected and sent to the single sour water treatment and ammonia recovery unit that treats approximately 150 gallons per minute (gpm) of *sour water*. The combined water flow passes to a filter to remove particulate and an activated carbon bed to remove organic material before entering a degassing drum. The ammonia in the water retains most of the dissolved H_2S, and the gas released is mainly light hydrocarbons, which pass to the vent gas recycle header. The filter cake and spent activated carbon will be disposed of in a manner that complies with applicable regulations.

Next, the sour water is heated in a stripped-water recuperator and passed to the steam-heated H_2S stripper where H_2S, hydrogen cyanide (HCN), CO, and CO_2 are released and passed to the vent gas recycle header. The header syngas stream is compressed and injected into the oxidation zone of the gasifier, where the HCN is destroyed. The water from the H_2S stripper discharges to the steam-heated ammonia stripper to produce a concentrated ammonia solution. The water drawn from the bottom of the ammonia stripper passes to the stripped-water recuperator and is pure enough for plant reuse.

The concentrated ammonia solution is further processed in two additional steam-heated strippers, the first releasing any remaining dissolved H_2S into the vent gas recycle header and the second increasing the ammonia concentration to 99.7 percent. The water drawn from the bottom of the columns is sufficiently pure for plant reuse. The ammonia produced is commercial-grade anhydrous ammonia, which OUC and SCS intend to use at Stanton in the other, existing onsite generating units (see Section 1.4.4.3). Excess anhydrous ammonia may be sold in the commercial market.

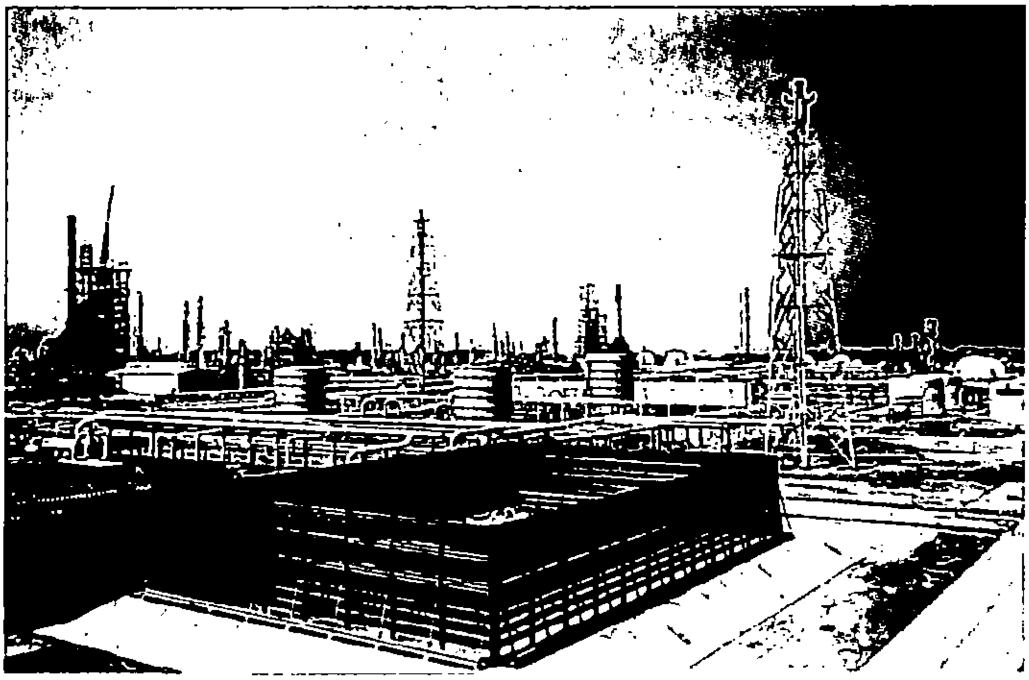
Flare

Although not shown in Figure 1.3-3, the gasification island will be equipped with a flare to combust syngas during startup and during plant upsets, such as a trip of the combined-cycle unit's gas turbine. A *multipoint* flare system will be used for the OGP and has been selected in preference to the more conventional stack flare design. The multipoint design, like the stack design, is well proven in the petrochemical industry and has been installed in hundreds, if not thousands of applications. Figure 1.3-5 shows two photographs of representative applications of the multipoint flare system similar to that planned for the OGP.

Relative to stack flares, the multipoint flare is a newer technology and was developed to resolve aesthetic issues (e.g., visual impacts) related to flares. Instead of having a single stack that is 100 to 200 ft tall with a single flame that may also be several hundred feet long and visible for many miles, the multipoint flare divides the gas into a number of smaller flames. These flames will be placed behind a thermal barrier fence. The multipoint design places the burners only approximately 10 ft above ground level. For this project the flare system will have a footprint of approximately 214 by 123 ft. The surrounding thermal barrier fence will be 20 ft tall. Flame temperature when fully employed will be approximately 1,800 degrees Fahrenheit (°F), and flame height will rise to approximately 40 ft above the burners at full load. The flame will be smokeless and invisible during the day (only shadows of the heat effects will be visible). At night, the blue/purple flame will be visible for some distance. Eight pilots fired with natural gas at a flowrate of 80 standard cubic feet per hour (scf/hr) per pilot will be on at all times.

1.3.2.2 Related Action Combined-Cycle Island

While the combined-cycle unit is itself not part of the project and will be built regardless of the gasifier, integration of the OGP with the combined-cycle unit is an objective. Although a final selection has not been made, the current IGCC design basis assumes a General Electric (GE) 7FA gas turbine (or combustion turbine [CT]) will be used. GE has designed and built 20 gas turbines (primarily 7FA designs) for operation on syngas from oxygen-blown gasifiers, including the Wabash River and Polk Power Station Clean Coal



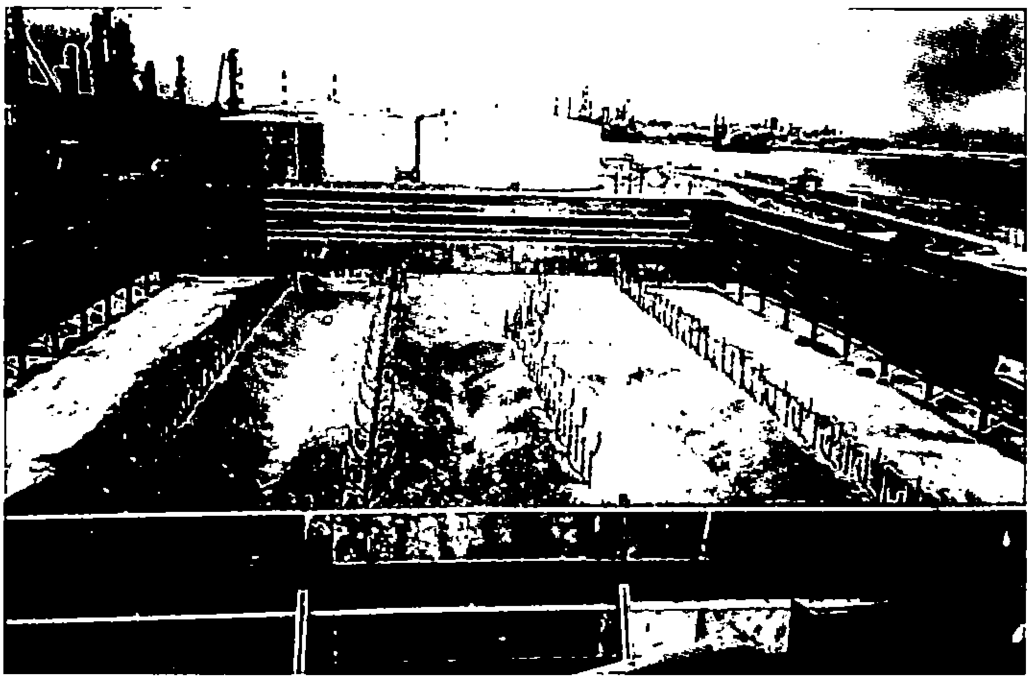


FIGURE 1.3-5.

TWO REPRESENTATIVE APPLICATIONS OF MULTIPOINT GROUND FLARE SYSTEM

Source: Callidus, 2005.

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Technology Demonstration Projects, which employ coal-based oxygen-blown IGCC technologies. The total 7FA fleet operating time on syngas is approximately 600,000 hours. Some of the syngas-operated gas turbines have approximately 50,000 hours of operation.

The thermal and environmental performance understanding developed from GE's test-stand data and commercial projects have been shared with SCS's engineering staff in preparation for the OGP unit design. To prevent flashback caused by the hydrogen content of the syngas, the CT will utilize diffusion flame-type combustors. These combustors are also capable of burning natural gas. When syngas is not available during startup and gasifier outages, the CT will fire natural gas.

The IGCC unit's combined-cycle island power block will consist of the CT/generator unit with a dedicated HRSG, a single steam turbine generator (i.e., a 1-on-1 CT/HRSG configuration), and associated auxiliary and control systems. The CT/HRSG unit will be constructed to allow only combined-cycle operation (i.e., the CT will not have a bypass stack allowing simple-cycle operation). The HRSG will be equipped with natural gas-fired duct burners to boost power generation capability during periods of peak demand. Firing syngas from the OGP as a base load unit, the combined-cycle unit will produce a net of 285 MW of electricity. When firing only natural gas in both the CT and HRSG duct burners, the capacity of the combined-cycle unit is 310 MW.

Figure 1.3-6 provides a simple schematic of a basic combined-cycle system showing a CT, an HRSG, and other key components. CTs are advanced technology engines that convert latent fuel energy into mechanical energy using compressed hot gas (i.e., air and products of combustion) as the working medium. CTs deliver mechanical energy by means of a rotating shaft that is used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. In the CT cycle, ambient air is first filtered and then compressed by the CT compressor section. The CT compressor section increases the pressure of the combustion air stream and also raises its temperature. The compressed combustion air is then combined with fuel, which is ignited in

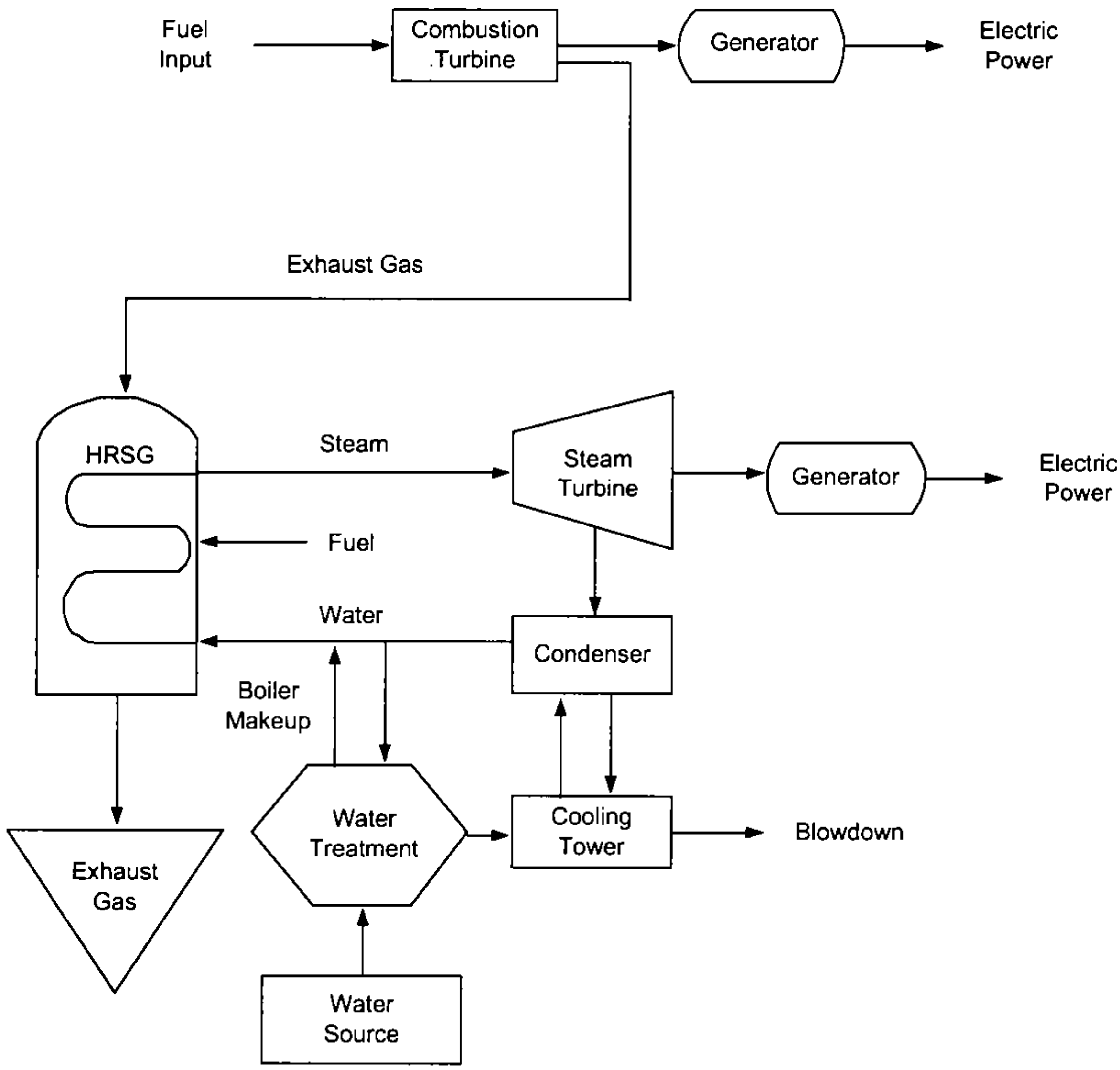

FIGURE 1.3-6.

SIMPLIFIED FLOW DIAGRAM OF A BASIC COMBINED-CYCLE POWER SYSTEM

Source: ECT, 2005.

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the CT's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases expand and drive the CT's turbine section to produce rotary shaft power. The turbine rotor is coupled to an electric generator as well as to the CT combustion air compressor rotor.

When CTs are used as simple-cycle (stand-alone) units, the hot combustion gases are released to the atmosphere at approximately 1,000 °F after they have passed through the turbine. The efficiency of a power plant's electric power production is significantly improved when the simple-cycle design is modified to include an HRSG and a steam turbine in what is termed a combined-cycle power plant. In a combined-cycle system, the heat in the CT exhaust gases is used to generate steam in an HRSG, where gas temperatures are reduced to approximately 270°F before release to the atmosphere. The steam is then used to drive a steam turbine and generator to produce additional electricity, as shown in Figure 1.3-6.

The CT exhausts into a conventionally designed, triple-pressure level HRSG. When operating on syngas, the normal HRSG gas exit temperature is above the acid dewpoint temperature and eliminates problems with wet corrosion.

Condensate from the steam turbine condenser is used for cooling in the gasification process and then returned to the HRSG and further heated before being deaerated. High-, medium-, and low-pressure superheated steam are raised in the HRSG and sent to the steam turbine. High-pressure feedwater is also sent from the HRSG to the gasifier island, where it is used in the syngas cooler to raise high-pressure superheated steam, which is also sent to the steam turbine.

High-pressure superheated steam from the syngas cooler and the HRSG enters the steam turbine. Steam exhausted from the high-pressure turbine is reheated in the HRSG, expanded through the intermediate- and low-pressure turbines, and then condensed.

The power block will be equipped with a multicell wet evaporative mechanical draft cooling tower for the purpose of providing the cooling necessary to condense the steam that exhausts from the steam turbine. A water-cooled steam surface condenser will also be used, and the condensate will be collected in the hot well of the condenser and pumped back to the HRSG. Cooling water will be supplied to the surface condenser from the multicell cooling tower. See Section 1.4.2.3 for additional discussion of water supply and Section 1.4.2.4 regarding wastewater discharges.

1.3.3 PLANS FOR CONSTRUCTION, OPERATION AND TESTING

Figure 1.3-7 provides the basic schedule for the planned combined-cycle and proposed gasifier project. As shown, the first major activities relate to permitting and approvals. This includes the DOE NEPA process, of which this EIV is a part. Permitting also includes the FPSC need determination and licensing under the FEPPSA, as described previously. Overall, the permitting and approval process is expected to run through early 2007.

Overlapping slightly with the permitting and approval process is the next major activity, detailed design and engineering. The schedule allows approximately 1 year for this activity, which will be followed by facility construction. Construction of both the OGP and the related combined-cycle unit is expected to begin in late 2007.

The combined-cycle unit will be substantially complete by late 2009. The gasification island will be available to supply syngas in the first half of 2010. It is anticipated that the OGP demonstration period will begin in June 2010.

SCS/OUC will develop a test plan for the operation of the facility consistent with the objective of demonstrating the plant's commercial-scale capabilities. A 4-year demonstration phase is planned, during which the test program will focus on achieving reliable plant operation with high thermal efficiency, low operation and maintenance (O&M) costs and emissions, and a plant availability of at least 80 percent. Testing will involve plant measurements to improve the performance of all process equipment and develop a

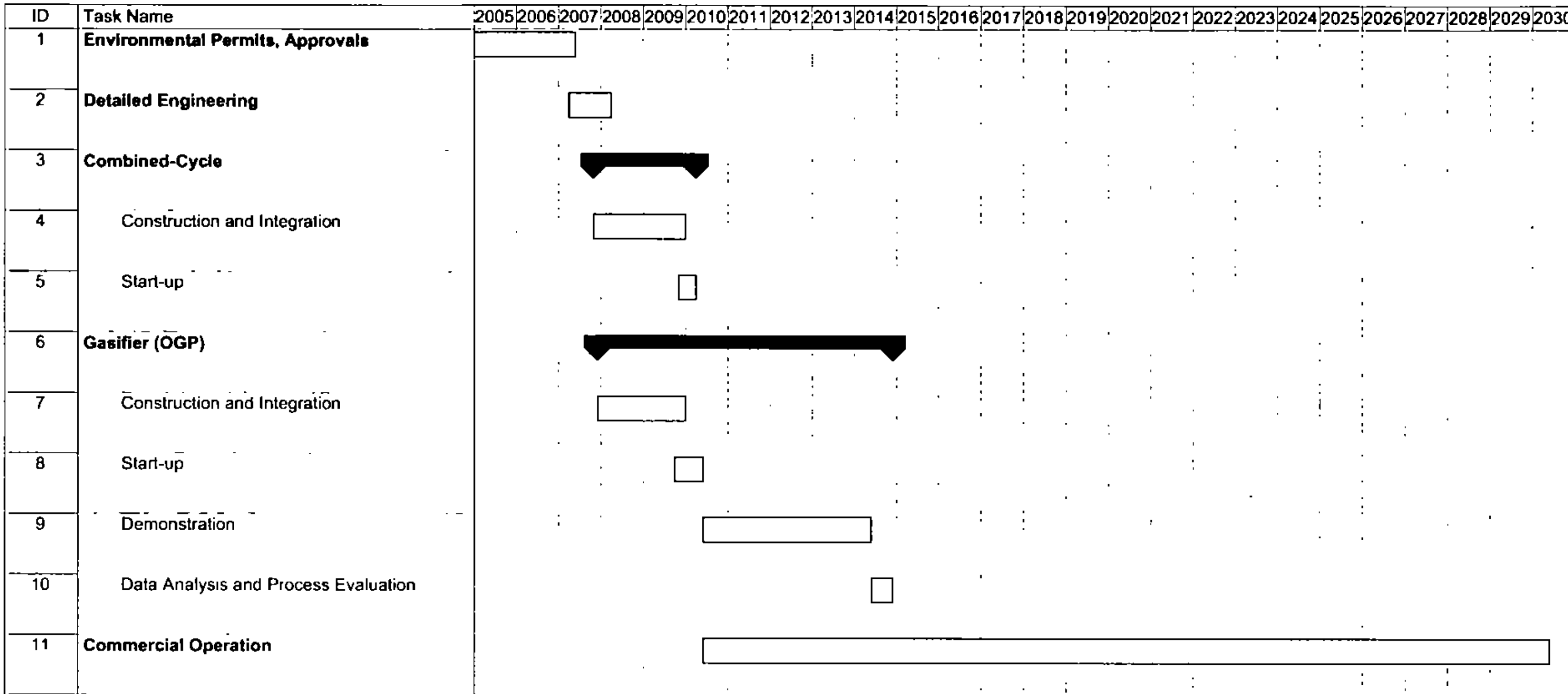
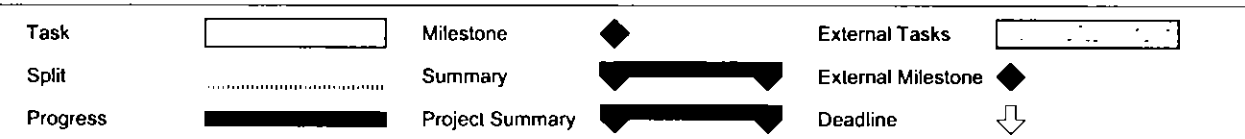


FIGURE 1.3-7.

BASIC SCHEDULE



Sources: SCS, 2005. ECT, 2005.

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deeper understanding of the Transport Gasification process. Various gas measurements will be performed, as will particulate measurements to determine HTHP filter particulate capture efficiency. The test program objectives may include the following:

- Optimizing gasifier performance.
- Monitoring equipment thermal and mechanical performance.
- Optimizing HTHP filter operational performance.
- Optimizing gas turbine syngas combustor performance.
- Monitoring gas turbine internals.
- Monitoring and optimizing HRSG performance.
- Optimizing and improving process control systems.
- Investigating the load-following capabilities of the unit.
- Improving startup and load-following capability.
- Evaluating the use of the gasification ash as a fuel source.
- Completing a full survey to characterize all the egress streams.
- Compiling plant repair and maintenance records.
- Completing thorough inspections of all plant equipment.

The combined-cycle unit will be operated under commercial dispatch. The test data for the gasifier project will be collected at these commercially representative conditions. The final equipment inspections will be made and the test results reported by the end of the demonstration phase.

1.4 DETAILED PROJECT DESCRIPTION

1.4.1 RESOURCE REQUIREMENTS

This section describes in detail the resource requirements for the proposed OGP and the related combined-cycle unit. The resources needed will be over and above those currently used by the existing units at Stanton. Table 1.4-1 presents a comparison of the resources that will be used by the OGP and the combined-cycle island with those currently used at the site.

Table 1.4-1. Comparison of Expected Operating Characteristics of the IGCC with Those of Existing Units

IN DRAFT

1.4.1.1 Energy Requirements

Upon completion of the gasification facilities, the new IGCC unit will operate primarily on syngas derived from coal. The combined-cycle unit (i.e., separate from the gasifier) will also be capable of operating on natural gas (both the CT and the HRSG duct burners). In addition to these fuels, the project and the combined-cycle unit will require electrical energy to run motors to power pumps, blowers, grinders, conveyor belts, and other machinery.

At full capacity, the gasifier island will consume approximately 137 ton/hr of coal. Assuming a design coal analysis of 8,760 Btu/lb, the energy input to the gasification plant will be approximately 2,400 MMBtu/hr at maximum continuous rated power production. Approximately two to three trains per week will be required to meet plant coal energy needs. Table 1.4-2 summarizes descriptive analytical parameters for the design coal. Table 1.4-3 presents the estimated composition of the syngas to be produced in the OGP gasifier. Figure 1.4-1 is an overall energy balance for the IGCC and shows a 40.5-percent efficiency of converting coal energy to electrical energy.

When operating on natural gas, the combined-cycle unit will consume approximately 2 million cubic feet (ft^3) of natural gas per hour operating at full load and with duct burners operating.

1.4.1.2 Land Requirements

With the exception of the electrical transmission line interconnection to the onsite substation, the proposed OGP and related combined-cycle facility will be constructed entirely within the 1,100-acre developed power plant site. The permanent IGCC facilities will be located in the graded area immediately south of existing Unit A. Figure 1.4-2 shows the currently expected layout of the new facilities relative to the existing facilities and the areas within the Stanton Energy Center site that will potentially be impacted by the OGP or the combined-cycle unit. Coal for the gasification island will be stored in a separate pile just north of the coal piles for Units 1 and 2. Figure 1.4-2 also shows the location within the existing landfill where gasification ash may be disposed (landfill disposal is

Table 1.4-2. Characteristics of Design Coal

	Minimum (%)	Maximum (%)
Proximate, as received		
Moisture	26.54	30.60
Ash	4.40	5.45
Volatile matter	30.25	31.73
Fixed carbon	32.91	37.10
Btu	8,300	8,884
Sulfur	0.20	0.40
Proximate, dry		
Ash	6.10	7.42
Volatile matter	42.80	45.32
Fixed carbon	47.42	51.10
Btu	11,942	12,127
Sulfur	0.28	0.55
Ultimate analysis, dry basis		
Carbon	69.90	71.17
Hydrogen	4.63	5.18
Nitrogen	0.88	1.10
Chlorine	0.01	0.01
Sulfur	0.28	0.55
Ash	6.10	7.42
Oxygen	14.69	17.02
Ultimate analysis, as received		
Moisture	26.54	30.60
Carbon	48.58	52.17
Hydrogen	3.24	3.76
Nitrogen	0.63	0.80
Chlorine	0.00	0.01
Sulfur	0.20	0.40
Ash	4.43	5.45
Oxygen	10.66	12.40

Source: SCS, 2005.

Table 1.4-3. Estimated Syngas Composition

Components	Normal Mole Percent	Normal Mole ppm
Major		
Methane	2.21	—
Carbon monoxide	23.74	—
Carbon dioxide	7.03	—
Hydrogen	12.05	—
Water	1.02	—
Nitrogen	53.93	—
Minor		
Carbonyl sulfide	—	1
Hydrogen cyanide	—	79
Hydrochloric acid	—	24
Hydrofluoric acid	—	0.4
Hydrogen sulfide	—	4
Ammonia	—	67
Lower heating value (Btu/scf)	—	125.7
Molecular weight	—	25.71

Source: SCS, 2005.

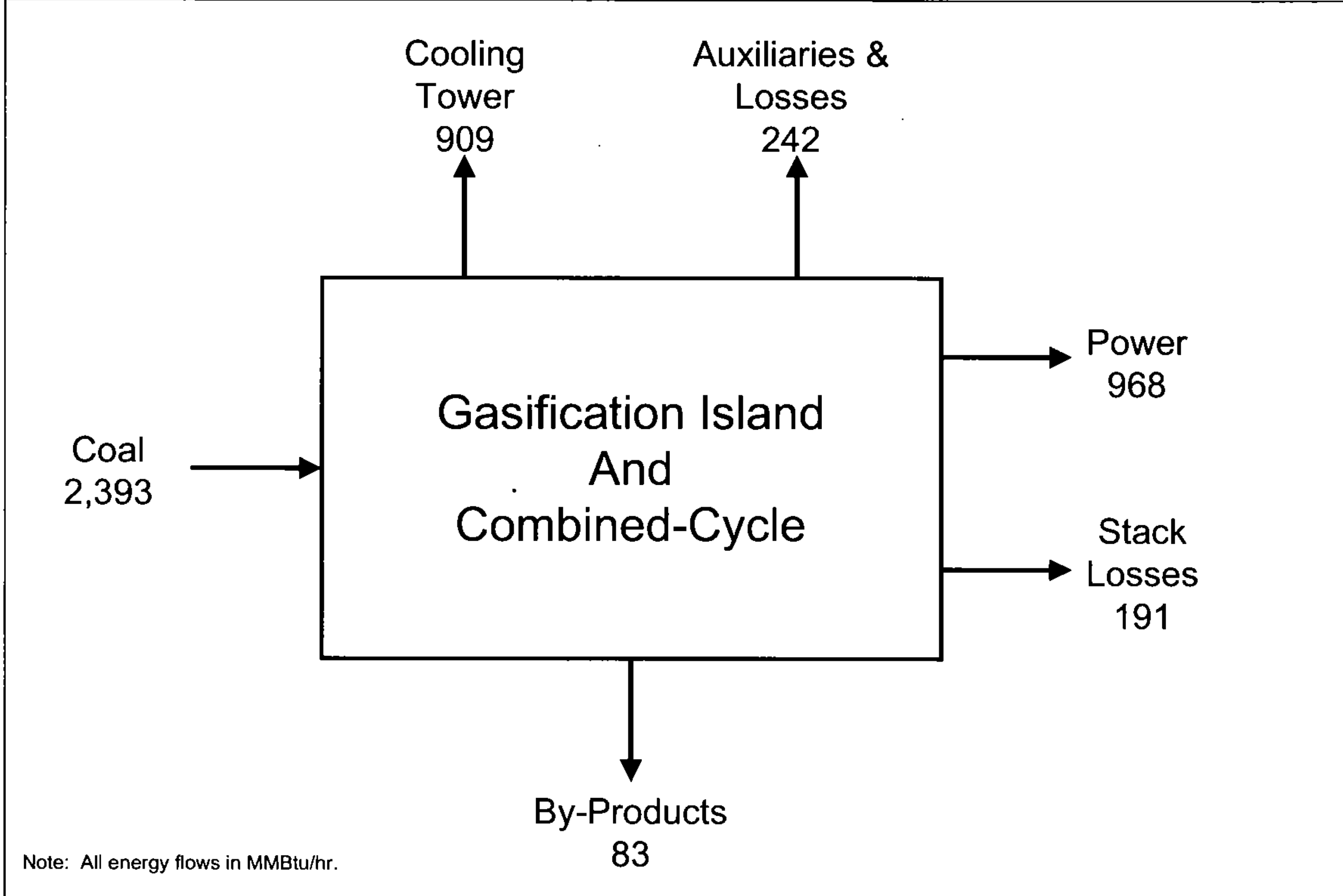

FIGURE 1.4-1.

OGP ENERGY BALANCE

Source: SCS, 2005.

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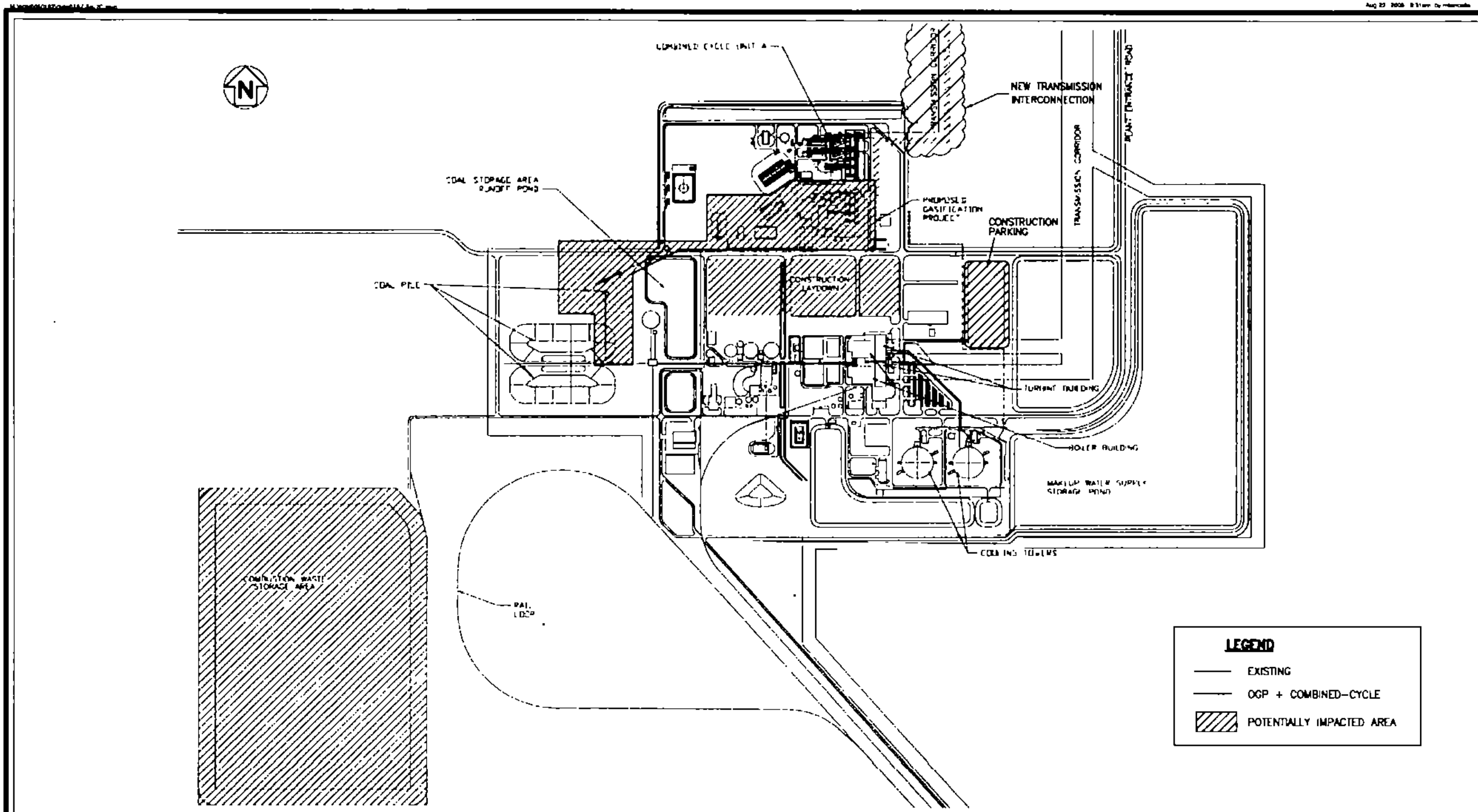

FIGURE 1.4-2.

BASIC LAYOUT AND AREAS IMPACTED

Source: SCS, 2005.

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one of three options, as discussed subsequently). Figure 1.4-3 provides a more detailed arrangement of the IGCC facilities.

The various temporary and permanent OGP and combined-cycle facilities will require land in the following approximate acreages:

Use	Temporary Area	Permanent Area
Construction laydown	20	
Construction parking	5	
IGCC facilities*		25 to 30
Coal pile		10
Ash landfill		25†

*Including transmission line interconnection.
†Over the 30-year project life, assuming 100-percent of ash landfilled and not reused.

As noted, the calculation used to estimate land area needed for ash disposal in the onsite landfill assumed all of the gasification ash would be disposed in this manner, as opposed to combusted in the Stanton PC units or trucked for reuse offsite.

OUC conducts volumetric surveys periodically to assess the rate at which the onsite landfill is used and the available space remaining for ash disposal. The onsite area designated as landfill is approximately 347 acres. According to OUC (2004) estimates, 3,911,000 cubic yards (yd^3) of waste material generated by Units 1 and 2 have been landfilled, using less than 7.5 percent of the available storage space. There are approximately 323 total available unused acres in the landfill.

After the addition of water, the approximately 18,300 lb/hr of gasification ash generated at the OGP would equate to 125,800 yd^3 per year requiring disposal. At this rate, over the assumed 30-year life of the project, the total amount of landfill space needed for OGP gasification ash would come to 25 acres. As a percentage of the available space, the OGP would require, as a maximum, approximately 8 percent.

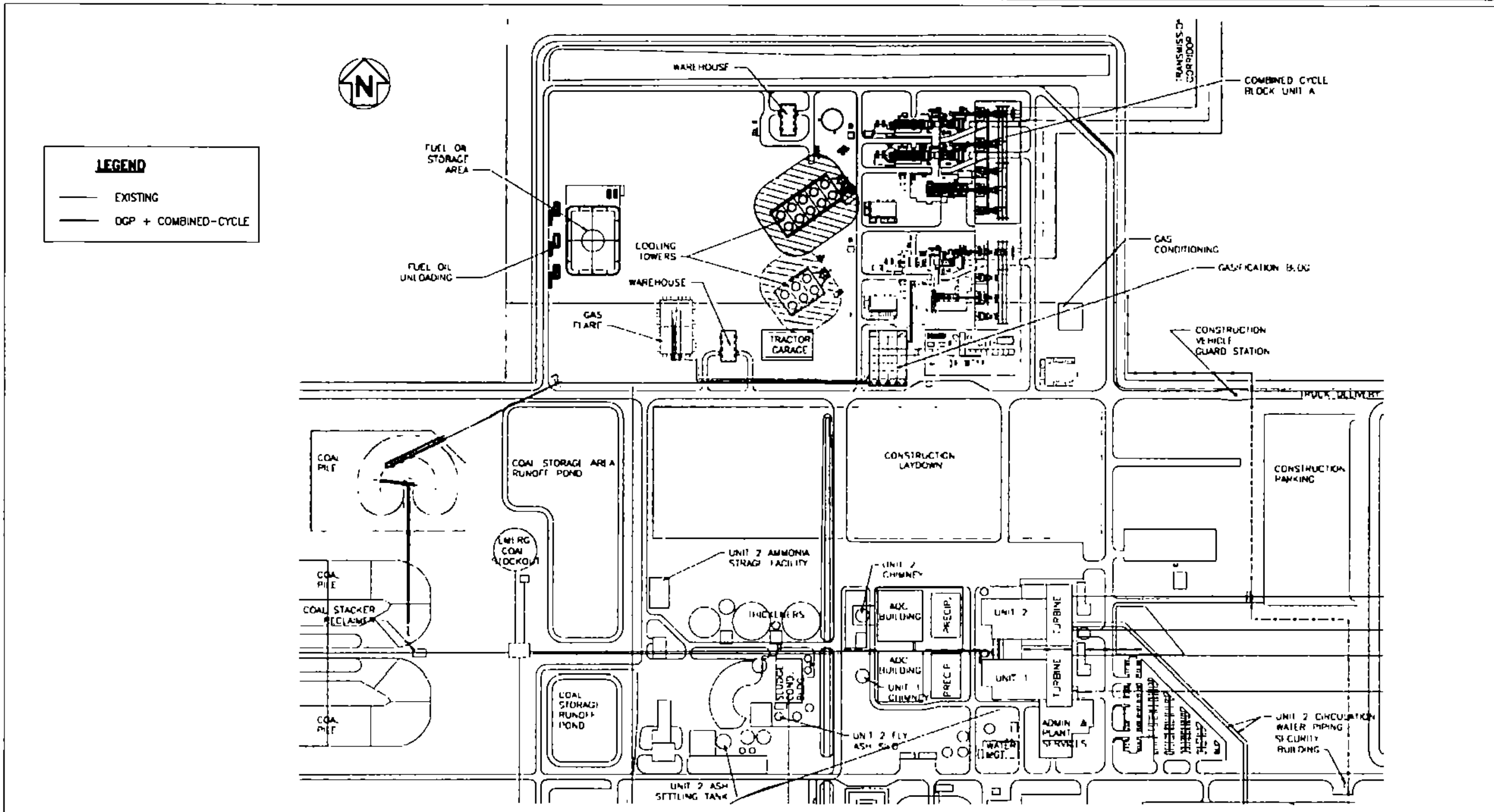

FIGURE 1.4-3.

DETAILED ARRANGEMENT

Source: SCS, 2005.

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The site will be graded for sheet flow runoff directed to existing retention ponds. Neither the OGP nor the planned combined-cycle unit will require any additional land for a new stormwater retention pond.

The Stanton Energy Center already has access to roadways and rail. Roadway access will also be improved by the Avalon Park Boulevard project (see Section 5.2). Neither the proposed OGP nor the planned combined-cycle unit will require any additional land for either road or rail access.

1.4.1.3 Construction Material and Equipment Required

The various types of construction materials that may be used for the OGP and the related combined-cycle plant are expected to be typical of other electric power facilities. Information presented is based on preliminary discussions with the potential contractors and suppliers of major equipment for the planned arrangement of the IGCC demonstration plant. The following list represents the estimated types and quantities of the most significant construction materials:

	OGP	Combined-Cycle
Concrete (yd^3)	12,179	9,172
Structural Steel (tons)	8,512	808
Pipe (linear ft)	112,862	27,000
Wire and cable (linear ft)	524,800	338,200

Other materials may be required in smaller quantities. Typical of these additional materials that will be used in this project are:

- For site work:
  - Fill materials (dirt, sand, gravel).
  - Piling.
  - Paving.
  - Linings.
  - Lumber.
- Paint.
- Architectural materials for buildings.
- Process equipment (gasifier, tanks, pumps, etc.).

- Electrical:
  - Conduit.
  - Switchgear.
  - Lighting.
  - Motor control centers.
  - Transformers.
- Instrumentation and control equipment, including the distributed control system.

The following work will either be done by SCS or contracts will be awarded for the following:

- Gasification system design and construction.
- Nitrogen plant design and construction.
- Combined-cycle plant construction.
- Other facilities' design and construction, including raw material receiving and storage systems.

Equipment used during construction will include that found at many large, industrial facility construction projects, as shown in Table 1.4-4.

1.4.1.4 Labor Requirements

Figure 1.4-4 shows the estimated construction workforce for the OGP and the related combined-cycle unit. Construction employment is expected to be highest from mid-2008 through mid-2009 because of the combined construction activities and needs associated with both the gasification and combined-cycle islands. Construction employment is expected to peak at approximately 600 to 700 workers for a 9-month duration and to average approximately 350 workers throughout the projected 28-month construction phase. Figure 1.4-4 shows needs for construction workers through mid-2010, as some construction laborers will be required through the gasifier startup process.

SCS/OUC will draw the construction workforce primarily from Orange County and the surrounding area. Only a limited number of construction workers are expected to temporarily relocate to the project area; therefore, potential impacts on housing, schools, and

Table 1.4-4. Anticipated Construction Equipment

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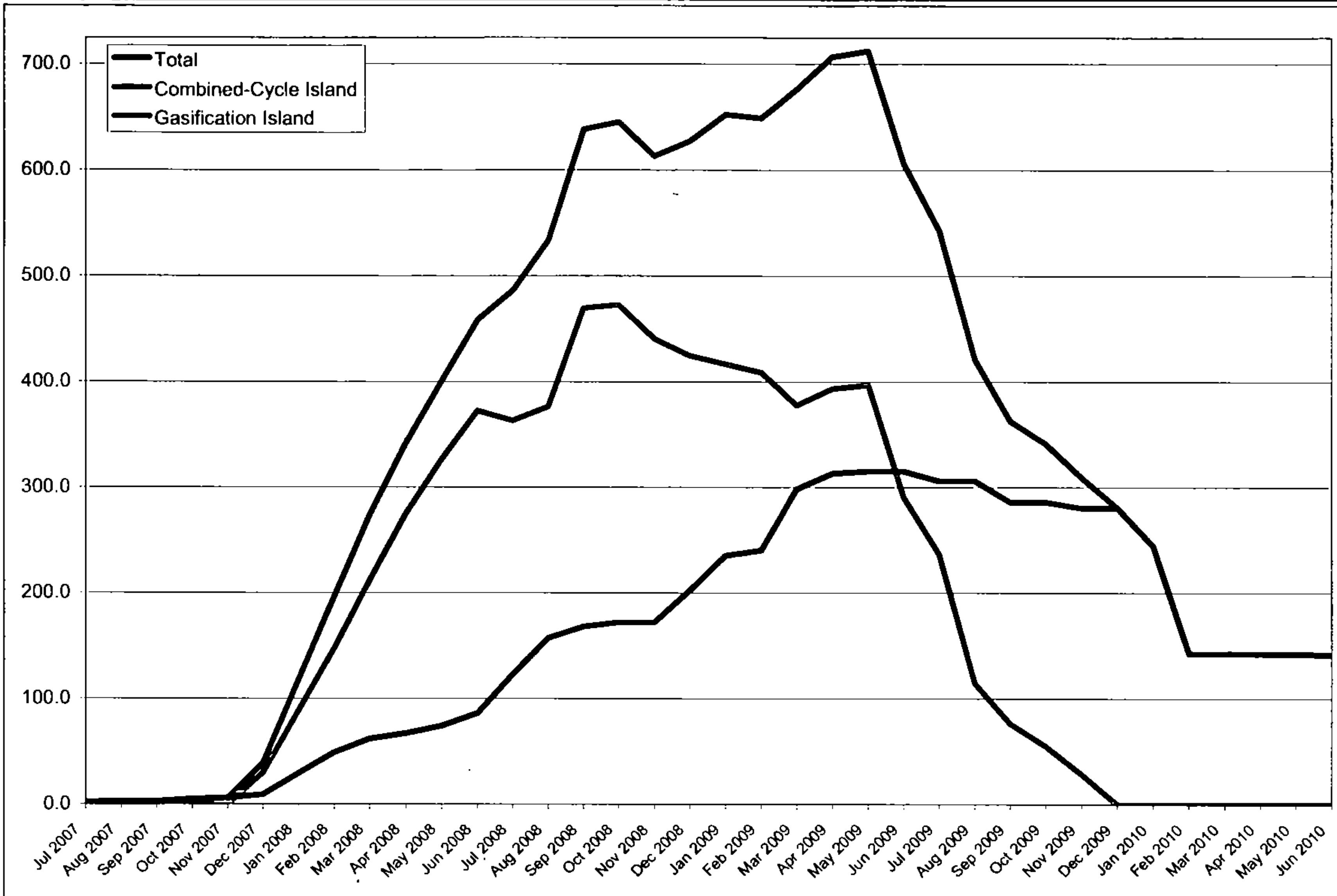

FIGURE 1.4-4.

CONSTRUCTION LABOR FORCE

Sources: SCS, 2005. ECT, 2005.

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other public facilities and services should be minimal (see Section 3.1.10 for further discussion). Most construction is expected to occur during daylight hours, with the majority of the construction workers being onsite between 7 a.m. and 5:30 p.m.

Staffing for the IGCC operations will vary between commissioning and postdemonstration. The operations staff will be assembled during the last 18 months of construction for training and to assist during the commissioning of the IGCC unit's equipment. This commissioning staff will consist of approximately 72 people added to the existing Stanton Energy Center personnel; 53 of these staff will be the long-term operations crew, with 19 people providing additional support during the commissioning and DOE demonstration phases of the project. After demonstration, only the 53-member long-term operations crew will remain for the life of the facilities. The facilities' life beyond 20 years will be based on economic analysis at that time. The combined-cycle unit is anticipated to operate at least 20 years. The gasifier operations staff will work two 12-hour shifts a day, with shift changes expected between 5:00 and 6:00 (both morning and evening). The night shift crew size should remain five to seven employees for the entire life of the project. The day shift crew size will range from 57 during the commissioning and DOE demonstration to 38 postdemonstration.

The majority of the operational workforce is anticipated to be drawn from the local labor pool in Orlando and Orange County, which will necessitate only minimal relocations. Given the location of the site in a major metropolitan area, the majority of employees are expected to reside locally. Based on the relatively small number of these employees, their associated trips to and from the site are not expected to create significant traffic impacts on the regional road networks. A few management personnel may be recruited from outside the region; however, this small number of potential relocations is not expected to create significant demands on regional housing, transportation facilities, or public services and facilities.

1.4.1.5 O&M Material Required

O&M material requirements are based on preliminary discussions with potential suppliers of major project components. These requirements are approximately as follows:

- Coal (for the gasifier) = 137 tons per hour.
- Natural gas (for the combined-cycle unit) = 2 million ft^3 per hour, operating at full load with duct burners.
- Water (primarily for cooling tower makeup) = 3.5 million gallons per day (MGD) maximum daily average.
- Process chemicals.

Additionally, small quantities of paints, degreasers, and lubricants will be consumed, as at any industrial facility.

1.4.2 ONSITE FACILITY REQUIREMENTS

1.4.2.1 Project Physical Appearance

Both the gasification island and the related combined-cycle unit will involve large, physical structures. The major structures and facilities will include the following:

- Gasification island:
  - Transport Gasifier air-blown gasifier.
  - Nitrogen plant.
  - Syngas cleanup system.
  - Particulate removal system.
  - Sulfur recovery system.
  - Ammonia recovery system.
  - Sour water system.
  - Ground-level flare.
  - Coal pile.
- Combined-cycle unit:
  - CT.
  - Steam turbine.
  - HRSG.
  - Cooling tower.

Figure 1.4-5 views the area of the Stanton site where the new IGCC facilities will be built, as it currently exists. Figure 1.4-6 illustrates the same area and includes the new combined-cycle unit, while Figure 1.4-7 adds the gasification island. Illustrations of multipoint flare system in-place at refineries, including a close-up of the system's multiple burners, were provided in Figure 1.3-5.

FIGURE 1.4-5.

CURRENT VIEW OF PLANNED IGCC FACILITIES AREA

Source: SCS, 2005.

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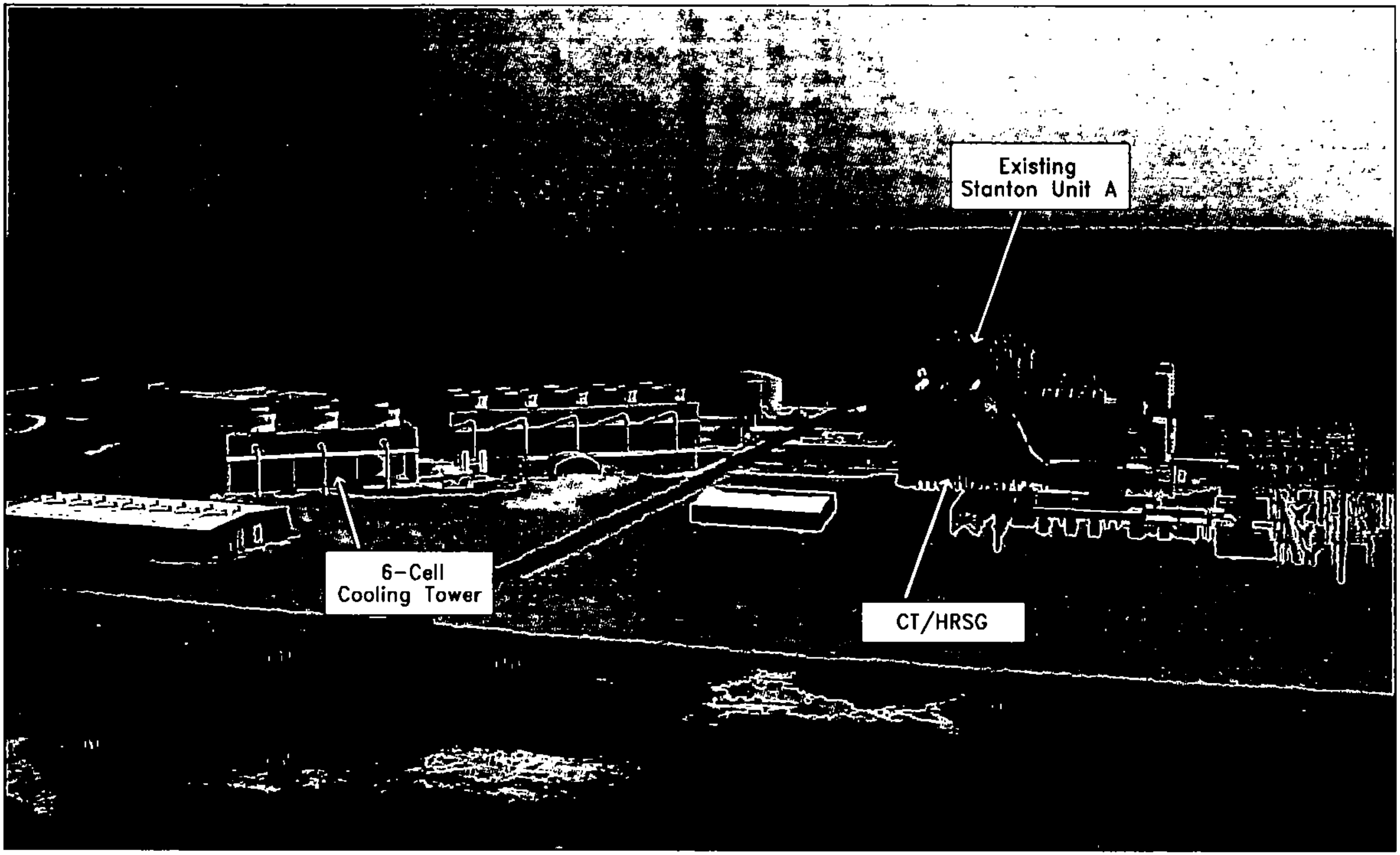

FIGURE 1.4-6.
RENDERING SHOWING ADDITION OF COMBINED-CYCLE ISLAND

Source: SCS, 2005.

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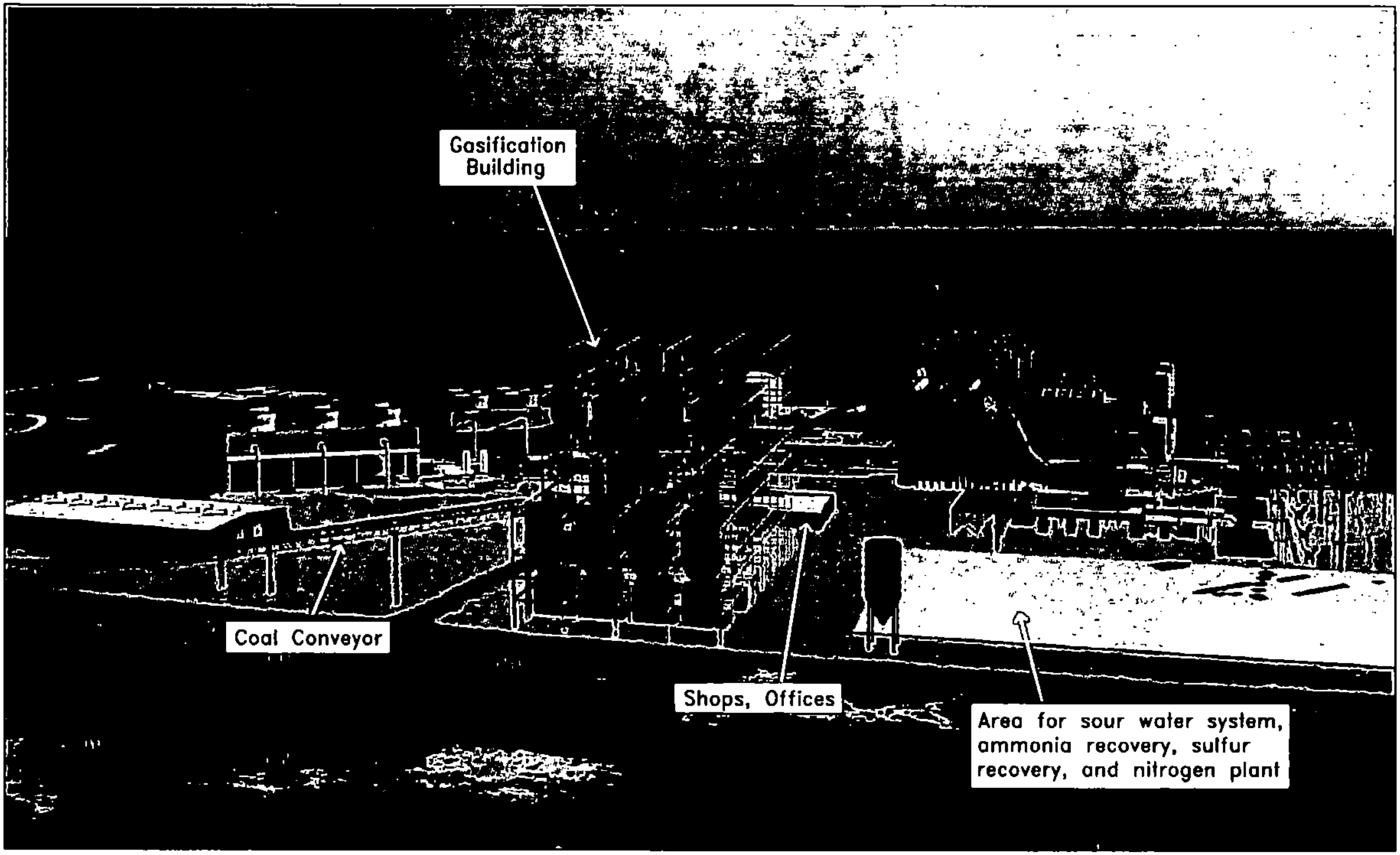

FIGURE 1.4-7.
RENDERING SHOWING ADDITION OF OGP GASIFICATION ISLAND

Source: SCS, 2005.

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The OGP and the combined-cycle unit will use other *existing* onsite facilities and equipment, including coal delivery, handling, and storage facilities; ash handling and storage facilities; water supply wells and treatment plant; cooling water pond; brine treatment facilities; industrial wastewater treatment facilities; and the electrical substation.

1.4.2.2 Fuel Storage and Handling

Coal will be delivered to the site by rail from sources in the western United States. Rail access to the Stanton Energy Center already exists, as do coal unloading and handling systems. Coal will be unloaded within the existing rail unloading building via bottom dump rail cars. As discussed previously in Section 1.3.2.1, from the unloading facilities, the coal will be conveyed, via closed conveyor, to the coal storage area. The coal storage area will be sized to provide fuel for approximately 45 days of operation. Also, the coal storage area will be lined with a synthetic liner and will use the existing leachate and stormwater runoff collection systems and a retention basin to prevent ground water seepage and runoff from the area.

Natural gas used for IGCC startup and fired in the CT and duct burners during periods when the gasifier is not operating will be obtained from the existing onsite pipeline that serves Unit A. Natural gas will not be stored on the site.

1.4.2.3 Water Supply

The OGP and the combined-cycle unit will obtain all of their water for operations from existing onsite Stanton systems. The principal sources of water at Stanton are treated effluent from the nearby Eastern Water Reclamation Facility and ground water from onsite wells. The addition of the IGCC unit at Stanton will require a somewhat greater supply of treated effluent. OUC is working with Orange County on an updated reclaimed water supply agreement. A small amount of additional ground water will be needed for demineralized water, evaporative cooler makeup, and potable use, but the additional amounts withdrawn from onsite wells will be within existing Stanton permit limits.

OGP and related combined-cycle unit water use is described in Figures 1.4-8 and 1.4-9 and Table 1.4-5. (The table provides the flow quantities for the numbered streams shown in the two figures.) On an annual average basis, approximately 2.6 MGD of treated effluent will be drawn from the onsite storage pond. On a short-term basis, water use can change, due to changes in ambient temperature and/or relative humidity, both of which affect consumption of water. Other variables that impact water use are plant load and cooling tower cycles of concentration. Highlights related to water supply requirements from the water balance diagrams include:

- Cooling tower makeup from onsite pond—2.6 MGD.
- Demineralized water from existing Stanton plant—0.14 MGD (from onsite wells).*
- Water for evaporative coolers—0.04 MGD.*
- Potable water—0.6 gpm.*

  *From onsite wells.

The largest need for water will be the circulating (cooling) water system. More than 80 percent of the cooling system demand is related to the combined-cycle unit's operation, while less than 20 percent is attributable to the OGP gasification processes. Makeup water must be supplied to this system to replace cooling tower evaporative losses and *blowdown*. Blowdown is water discharged from the system to maintain water quality in the cooling tower at levels necessary for the system's proper functioning. One of Stanton Energy Center's prominent features is the use of treated effluent to supply the makeup to cooling systems, thereby recycling this water and displacing the need for higher quality water. Water quality data for the makeup supply storage pond are provided in Table 2.3-7 (page 2-51). Noncooling water requirements will include makeup to the HRSG, makeup to the CT evaporative cooler, and potable water.

The cooling water will circulate through a counter-flow, mechanical draft cooling tower that uses electric motor-driven fans to move the air in a direction opposite to the flow of the cooling water. The heat removed in the condenser will be discharged to the atmosphere by heating the air and through evaporation of some of the cooling water.

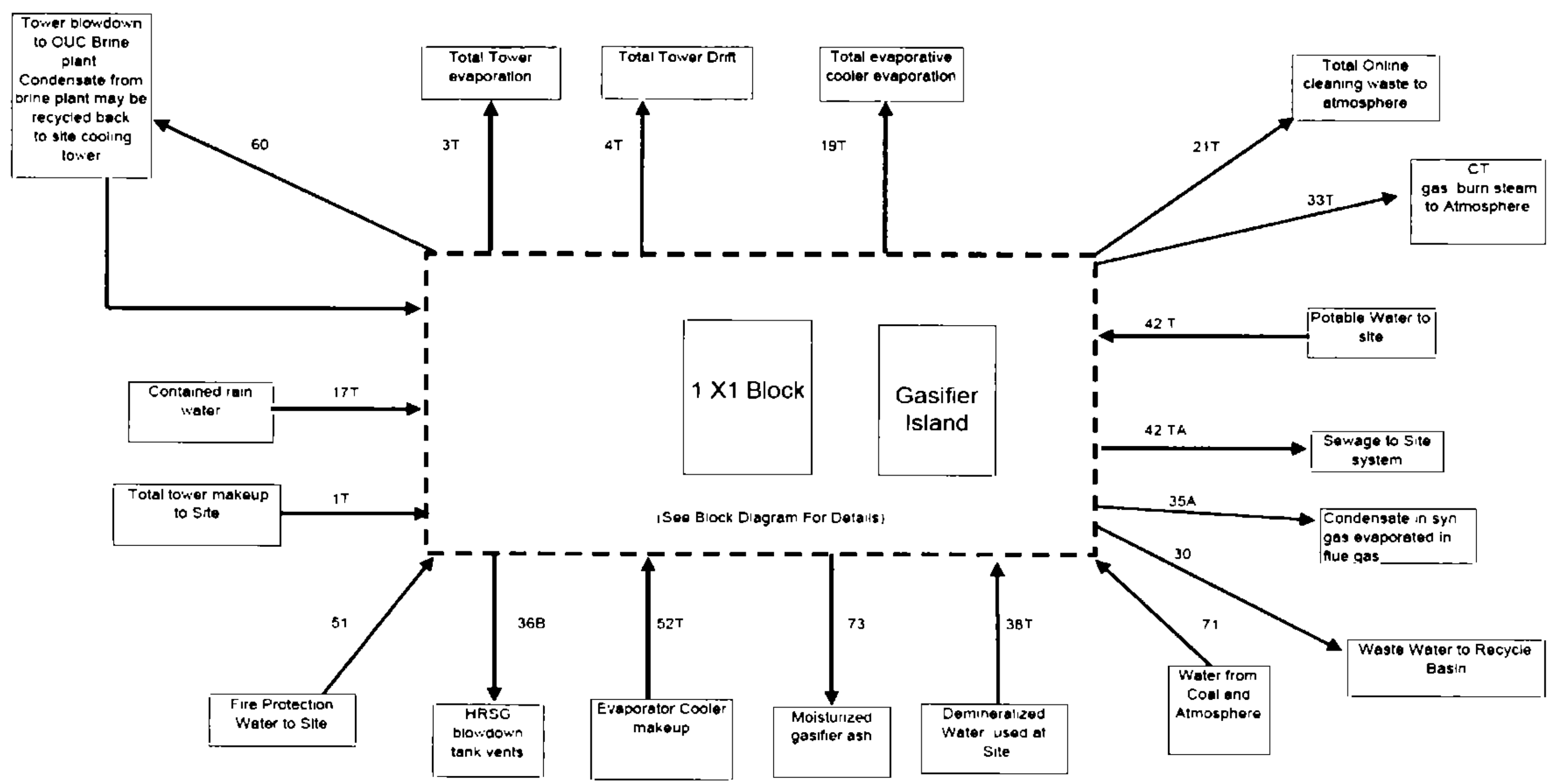


FIGURE 1.4-8.

SIMPLIFIED OGP WATER BALANCE DIAGRAM

Source: SCS, 2005.

Environmental Consulting & Technology, Inc.

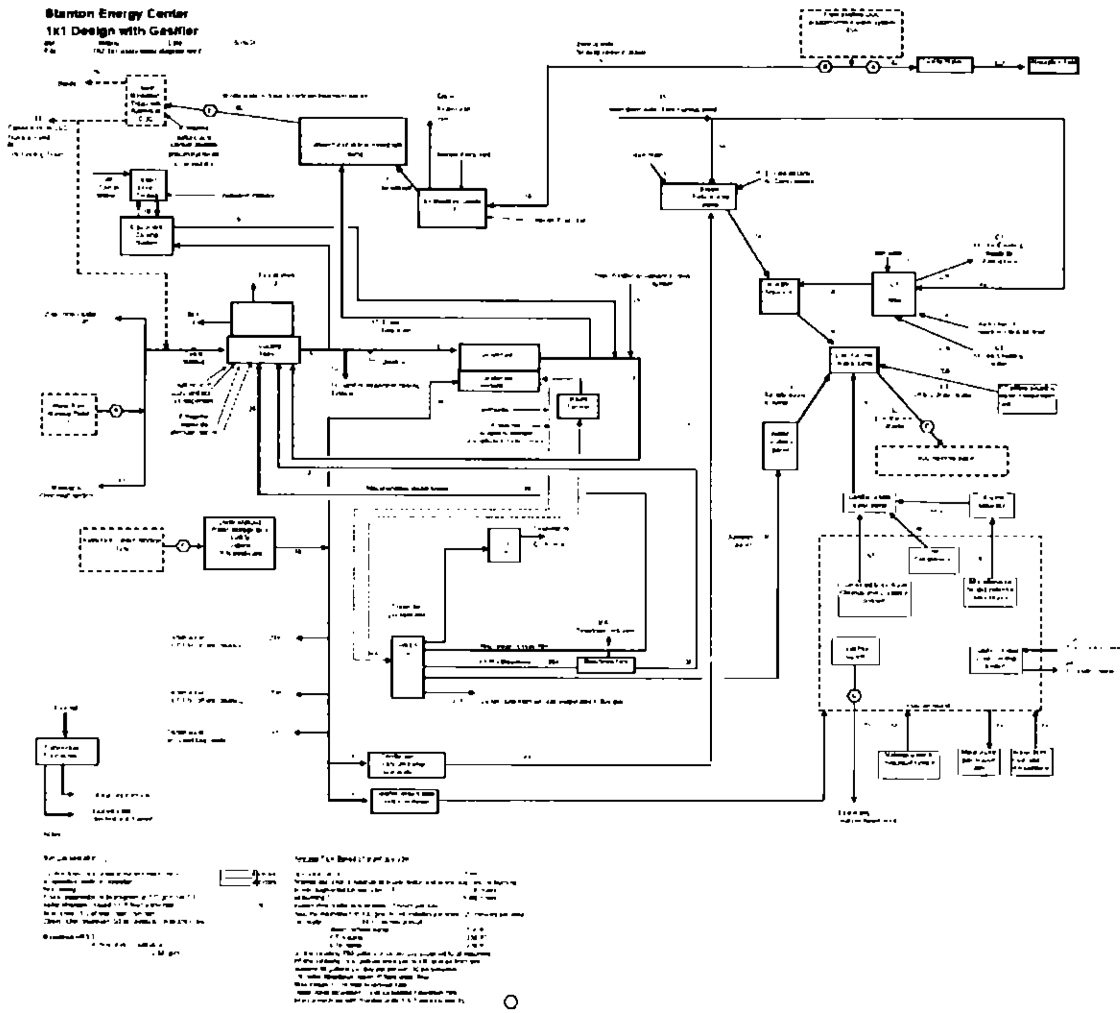


FIGURE 1.4-9.

DETAILED WATER BALANCE DIAGRAM

Source SCS 2004

Environmental Consulting & Technology, Inc.

Table 1.4-5. Water and Wastewater Stream Flow Rates

IN DRAFT

A chemical feed system will supply water conditioning chemicals to the cooling tower basin to minimize corrosion and control the formation of mineral scale and biofouling. Sulfuric acid will be fed into the circulating water system in proportion to makeup water flow for alkalinity reduction to control the scaling tendency of the circulating water within an acceptable range.

To prevent biofouling in the circulating water system, gaseous chlorine will be fed continuously into the system as the primary biocide. A secondary biocide (algaecide) will be fed as needed. Other chemicals likely to be used in the cooling water system include a silt dispersant and an iron dispersant (if Stanton wastewater treatment plant effluent water is included in the makeup supply).

Demineralized water will be needed as makeup to the steam cycle to replace HRSG blowdown and steam losses. Demineralized water for the OGP and the related combined-cycle unit will be supplied from the existing Stanton system.

1.4.2.4 <u>Wastewater Discharge</u>

During operation, the OGP and the combined-cycle unit systems will produce various process wastewaters, all of which will be discharged to the existing Stanton treatment and reuse systems. No process waste streams or water treatment discharges will be released offsite. The principal wastewater streams will originate with the combined-cycle unit and will consist of cooling tower blowdown and low-volume wastes. Process wastewater containing oils will be collected in an oily wastewater sump, where an oil/water separator will remove the oil. All treated wastewater and blowdown from the cooling tower will be discharged to the onsite systems. Highlights related to wastewater discharges from the water balance diagrams include:

- Cooling tower blowdown to Stanton wastewater treatment plant—0.33 MGD.
- Low-volume wastes to Stanton recycle basin—0.18 MGD.

The chemical feed area drains will collect spillage, tank overflows, and liquid from area washdowns. The collected chemical drain effluent will be routed to the waste neutralization system for pH adjustment.

Stormwater will be routed via sheet flow to culverts and directed to existing, onsite stormwater retention ponds.

Chemical cleaning wastes will be generated from the periodic cleaning of the HRSGs. These wastes will consist of alkaline and acidic cleaning solutions used for chemical cleaning of the HRSGs after the units are put into service, and for turbine wash and HRSG fireside wash waters. These wastes generally contain high concentrations of heavy metals. Chemical cleaning services will be conducted by outside contractors who will be responsible for removal of their waste products from the site.

1.4.2.5 Solid Waste/By-Product Storage, Disposal, and/or Use

The primary solid wastes or by-products produced by the gasification and gas cleanup systems of the OGP are gasification ash, elemental sulfur, and anhydrous ammonia. As discussed previously, ash is formed in the gasifier and results from the accumulation of noncombustible mineral material originally present in the coal and unreacted carbon. Further discussion of options for reusing or disposing of gasification ash is provided in Section 1.4.4.3, which also addresses disposition of sulfur and ammonia.

The principal potential onsite impact associated with solid waste/by-product disposal would be landfilling the gasification ash in the existing Stanton landfill.

Other low-volume solid wastes generated by the OGP unit include solids from water and wastewater treatment systems (e.g., sour water treatment), demineralizer resin beds, air filter replacement, and general office wastes. The nonhazardous wastes will be disposed offsite in permitted landfills in the region. Any waste determined to be hazardous under the Resource Conservation and Recovery Act (RCRA) regulations will be transported offsite by a licensed contractor to a RCRA-permitted treatment and disposal facility or provided to the manufacturer for treatment and recycling.

1.4.2.6 Drainage and Runoff

Stormwater runoff from the OGP and combined-cycle facilities will be controlled, treated, and managed in accordance with existing, approved plans for the Stanton Energy Center and in compliance with applicable federal, state, and local requirements. Runoff from areas associated with industrial activity, including the coal storage areas, and equipment and floor drains will be routed to the recycle basin. This system includes pH adjustment, oil separation, and suspended solids removal. Treated wastewater from this system will be discharged to the recycle basin for reuse.

1.4.3 NEEDS FOR TRANSPORTATION RESOURCES AND OTHER OFFSITE RESOURCES AND INFRASTRUCTURE

1.4.3.1 Transportation Access

Neither the OGP nor the planned combined-cycle unit will require additional transportation resources or infrastructure. Existing road access to the Stanton site (via Alafaya Trail) will be adequate to support both construction and operation of the OGP and the combined-cycle unit (see Section 3.1.11). Furthermore, as discussed in Section 5.2, the project to improve traffic flows in the immediate area by extending Avalon Park Boulevard south from Alafaya Trail is anticipated to be completed by the end of 2008.

1.4.3.2 Fuel Delivery

The existing rail access to the site will also adequately serve the OGP needs for coal without improvement. To supply Stanton Units 1 and 2, five trains typically unload coal to the facility per week. The OGP will require an additional two to three trainloads of coal per week to supply the gasification island. The OGP will be served by three railcar sets. OUC will contract with CSX for coal delivery. Coal from the Powder River Basin (western United States) will be delivered by CSX and the Burlington Northern-Santa Fe (BNSF) Railroad, through a separate contract with CSX, to the Stanton Energy Center and OGP.

An existing pipeline delivers natural gas to the Stanton site (used primarily in Unit A). This pipeline is capable of supplying gas to the planned combined-cycle unit operating at full load on gas. No upgrades or significant modifications to the existing natural gas supply facilities will be needed for OGP or the combined-cycle unit.

1.4.3.3 Electrical Transmission

At this time the only transmission facilities known to be required to support the planned combined-cycle unit are the interconnection from the combined-cycle unit to the existing, onsite substation, which is located approximately 3,000 ft northeast of where the new unit will be constructed. This transmission corridor could take several forms, but is likely to parallel an existing line by crossing up to approximately 5 acres of undeveloped buffer area.

1.4.4 OUTPUTS, DISCHARGES, WASTES, AND BY-PRODUCTS

1.4.4.1 Air Emissions and Odors

Types of Air Emissions

The sources of air emissions during the operation of the OGP and the related combined-cycle unit may be broadly categorized as follows:

- Fugitive emissions from material handling and storage.
- Particulate emissions from discrete material transfer points.
- Flare emissions.
- Stack emissions.
- Particulate emissions contained in drift (mist) from the mechanical draft cooling tower.

The types of emissions associated with these sources are described in the following paragraphs.

Material handling and storage will generate fugitive particulate emissions. The principal materials being handled are coal and gasification ash for the OGP. For coal handling, the dust control system involves a combination of controls, including rail car unloading in the existing enclosed building, enclosure of certain coal conveyors, and baghouse particulate control at key transfer points.

The existing Stanton coal conveying system is equipped with water spraying controls that will be used to minimize fugitive particulate emissions when transferring PRB coal. Gasification ash will be wetted to reduce potential fugitive dust emissions during handling.

Fugitive emissions of gaseous-phase compounds may be generated within the gasification island. The potential sources will be leaks from equipment such as valves, compressor seals, and flanges. These emissions will be minimized by good O&M practices. In addition, area gas detectors will be used to alert plant staff of fugitive gas emissions.

The primary source of emissions in the IGCC unit results from the combustion of syngas in the CT. The exhaust gas goes to the atmosphere via the HRSG stack. Emissions from the HRSG stack are primarily NO_x, SO_2, CO, PM, and other trace constituents. Stack emissions will reflect emission rates consistent with best available control technology (BACT) determinations. Similar constituents will be emitted from the CT (and duct burners) when firing natural gas.

The flare for the OGP will normally have only minimal emissions associated with the natural gas-fired pilot flame. Higher emission rates will occur during startup and shutdown of the IGCC unit and during facility upsets.

Quantity of Air Emissions

Based on detailed project design, it will be possible to quantify the expected emissions from the material handling activities. Until that time, however, some general conclusions can be drawn based on the operating conditions.

The first consideration is limitation of particulate emissions from material handling equipment. Measures to reduce fugitive emissions from the coal and gasification ash handling systems have been incorporated into the design of the system. For example, coal and ash conveyors will be enclosed.

A second consideration for the limitation of fugitive emissions is the moist climate. High humidity tends to suppress fugitive emissions, not only from the material itself, but also from the equipment operation on the roads. Because rain occurs frequently (averaging every other day during the summer months), uncovered coal at the storage site will maintain a high degree of moisture until conveyed for processing.

A third consideration is the infrequency of high winds in the area. High winds would tend to increase greatly wind-blown fugitive emissions.

The combination of these factors should enhance the ability of the operators to limit the fugitive emissions, although they cannot be eliminated.

Estimating potential emissions from equipment leaks depends on design and operational factors. For example, emissions from equipment leaks depend on the types and numbers of equipment involved and the frequency with which the equipment is inspected and repaired, among other factors. Emissions estimates will be developed as more detailed design information becomes available.

Preliminary estimates of emissions from the CT/HRSG stack are shown in Table 1.4-6. These preliminary estimates are based in part on the best information available at the time of EIV preparation and best engineering judgment. Since detailed design of neither the OGP nor the related combined-cycle unit has been performed, these estimates do contain some amount of uncertainty. Where possible, emission rates have been estimated using vendor guarantees based only on theoretical calculations using expected syngas compositions (not based on combustion testing of syngas). Emission factors included in published test reports from other IGCC projects have also been used. The rates presented and evaluated in this EIV assume no postcombustion controls (i.e., no SCR or CO catalyst). Only removal efficiencies gained through expected syngas cleanup systems have been assumed

Table 1.4-6. Preliminary Estimates of Air Pollutant Emissions from CT/HRSG Stack

IN DRAFT

in these estimates. The PSD permitting process for the OGP and the related combined-cycle unit will eventually determine the levels of control and allowable emission rates, which may be lower than those evaluated in this EIV. The parameters shown in this table generally represent maximum anticipated emissions and, as such, should provide conservative estimates for purposes of modeling air impacts. It is noted that emissions and emissions impacts will vary with unit load, ambient conditions, and other factors. Emissions information for other operating scenarios are not yet available, but will be developed for evaluation in the licensing/permitting process.

Another source of air pollutant emissions will be the OGP flare. As indicated previously, the flare will be employed to combust syngas during gasifier startup/shutdown and plant upsets. Under normal operations of the OGP (i.e., all syngas produced by the OGP routed to the combined-cycle unit), the only emissions from the flare will be the result of combusting natural gas in eight pilots. These pilots will be on at all times.

During startup, natural gas-fired startup burners are used to heat the gasifier to a point where coal combustion can begin. Once the gasifier reaches the necessary temperature, coal feed begins, and the temperature is increased. From the initial startup to this time, the atmosphere in the gasifier is oxidizing, and the gas produced has no heating value (flue gas). Therefore, if the gas were sent to the flare, natural gas would have to be added to produce a combustible mixture. So instead, the flue gas exhaust will be vented to the startup stack.

Once the gasifier is at the proper temperature, the airflow is reduced until the atmosphere in the gasifier is reducing. At that point, the coal is being gasified and syngas is being produced. Initially, the flow of syngas will be insufficient to send to the gas turbine, so it will be sent to the flare and burned. Varying amounts of syngas will be combusted by the flare as the syngas production of the gasifier is increased. When the gasification island reaches a syngas production level at which it can support the operation of the gas turbine, the syngas will be diverted from the flare to the gas turbine.

The length of time of this entire startup sequence will vary based on a number of factors, including the starting temperature of the gasifier. During a cold start of the gasifier, it is expected it may take up to 24 hours to begin sending syngas to the gas turbine due to the length of time required to heat the gasifier refractory. This would include approximately 17 hours of exhausting flue gas through the startup stack and approximately 7 hours of combusting syngas in the flare.

In the event of process upsets of either the OGP or the combined-cycle unit, syngas may also be routed to the flare for combustion. During such events, the duration of syngas combustion will vary depending upon the type of upset.

Prior to being exhausted through the startup stack or burned by the flare, both the flue gas and syngas will go through the gas clean-up process of the OGP.

Odors

Some odors will be emitted during construction and operation of the OGP and the planned combined-cycle unit that may be detectable or noticeable onsite. Sources for these odors may include the following:

- Diesel engine exhaust from locomotives, trucks, construction equipment, and coal yard loaders.
- Coal pile and coal handling.
- Sulfur storage and handling.
- Ammonia storage and handling.

Any potential odors emitted from the operations should be limited to the immediate site area and should not affect offsite areas.

1.4.4.2 Wastewater Treatment and Effluents

Wastewater treatment and effluents were discussed in Section 1.4.2.4.

1.4.4.3 Solid Wastes/By-Products

OGP (Gasification Island)

As discussed previously, there will be three principal by-products of the gasification process: gasification ash, sulfur, and ammonia. Reuse or disposal of each of these by-products is discussed in the following paragraphs.

Gasification Ash

Gasification ash (coal ash and unreacted carbon) is removed from the HTHP filters and gasifier. Gasification ash is not considered hazardous, and disposal requirements would be similar to those experienced for fly ash from conventional boilers. Treatment of the gasification ash will include wetting it to minimize dust emissions. The OGP process will produce approximately 18,300 lb/hr of gasification ash. Gasification ash will be stored in an atmospheric silo as it is generated. Prior to transferring, the ash is mixed with water in a pug mill to minimize dust emissions.

The three options for management of this ash are as follows:

- Combining the gasification ash with the coal entering OUC's PC units and combusting it.
- Sending the gasification ash to the onsite landfill.
- Utilizing the gasification ash in other processes.

Each of these options is discussed further in the following subsections.

Combusting the Gasification Ash in OUC's PC Units—The projected coal to carbon conversion of 97 percent results in the gasifier ash having a higher heating value of approximately 4,000 Btu/lb. Although this material is sufficiently rich in carbon to be combusted, economic evaluation reveals that the total energy content is insufficient to justify the cost of a dedicated combustion system. However, the gasifier ash may be combusted in one of the existing Stanton PC units. As the amount of gasifier ash combusted would be low relative to the quantity of coal combusted in the PC boilers, it would not be expected to affect either disposal requirements or utilization applications of the PC combustion ash. The gasification ash leaving the process is a fine powder in the range of 15 to 20 micrometers (μm). On a dry basis, gasification ash will have the following composition:

Proximate Analysis	Wt%
Volatiles	10.32
Fixed carbon	24.87
Ash	64.59
Sulfur	0.22

Ultimate Analysis	Wt%
Carbon	33.06
Hydrogen	0.36
Nitrogen	0.21
Oxygen	1.56
Sulfur	0.22
Ash	64.59

Ash Mineral As Oxide	Wt%
Silicon dioxide	39.72
Aluminum oxide	13.90
Calcium oxide	27.82
Magnesium oxide	9.35
Sodium monoxide	1.34
Potassium monoxide	0.77
Iron oxide	5.15
Titanium dioxide	1.13
Phosphorus pentoxide	0.83

Note: Wt% = weight percent.

Water will be added to the gasification ash at a rate of 0.94 pound of water per pound of dry ash to moisten the ash and minimize dust emissions. After wetting the gasification ash, it would have an as-received moisture content of 48.5 percent and heating value of approximately 2,000 Btu/lb.

Based on approximately 900 MW of total capacity and a coal-to-busbar efficiency of 35 percent, the coal feed rate into the existing units based on the average coal is approximately 700,000 lb/hr. The addition of the gasification ash would reduce the coal feed rate by approximately 7,000 lb/hr (or 1 percent) to 693,000 lb/hr.

Assuming the gasification ash would be used in the PC units, the gasification ash would be pneumatically conveyed to one of the units.

Disposal in Onsite Landfill—A study was conducted with gasification ash samples from the Transport Gasifier at the PSDF to evaluate disposal and utilization options. The following technical points were addressed:

- Necessary handling and processing steps prior to disposal and utilization.
- Technical and environmental issues associated with the disposal of gasifier ash.

Southern Company and OUC have extensive experience in handling solids from PC plants. Although the ash produced in a Transport Gasifier differs from PC ash in carbon content and surface area, the equipment used for handling the two materials is the same.

The primary issue regarding ash conditioning for disposal is dust control. Wetting of the gasification ash was demonstrated in a turbine blender without the need for surfactants. The water requirements for wetting were higher than for PC ash, but the end product was easily handled and compacted well for disposal. Wetting did not release excessive heat, so heat dissipation will not be required. Liner tests did not reveal any incompatibility with either clay or synthetic liners. It was concluded that the gasification ash disposal characteristics are similar to those of coal ash from PC boilers. Therefore, based on all current information, disposal of the gasification ash in the existing onsite landfill (designed to state specifications) appears to be an option.

Test results indicate that Transport Gasifier ash meets all regulatory requirements defining nonhazardous materials: toxicity, ignitability, corrosivity, and reactivity. These results indicate the gasification ash would not be classified as hazardous, and disposal requirements would be similar to those experienced for fly ash from conventional boilers. The calcium sulfide levels in the gasification ash had no adverse impact on waste disposal in terms of toxicity, ignitability, reactivity, or corrosivity.

Material conditioning by mixing with water in a pug mill prior to landfilling would be required mainly for convenience and then most likely for dust control. In general, the disposal requirements of gasification ash should be no more rigorous than that currently experienced with conventional fly ash, and no significant waste treatment prior to disposal is expected.

Other Reuse of Gasification Ash—If combusting the gasification ash in a PC unit is not viable, it may also be feasible to market the ash to reduce the amount sent to the onsite landfill. Support programs have identified potential by-product applications. Utilizing gasification ash holds promise, although some market development would be required. Gasification ash has been evaluated for several possible uses, including a precursor for activated carbon and as a cement industry fuel source. Note that to proceed with utilizing gasification ash as either an activated carbon or a cement kiln fuel, development of a specific market would be needed.

Evaluation as an activated carbon source revealed that raw gasification ash approaches the characteristics of commercial carbons. Potential use for higher-grade activated carbon is possible following beneficiation by chemical activation and acid washing. Commercial feasibility may depend on market growth to include new applications such as flue gas mercury emissions control.

Due to the expanding market for activated carbons, especially in applications related to environmental protection such as air and water purification, new precursors are being sought. Compared to the conventional two-step process that includes a devolatilization of the raw materials followed by an activation step, gasification ash only requires a one-step activation process since it has already gone through a devolitalization process in the gasifier. The added value generated from the utilization of the gasification ash could generate additional revenues.

An evaluation of the use of gasification ash as a fuel source for cement processors was also conducted, and it was found that the ash could be mixed with the raw material in a cement kiln. Cement industry contacts have expressed some preliminary interest in using the ash as a kiln feedstock material. However, the cost and handling issues have yet to be evaluated.

Offsite reuse of the gasification ash would require transport. If by truck, approximately 160 truckloads per week would need to be transported. Given this number of truckloads, transport by rail would be investigated as an alternative.

Sulfur

The OGP gas cleanup system will produce approximately 760 lb/hr of 99-percent pure elemental sulfur. This sulfur by-product is also expected to be of marketable-grade quality and have commercial uses. Assuming a commercial market, the sulfur will be transported offsite by truck or rail and sold. The sulfur is removed from the process and stored as a solid in an atmospheric silo that is adjacent to the gasification island. Based on the amount of sulfur in the design coal, and assuming it is shipped as a solid, the quantities produced would correspond to three trucks of sulfur per week. Onsite sulfur storage systems will have the capacity to store up to 30 days of sulfur from the recovery system. If no market is found, the sulfur will be landfilled onsite.

Ammonia

Anhydrous ammonia (99.7-percent grade) will be produced as a byproduct of the gasification process at a rate of approximately 1,960 lb/hr. As the ammonia is produced, it is stored in a tank located near the gasification island. The onsite SCR units will be consumers of the ammonia produced, but, even assuming the OGP supplies ammonia for all of these onsite *consumers*, there will still be a net production of 1,600 lb/hr, which will be transported offsite by truck or rail and sold into the commercial market. If by truck, at periodic intervals, an ammonia tanker truck would arrive onsite, and the stored ammonia would be pumped into the tanker truck and carried offsite to be sold. Approximately six trucks per week of anhydrous ammonia would leave the site. At present, approximately one truck per week brings anhydrous ammonia to the site for use by the existing consumers of ammonia. Transport offsite by rail would be another option to be investigated.

Gas Cleanup Sorbents/Catalysts/Chemicals

Other wastes, listed in Table 1.4-7, will result from the gasification processes. Catalysts (e.g., for the COS hydrolyzer) will be regenerated and reused if possible. Mercury sorbent will likely be disposed of as hazardous waste. Sour water treatment sorbent will be landfilled (pending evaluation of hazard characteristics). Sulfur removal chemicals will be characterized for waste treatment requirements.

__Combined-Cycle Island__

During operation of the related combined-cycle unit, nonhazardous solid wastes will be generated periodically. Wastes generated by the plant will include water treatment system solids, used air inlet filters, waste oils, and other maintenance wastes, along with plant refuse. These wastes will be disposed of at an offsite, licensed landfill.

The facility will also produce maintenance and other wastes typical of power generation operations. Used oils collected from the oil/water separator, spent lubricating oils, and used oil filters from the CT will be transported offsite by an outside contractor and recycled or disposed. Other maintenance-related wastes will include rags, broken and rusted metal and machine parts, defective or broken electrical materials, empty containers, and other miscellaneous solid wastes. These wastes and the typical refuse generated by plant personnel will also be disposed of in an offsite, licensed landfill.

Minimal quantities of hazardous wastes will only be occasionally produced at the plant. All attempts will be made to select and use solvents, paints, and other maintenance chemicals to produce nonhazardous wastes. In the circumstance where hazardous wastes are generated by the plant, the wastes will be managed in accordance with applicable federal and state requirements.

Chemical cleaning wastes will also be generated periodically when the combined-cycle unit's HRSG is cleaned. These wastes were described previously in Section 1.4.2.4.

Table 1.4-7. Expected Operating Characteristics—Materials Requiring Periodic Replacement

	Description	Quantity/Replacement Requirements
Mercury sorbent	Sulfur-impregnated activated carbon used in mercury adsorption columns (two columns estimated for adequate mercury removal)	3,400 ft^3 once per 12 to 18 months per column*
COS hydrolyzer catalyst	Alumina-based catalyst used to convert COS to H_2S for H_2S enrichment/sulfur removal/SO_x reduction	2,000 ft^3 once per 3 years
Sour water sorbent	Activated carbon used for sour water treatment	3,400 ft^3 once per month*
Sulfur removal chemical	Further engineering is required to identify chemicals and amounts required	Unknown

Note: COS = carbonyl sulfide.
H_2S = hydrogen sulfide.
SO_x = sulfur oxides.
ft = foot.
ft^3 = cubic foot.

*Preliminary estimates of volume.

Source: SCS, 2005.

1.4.4.4 Construction and Operational Noise

Construction Noise Sources

The construction of any industrial facility can be divided into five distinct phases for purposes of assessing potential noise impacts:

- Site preparation, including grading and excavation.
- Concrete pouring.
- Steel erection.
- Machinery installation.
- Site cleanup and plant startup.

During the initial site preparation and reclamation and foundation excavation phase for both the OGP and the related combined-cycle unit, heavy diesel-powered earth moving equipment is the major source of noise. This equipment includes bulldozers, graders, sheepsfoot roller compactors, dump trucks, backhoes, and front-end loaders. Typical noise levels such equipment produces can approach 100 A-weighted decibels (dBA) at 50 ft (U.S. Environmental Protection Agency [EPA], 1971). For example, a front-end loader produces 79 dBA and a dump truck produces 91 dBA at 50 ft (EPA, 1971).

Equipment used during the concrete pouring stage includes concrete trucks, cranes, and some earth-moving equipment for backfilling foundations. A pile driver (101 dBA at 50 ft; EPA, 1971) will also be used on the site. The steel erection phase requires the use of cranes in varying sizes, air compressors, welders, material delivery trucks, concrete trucks, and front-end loaders. The machinery installation phase requires the same types of equipment as the steel erection phase.

The final phase, consisting generally of site cleanup and plant startup activities, is typically 10 dBA quieter than the other phases (Barnes *et al.*, 1977), except during the one period of time when the steam lines in the HRSG are being cleaned. Steam is blown through the lines to remove scale or welding debris before being allowed to pass through the turbines, where such materials could damage the blades. The steam is vented to the atmosphere through a temporary bypass line and specially designed baffles constructed specifically for that purpose. Cleaning of the steam lines for the HRSG and steam turbine will require five blows of approximately 18 to 24 hours each over a period of 6 days. The one-time cleaning of the steam lines associated with the OGP gasification island will be 4 to 5 months later and will also require four blows of approximately 18 to 24 hours each over a period of 5 days. For all of these steam blows, a peak sound pressure level at 50 ft of approximately 102 dBA will be produced.

Noise related to truck traffic could be significant during construction due to noise levels generated (91 dBA at 50 ft [EPA, 1971]) and frequency. However, such impacts will be temporary since it would be limited to the construction phase.

Operational Noise Sources

During operation of the OGP and the combined-cycle unit, the primary sources of noise will include railroad delivery, coal handling and crushing equipment, ventilating and circulating air fans, gas turbines, gas and air compressors, boiler feed pumps, gas flow control valves, and the cooling tower. Table 1.4-8 provides preliminary estimates of noise characteristics for key equipment. Section 3.1.6 provides an assessment of potential impacts of this equipment. Specific noise level data will be obtained from the selected manufacturers as design of the facility progresses, and updates of the noise impact assessment will be conducted, if needed. The need for noise control on any specific piece of equipment will be determined by the design engineer such that the total plant noise level will achieve the proposed design objective of a day-night noise level (L_{dn}) consistent with the applicable requirements of the Orange County Code (Article V of Chapter 15) due to plant noise alone. Also, the operations will comply with applicable Occupational Safety and Health Administration (OSHA) requirements for worker noise protection.

1.4.5 HAZARDS ASSOCIATED WITH PROCESS STREAMS, FEEDSTOCKS, AND WASTES

Manageable hazards are presented by the proposed project. This determination is based on a definition of *hazard* as those aspects of the project operation that could result in immediate harm to the public. The specific hazards potentially associated with OGP construction and operation, how those hazards will be managed, and the programs that will

Table 1.4-8. Noise Characteristics of Key Equipment

In process.

mitigate those hazards, both within the plant and with regard to the public, are discussed in Section 3.1.7. Longer-term impacts to air quality, water quality, and waste disposal are not considered to be hazardous and are discussed in other portions of this report.

1.5 RELATED ACTION

As discussed previously, the construction of the combined-cycle island is a related action and is not itself a part of the action that is the subject of this EIV, namely DOE's decision to fund the proposed gasification demonstration project. That is, although integration of the gasifier with the planned combined-cycle island is part of the OGP, the viability of the combined-cycle unit on its own is independent of DOE funding; it will be built whether or not the gasification project goes forward. Thus, for NEPA purposes, the construction of the combined-cycle facilities is considered a related action.

1.6 ALTERNATIVES

This section describes all the reasonable alternatives to the proposed action that were considered, including those that were eliminated from detailed consideration. Only the no-action alternative was considered in detail, and comparison of environmental impacts is provided in the following subsections.

1.6.1 TECHNOLOGY SELECTION

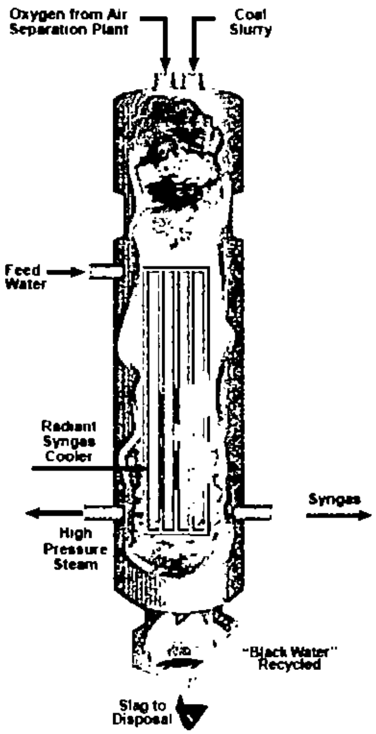
As stated in Section 1.2.2, the primary objective of the OGP is to design, construct, and operate a Transport Gasifier that uses Unites States coal to generate syngas fuel for a commercial-scale, IGCC power plant. Although other gasifier technologies exist (e.g., oxygen-blown systems), and other coal-based fueling options exist (e.g., fluidized bed combustion), only the technology selected can meet the purpose and need for the action (i.e., demonstrating the commercial application of the technology itself). Accordingly, no other technologies were given detailed consideration or evaluation.

1.6.2 SITE SELECTION

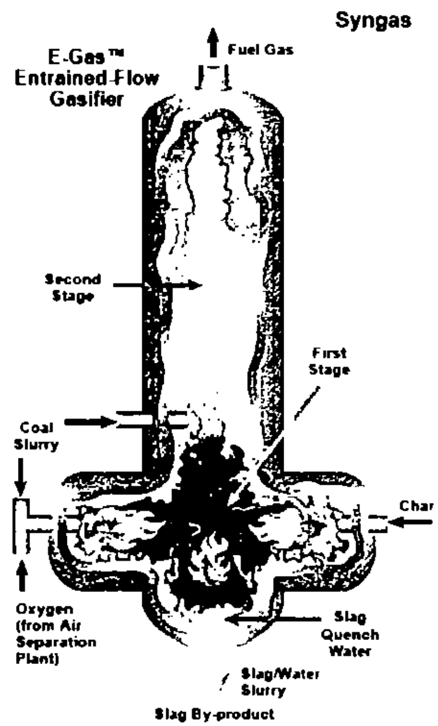
The Stanton Energy Center site was the only site given detailed consideration or evaluation for this project. As a certified power plant site, with existing infrastructure, including coal delivery infrastructure, and because the private partners already enjoyed a business

Visual Comparison of Main Gasifier Types

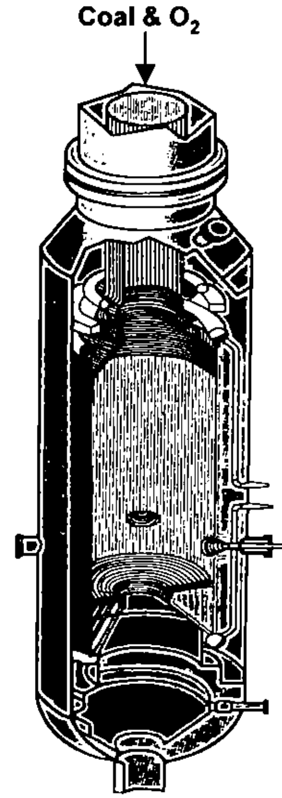
(Not to Scale)



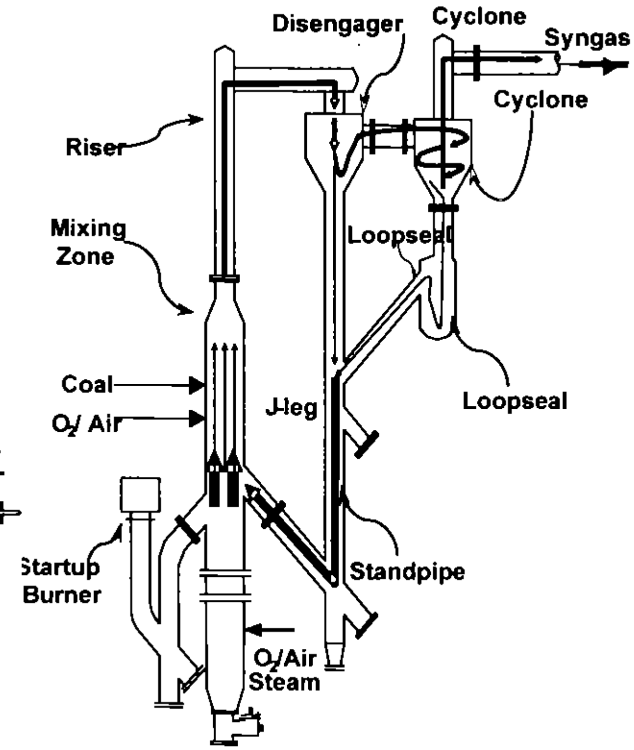
GE Gasifier



Conoco-Phillips Gasifier



Shell Gasifier



Transport Gasifier

OUC The *Reliable* One®

SOUTHERN COMPANY *Energy to Serve Your World®*

Quick Comparison: GE and Transport Gasifiers

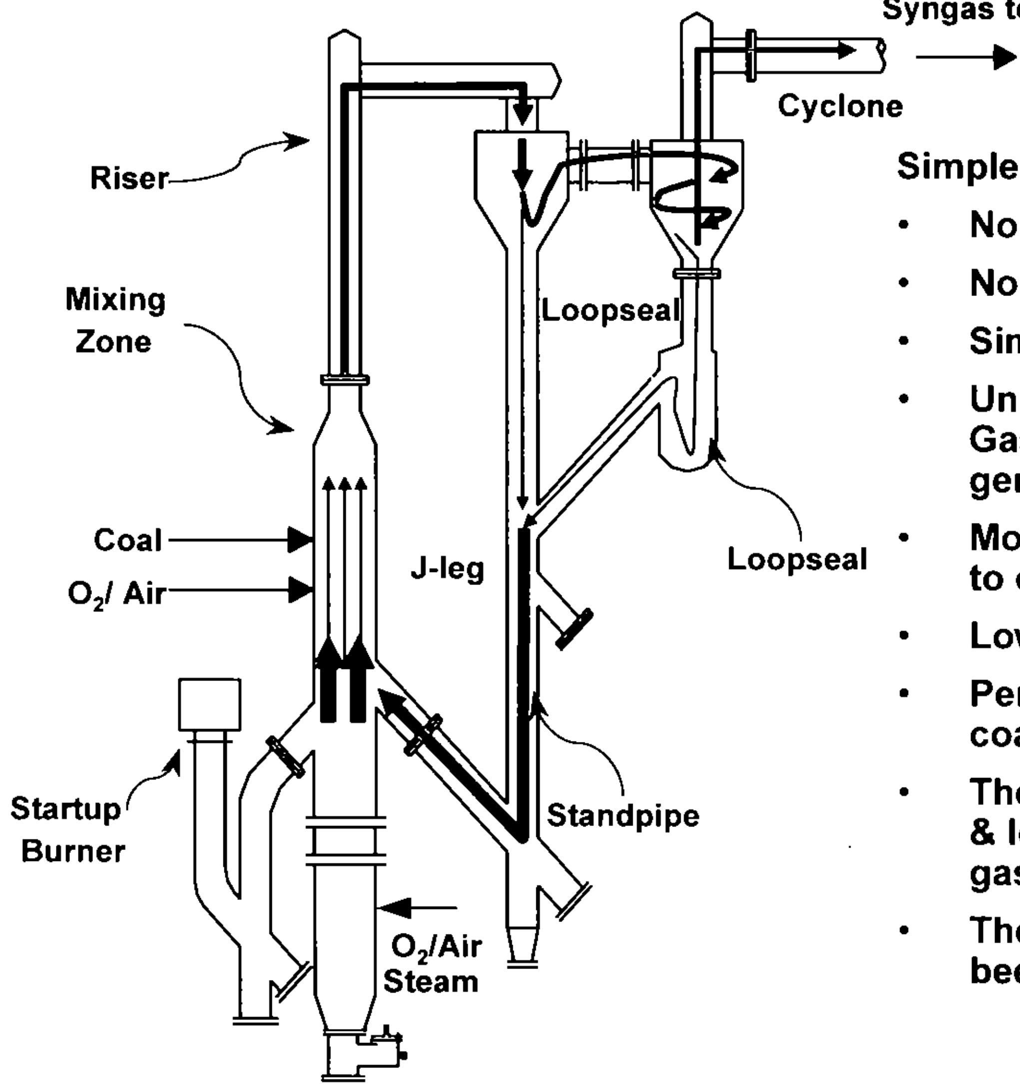
- **There are numerous gasifier types and different embodiments within types:**
  - **Oxygen-blown, air-blown**
  - **Fixed bed, moving-bed, entrained flow, fluid-bed (several types including transport regime)**
  - **Upflow, downflow**
  - **Slagging, non-slagging**
  - **Once through, recycle**
  - **Syngas is quench, radiant, or convective (firetube) cooled**
  - **Dry or slurry fed**
  - **Burner, no burner**

GE gasifier
Transport gasifier

OUC The *Reliable* One®

SOUTHERN COMPANY
Energy to Serve Your World®

Transport Gasifier



Simple Design:

- No burners
- No expansion joints
- Simple and limited internal parts
- Unlike other gasifiers, the Transport Gasifier was developed for power generation
- More efficient and lower cost due to ability to operate Air-blown for power generation
- Low operating temperature
- Performs well on high ash/high moisture coals
- These differences lead to higher reliability & lower O&M cost compared to other gasifiers
- The Transport Reactor at the PSDF has been operated for 15,900 hours.

OUC The Reliable One®

SOUTHERN COMPANY
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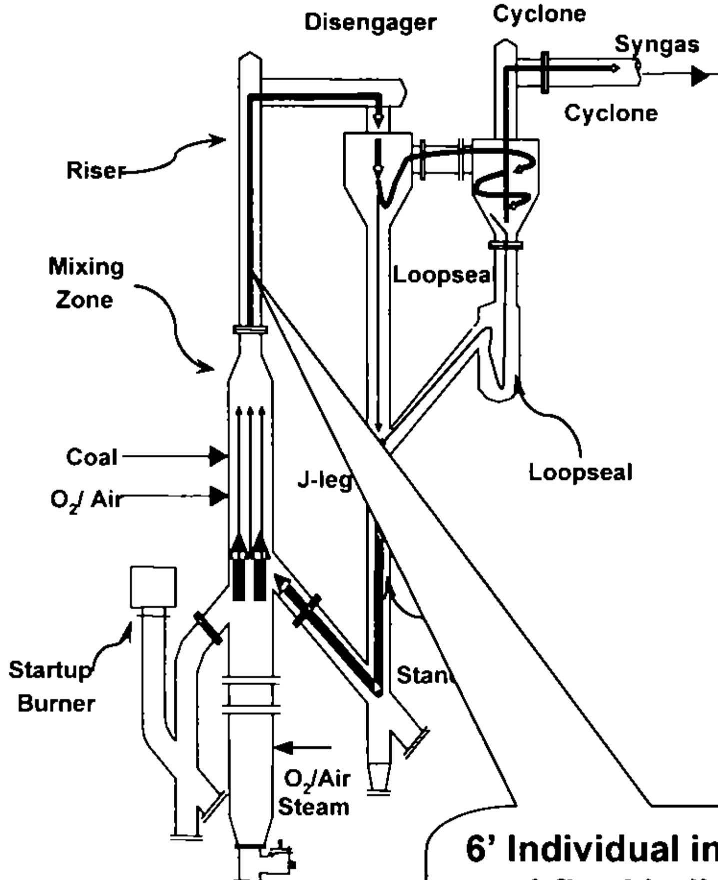
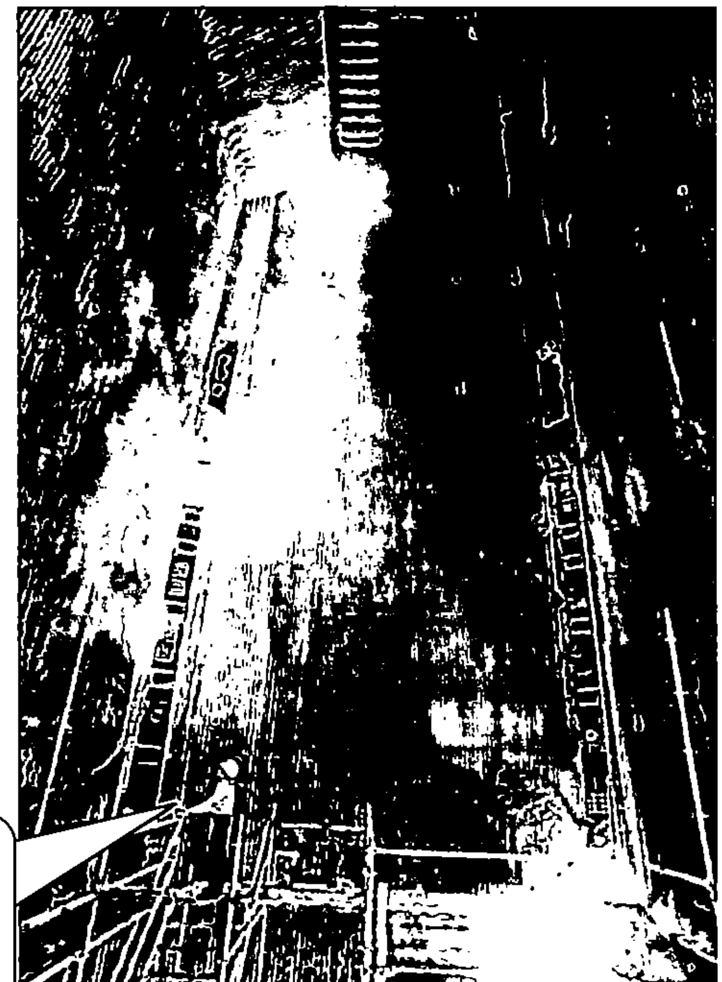
Transport Gasifier



180 MW Tangential-Fired Boiler



6' Individual in a 180 MW coal-fired boiler. Riser in a single 300 MW transport gasifier will be 5–6 feet in diameter

Why A Transport Gasifier?

Text From A Letter From Former EPRI President Kurt Yeager

The technology…has evolved through testing at the Power Systems Development Facility **(PSDF), one of the most successful pilot plant test programs that EPRI has witnessed.**

Work at the PSDF has confirmed that **the Transport Gasifier is unique in that it can be successfully operated in either air-blown or oxygen-blown mode. Hence, the Transport Gasifier is well positioned to make a significant contribution to the reduction of greenhouse gas emissions** from power plants should CO_2 capture be required in the future.

…**the Transport Gasifier readily handled low-rank fuels (e.g. sub-bituminous coal and lignite)**, an important attribute as half the U.S. coal supply, as well as that of half the world's, fits this description. This ability offers important economic and thermal advantages, especially as recent **EPRI studies show that these low-rank fuels are not well-suited for use with oxygen-blown entrained flow gasifiers.**

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Why a Transport Gasifier? (con't)

At the October 2001 Gasification Conference Neville Holt, EPRI Technical Fellow, Advanced Coal Generation wrote:

..."**There is a need to further develop fluidized-bed gasifiers** to enable low-rank and high-ash coals to be added to the feedstocks for IGCC applications. China and India have large resources of domestic coals that they plan to use to fuel their electricity needs. Many of **these coals are of high ash content and are unsuitable for currently commercially developed entrained flow gasifiers. The most promising fluid-bed technology is the KBR Transport Gasifier currently being tested at the PSDF in Wilsonville, AL.** This design is capable of high throughputs and should, if successfully developed, lead to economically attractive IGCC plants."

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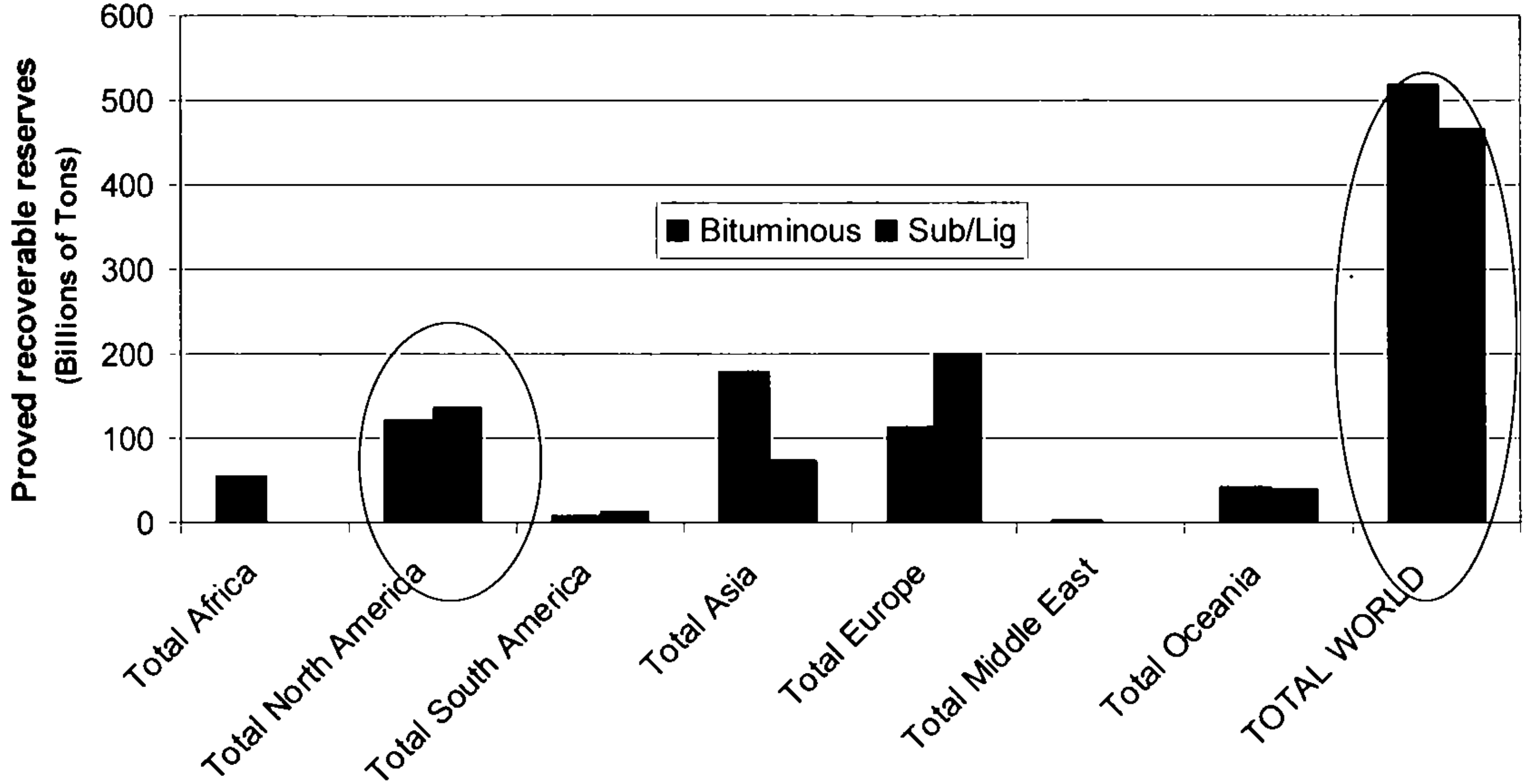
Proven Recoverable World Coal Reserves



Most of the Asian bituminous coal is high in ash. The transport gasifier is better suited for these coals than slagging gasifiers

Sources. World Energy Council Member Committees, 2000/2001, data reported for previous WEC Surveys of Energy Resources; national and international published sources

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Transport Gasifier Syngas/Natural Gas Comparison

Percentage As Delivered to Turbine	Syngas Air-blown	Syngas O_2-blown	Natural Gas
Hydrogen - H_2	12.1	35.9	-
Carbon Monoxide - CO	23.7	42.2	-
Methane - CH_4	2.2	3.1	94.0
Carbon Dioxide - CO_2	7.0	16.6	1.0
Water - H_2O	1.0	0.9	0.0
Nitrogen - N_2	53.9	1.2	1.6
Other	0.1	0.1	3.4
LHV, Btu/scf	125	253	920
HHV, Btu/scf	135	275	1020

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