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Healy Clean Coal Project A DOE Assessment

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Executive Summary

The U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) Program seeks to offer the energy marketplace more efficient and environmentally benign coal utilization technology options by demonstrating these technologies in industrial settings. This document is a post-project assessment of one of the demonstration projects selected in Round III of the CCT Program, the Healy Clean Coal Project (HCCP).

In April 1991, the Alaska Industrial Development and Export Authority (AIDEA) entered into a cooperative agreement with DOE to demonstrate TRW's Clean Coal Combustion System, an advanced slagging combustor and heat recovery system coupled with high- and low-temperature emissions control processes. Other team members included Golden Valley Electric Association (GVEA), host and operator; Usibelli Coal Mine, Inc., coal supplier; TRW, Inc., Space & Technology Division, combustor technology provider; Stone & Webster Engineering Corporation, engineer; Babcock & Wilcox Company (which acquired the assets of Joy Environmental Technologies, Inc.), supplier of the spray dryer absorber (SDA) technology for sulfur dioxide and particulate emissions control; and Steigers Corporation, provider of environmental and permitting support. Foster Wheeler Energy Corporation supplied the boiler. GVEA provided oversight of the design and provided operators during demonstration testing. The project was sited adjacent to GVEA's Healy Unit No. 1, a 25-megawatts electric (MWe) coal-fired power plant located in Healy, Alaska. Fuel for the project was supplied from the Usibelli Coal Mine, about three miles from the project site. Construction started in May 1995 and was completed in November 1997. Operations were initiated in January 1998 and completed in December 1999. DOE provided \$117,327,000 of the total project cost of \$282,300,000, or 41.6 percent.

This project was chosen for funding under the CCT Program based on its potential to provide an economic and efficient boiler and flue gas cleanup system capable of operating on high-ash coal while meeting strict environmental standards for sulfur dioxides (SO₂), nitrogen oxides (NO_x), and particulate emissions (PM).

The objectives of this project, as stated in the cooperative agreement, were to:

- Demonstrate a power plant incorporating a new TRW entrained combustion system coupled with a specially designed boiler, a spray dryer absorber vessel, a baghouse, and a lime activation system.
- Utilize 300,000 tons/yr of a blend of Alaskan sub-bituminous coal and waste coal with a sulfur content of 0.2 percent and an ash level of 18 percent to generate 50 MW of electric power.
- Demonstrate pollutant emissions levels lower than the New Source Performance Standards (NSPS) of 0.18 lb SO₂/MBtu, 0.5 lb NO_x/MBtu, and 0.03 lb particulates/MBtu.

The HCCP boiler is fitted with two 350 MBtu/hr TRW multistage slagging combustors, symmetrically positioned at opposite sides of the furnace. Each unit consists of a precombustor, a slagging stage, and a slag recovery section. The walls of the combustion chamber use tube-membrane construction, and steam generation in these tubes provides cooling. The plant

includes coal- and limestone-handling facilities, the TRW clean coal combustion-boiler system with a nominal capacity of 50 MWe, a spray dryer absorber, a baghouse, ash handling facilities, and a steam turbine/generator.

The plant reached full load for the first time in March 1998. Early efforts focused on completing system characterization tests, optimizing the precombustor burner configuration, and operating conditions, and evaluating integrated system performance. The most important test was the 90-day commercial operations test, conducted from August 17 through November 15, 1999. Altogether, approximately 8,500 hours of coal-fired operations were accumulated, equivalent to about 1 year of continuous operation. The HCCP fired low-sulfur, high-moisture, low-heating value, sub-bituminous coal.

The 90-day commercial operations test was part of a contractual arrangement relating to the acceptance of the HCCP by GVEA. According to the terms of the power sales agreement (PSA), GVEA would operate the HCCP and purchase its net power from AIDEA once the plant became commercially operable (i.e., passed the 90-day test). The Harris Group, Inc. (HGI) was engaged by AIDEA as an independent engineering company to monitor the test. In addition, Duke Engineering & Services, Inc. (DE&S) was engaged by GVEA to evaluate the test on its behalf. HGI, DE&S, and AIDEA all issued reports on the 90-day test. TRW also commented on the performance of the combustors.

Two requirements were to be met during the 90-day test: (1) the plant had to operate for 90 days, generating 91,800 megawatt hours (MWh) of electricity (85 percent of the plant's nominal rating of 50 MWe), while using coal representative of what would be supplied for the life of the plant; and (2) an independent engineering company had to determine that the major systems performed in accordance with design specification and tolerances, and that there was no known reason why the project would not perform on a sustained basis if operated, maintained, and renewed according to standard utility practices.

A summary of conclusions from the various reports on the 90 day test follows. There is agreement that the plant operated for 90 days and generated more power than required by the test protocol. There is also agreement that the average quality of the coal burned was somewhat better than specified in the test protocol. The coal had a heat of combustion of 7,189 Btu/lb, about 3.3 percent higher than specified, and had a little lower ash content.

However, controversy arose over the significance of this variation in coal properties. HGI stated that the deviation biased the 90-day test and that no conclusion could be reached on the test's validity. AIDEA argued that the spirit of the test protocol was met because the text of the protocol stated that the intent of the test was to demonstrate operation on a 6,960-Btu mix and that the test would be run with a coal with characteristics equivalent to those of long-term Usibelli coal. AIDEA believes that both these requirements were met, contending that the blend of coals burned during the 90-day test was representative of what would be provided over the operating life of the plant. Also, during the 90-day test, there was an extended period in which coal was fired with a heating value of 6,960 Btu/lb or less, although there were periods when higher heating value coal was burned.

The other controversy that arose concerned maintenance during the 90-day test. HGI stated that the test was further biased because of the presence of a large on-hand maintenance crew that significantly reduced downtime and that on-line maintenance of critical equipment was beyond normal practice. In essence, HGI concluded that, although the plant ran successfully for 90 days,

maintenance of critical equipment was beyond normal practice and the test was continued with equipment problems that normally would call for the unit to be shutdown for repairs. However, HGI further stated that, had the unit undergone longer shutdowns, the unit would still have generated enough power to pass the 90-day test. AIDEA feels that staffing was not a part of the test protocol and should not have been part of HGI's test evaluation criteria. DE&S stated that the plant experienced mechanical deficiencies that prevented it from being declared commercial. TRW admitted that there were problems but felt that adjustments to operations should solve these problems and that there does not appear to be a need for any major redesign.

A major potential benefit of this technology is that low-grade coal can be burned efficiently while simultaneously achieving low emissions of SO₂, NO_x, and particulates. The HCCP fully met or surpassed all emission limits required by state and Federal environmental standards at the time it was constructed. Carbon burnout was high, with low carbon content in the slag and fly ash. The low-carbon (less than 1 percent) vitreous slag is environmentally benign and can be sold as a by-product or land filled. Because much of the ash is removed in the slagging combustor prior to hot gases entering the furnace, the fly ash load in the furnace is reduced, resulting in less erosion and fouling of the boiler tubes.

Total capital requirement for a 319-MWe net (345-MWe gross) boiler fitted with TRW slagging combustors and an SDA sulfur removal system, and incorporating the improvements resulting from operation of the HCCP, is estimated to be \$455 million, or \$1,320 per kilowatt (kW) (gross). Since this is somewhat higher than capital costs for a pulverized coal-fired boiler, an incentive, such as low-cost fuel or lower emissions requirements, would be needed to justify installation of this technology. Fixed operating costs for the above boiler at a 90-percent capacity factor are estimated to be \$7.1 million/yr, and variable operating costs are estimated at \$28.4 million/yr, for a total estimated operating cost of \$35.5 million/yr. Estimated power costs are 47.4 mills/kWh on a current dollar basis and 36.5 mills per kilowatt hour (kWh) on a constant dollar basis, at a coal cost of \$14/ton.

From an economic standpoint, costs appear to be somewhat high when compared to those for competing boiler types. Although there will be a significant number of new and retrofit power plants in the next 10 to 20 years, it is not clear what share of this market can be captured by the HCCP technology. However, there will likely be situations where the advantages of the HCCP technology will look attractive, particularly in locations where low-quality fuel is available at a reduced price, and limestone is readily available.

From a technical standpoint, the HCCP can be considered a success because it operated for the required 90 days on coal typical of what is expected from the Usibelli Mine. However, because of the reasons discussed above, the HCCP was deemed to have failed the 90-day commercial operating test, a prerequisite for commercial acceptance of the plant. Because the HCCP did not begin commercial operations following conclusion of the demonstration period, the project cannot be viewed as a commercial success.

I Introduction

The goal of the U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) Program is to provide the energy marketplace with advanced, more efficient, and environmentally responsible coal utilization options by conducting demonstrations of new technologies. These demonstration projects are intended to establish the commercial feasibility of promising advanced coal technologies that have been developed to a level at which they are ready for demonstration testing under commercial conditions.

This document serves as a DOE post-project assessment (PPA) of the Healy Clean Coal Project (HCCP), selected under Round III of the CCT Program, and described in a Report to Congress (U.S. Department of Energy, 1991). The desire to demonstrate an innovative power plant that integrates an advanced slagging combustor, a heat recovery system, and both high- and low-temperature emissions control processes prompted the Alaska Industrial Development and Export Authority (AIDEA) to submit a proposal for this project. In April 1991, AIDEA entered into a cooperative agreement with DOE to conduct this project. Other team members included Golden Valley Electric Association (GVEA), host and operator; Usibelli Coal Mine, Inc., coal supplier; TRW, Inc., Space & Technology Division, combustor technology provider; Stone & Webster Engineering Corp. (S&W), engineer; Babcock & Wilcox Company (which acquired the assets of Joy Environmental Technologies, Inc.), supplier of the spray dryer absorber technology; and Steigers Corporation, provider of environmental and permitting support. Foster Wheeler Energy Corporation supplied the boiler. GVEA provided oversight of the design and provided operators during demonstration testing. The project was sited adjacent to GVEA's Healy Unit No. 1 in Healy, Alaska. The objective of this CCT project was to demonstrate the ability of the TRW Clean Coal Combustion System to operate on a blend of run-of-mine (ROM) coal and waste coal, while meeting strict environmental requirements. DOE provided \$117,327,000 of the total project cost of \$282,300,000, or 41.6 percent.

Construction for the demonstration project was started in May 1995, and completed in November 1997. Operations were initiated in January 1998, and completed in December 1999. The evaluation contained herein is based primarily on information from the AIDEA's Final Report (Alaska Industrial Development and Export Authority, 2001), as well as other references cited.

II Project/Process Description

II.A Need for the Technology Demonstration

The continued strength of the U.S. economy requires a secure, environmentally acceptable supply of electric power. Achieving this objective will require the development and commercialization of novel power production technologies into the marketplace; the HCCP is an example of such a technology. This project represents the first commercial-scale demonstration of the TRW Clean Coal Combustion System, an advanced slagging combustor, which is designed to cleanly and efficiently fire a wide variety of coals (including high-ash and waste coals that would otherwise be discarded) with low sulfur dioxides (SO₂), nitrogen oxides (NO_x), and particulate emissions.

II.B Potential of the Technology

The HCCP was chosen for funding because its successful operation would demonstrate an economic and efficient boiler and flue gas cleanup system that could operate using low quality coal and meet strict environmental standards for SO₂, NO_x, and particulate emissions. NO_x emissions were expected to be in the 0.20 to 0.35 lb/MBtu range with CO levels at less than 200 ppm. Removal of SO₂ was expected to be at least 90 percent with low reagent (limestone) consumption, corresponding to an SO₂ emissions level of 0.043 lb/million Btu. Particulate emissions, especially particles below 10 µm (PM₁₀), were expected to be no more than 0.015 lb/MBtu. Vitreous slag produced from coal combustion was expected to be useable as a by-product, or to be suitable for disposal in a nonhazardous solid waste landfill.

II.C Project Description

The HCCP is located in Healy, Alaska, on a site adjacent to GVEA's Healy Unit No. 1, a 25-megawatt electric (MWe) coal-fired electric generating plant. The plant burns coal from the Usibelli Coal Mine, located about 3 miles from the project site. The HCCP boiler is fitted with two TRW slagging combustors, and has a nominal capacity of 50 MWe. The HCCP facility, shown in Figure 1, includes:

- Coal Handling Facilities
- Limestone Handling Facilities
- TRW Clean Coal Combustion/Boiler System
- Spray Dryer Absorber
- Dust Collection Facilities (Bag Filter)
- Ash Handling Facilities
- Steam Turbine/Generator System

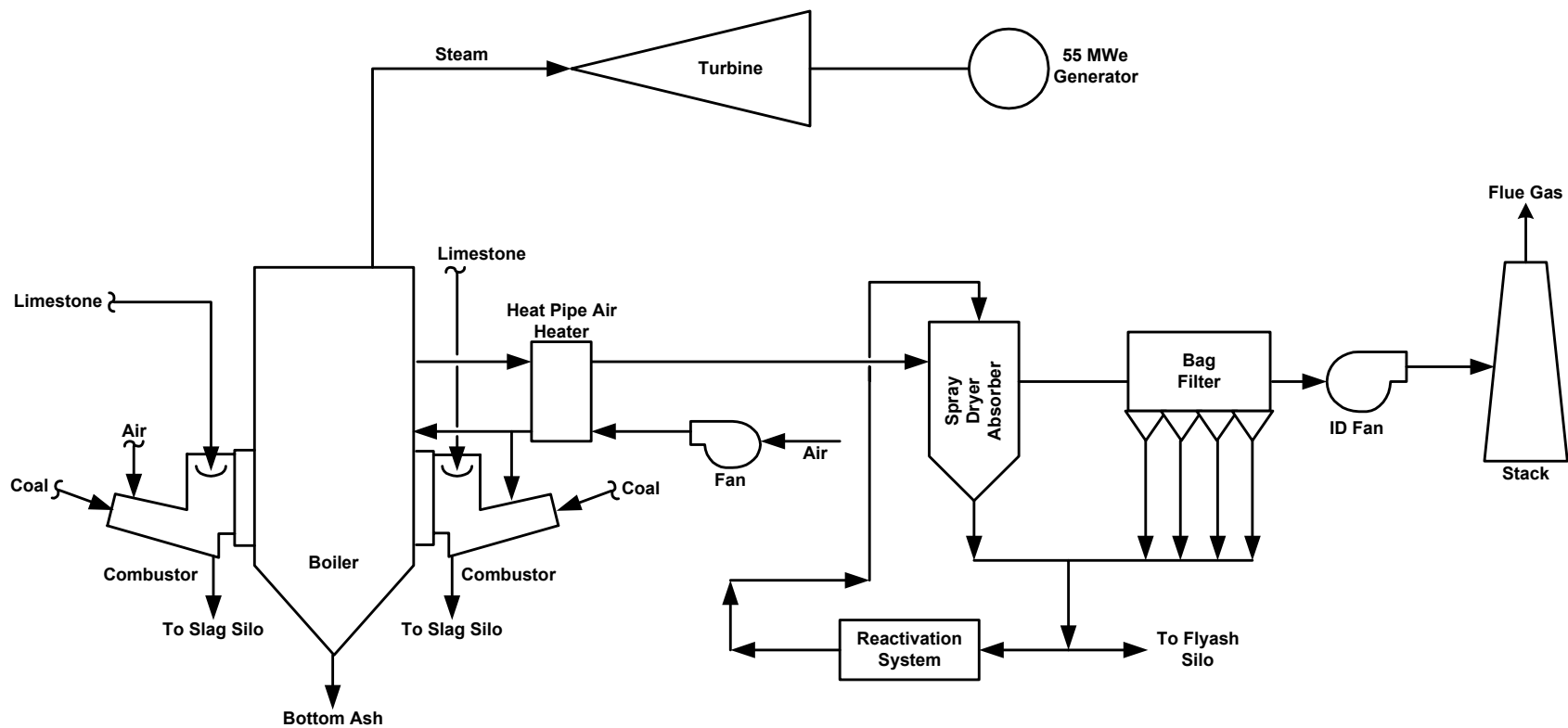


Figure 1. HCCP Facility

II.D Technology Description

II.D.1 Coal Handling Facilities

The purpose of the coal handling and dust collection system is to receive coal from a bulldozer or front-end loader and deliver it to the HCCP coal silos, without excessive dust emissions. Coal is delivered by truck to the storage area, then moved by front-end loader to the inlet hopper of the Stamler feeder/breaker, shown in Figure 2. It passes through the feeder/breaker into one of two coal hoppers. Each coal hopper has its own belt feeder, magnetic separator, and crusher. The crushers discharge onto a conveyor, which transports the coal over a belt scale and through moisture and ash analyzers to the Unit No. 1 coal bunkers. The coal drops off the conveyor and through the coal sampler chute. A series of conveyors then transports the coal to Bunkers 1A and 1B, and to Silos 1A and 1B.

II.D.2 Limestone Handling Facilities

A single limestone feed system (LFS) supplies pulverized limestone to both TRW combustors. Pulverized limestone, nominally 70 percent, minus 200 mesh, is transferred from trucks to the LFS silo via a pneumatic conveying system. Prior to being discharged to the atmosphere, the conveying air passes through a baghouse, which removes entrained particles. The bottom of the silo has a vibrating bin activator to maintain flow. The pulverized limestone is discharged from the silo via a weigh scale feeder and an airlock to a two-way splitter. The flow splitter normally divides the total flow equally between the two combustors, but it can be set to send the entire stream to either combustor. Separate air-driven eductors transport a limestone/air mixture to the limestone injector located near the exit of each slagging combustor.

II.D.3 TRW Clean Coal Combustion/Boiler System

Figure 3 is a schematic showing one of the two 350 MBtu/hr TRW multistage slagging combustors. Each unit consists of a precombustor, a slagging stage, and a slag recovery section. The main chamber of the slagging stage is approximately 9 ft in diameter by 16 ft long. The walls of the combustion chamber are fabricated using tube-membrane construction, and steam generation in these tubes provides cooling. The two combustors are positioned on the furnace as mirror images.

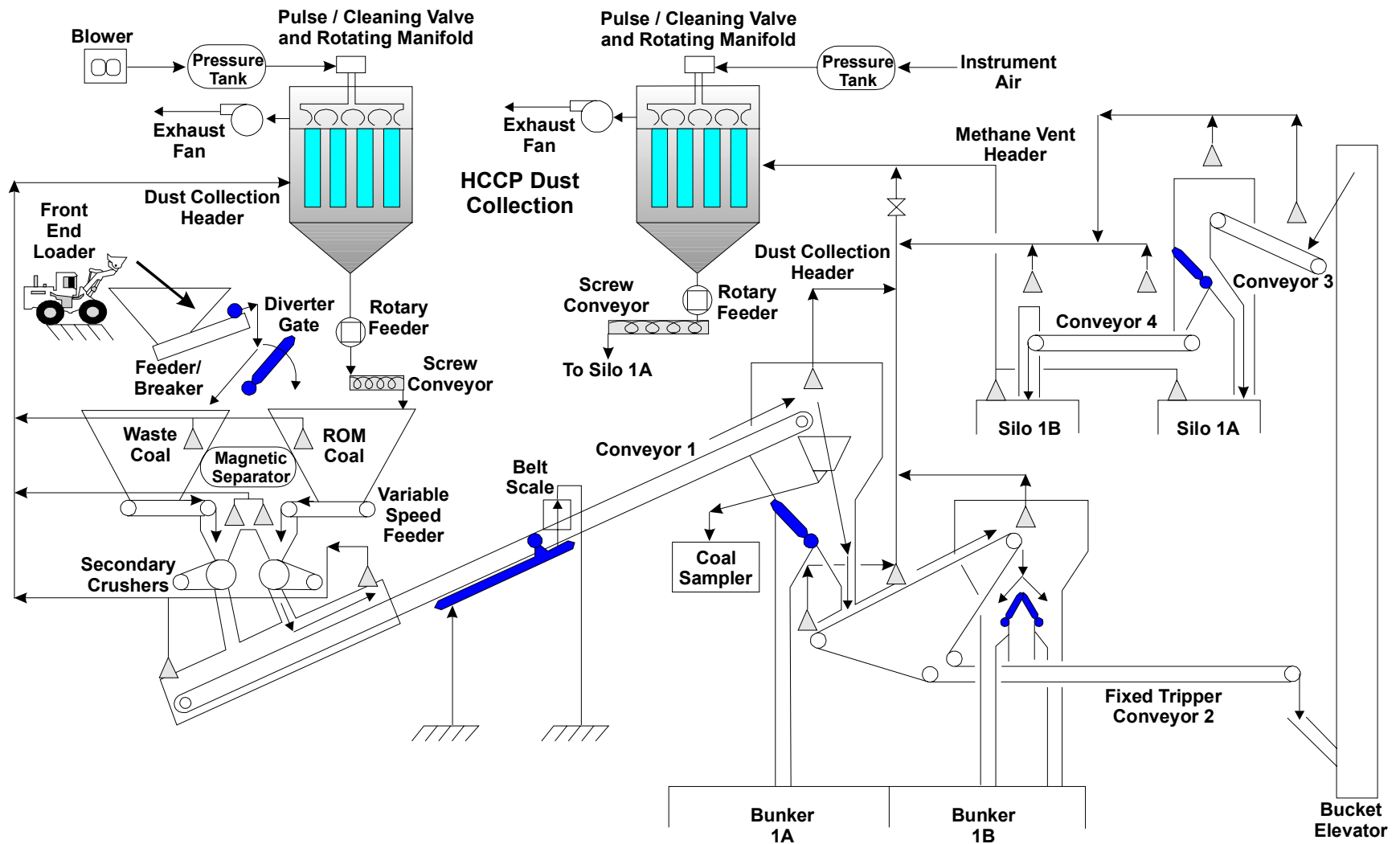


Figure 2. Coal Handling/Dust Collection Facilities

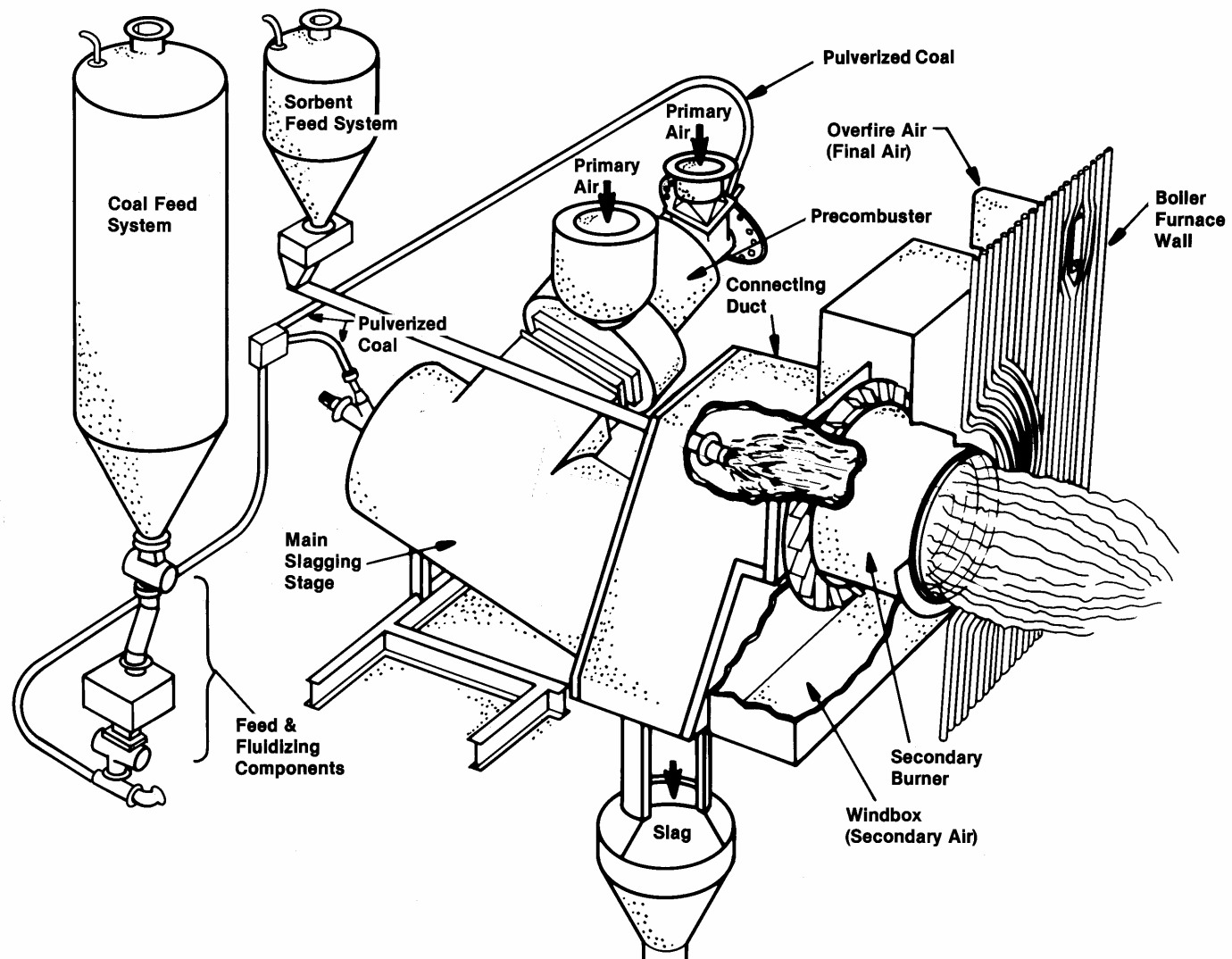


Figure 3. TRW Multistage Slagging Combustor

Pulverized coal is injected into both the precombustor and the slagging stage. The precombustor boosts the combustion air temperature from 500 to 700 °F to 2,300-3,400 °F by burning 30 to 45 percent of the total coal feed. By controlling the temperature and velocity of the oxygen-rich combustion gases entering the slagging stage, the precombustor provides optimum combustion and slag removal. It is designed to ensure stable, efficient combustion of a wide variety of coals, and to prevent slag from freezing within the slagging stage when burning coal with a high ash-fusion temperature under fuel-rich conditions. Low-volatile coal can be accommodated by firing a larger fraction of the coal in the precombustor.

When the furnace was first fired, coal in the primary combustion zone of the precombustor was burned at a stoichiometric ratio of 0.8 to 1.0, followed by a mixing section where secondary air was added, resulting in a stoichiometric ratio of greater than 2.0 at the precombustor exit. This condition caused some problems, so the secondary air was relocated to the head end of the slagging stage to increase the precombustor exit temperature, and to ensure slagging conditions when burning waste coal with a high ash fusion temperature.

The hot combustion gases from the precombustor enter the slagging stage tangentially, thereby producing high-velocity, high-temperature, confined-vortex flow. The balance of the pulverized coal (55 to 70 percent) is introduced through a multiport injector at the head end of the slagging stage. The high temperature produced in the precombustor, along with the strong recirculation patterns, promote a hot slagged surface on the interior of the slagging stage, to ensure stable ignition and combustion. The multiport injector helps distribute the coal evenly for better coal/air mixing and combustion.

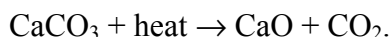
The coal particles burn at a sufficiently high temperature to melt the coal ash. Thus, the precombustor, slagging stage, and the slag recovery section are all operated in a slagging mode (i.e., a molten slag layer coats the inside surfaces). Slag droplets produced by coal combustion are transported to the walls of the combustor by centrifugal action to form a self-replenishing slag layer, which is molten at the surface and frozen at the tubewall interface. The approximately 1 to 1.5-in.-thick frozen layer protects the tubewall from erosion and corrosion and decreases heat losses in the combustor. Gravity and shear forces transport the molten slag along the walls to the slag recovery section. Up to 90 percent of the slag drops into a water bath, where it shatters upon contact, producing a granular, glass-like product. Slag is removed from the slag tank by a drag-chain conveyor.

Because of slag removal in the combustor, only 10 to 25 percent of the coal ash enters the boiler. As a result of the centrifugal action in the slagging stage, the majority of this entrained slag is in the form of small molten droplets less than 10 μm in diameter that solidify at the lower temperature in the boiler. Because these spherical particles have relatively smooth surfaces, they have less tendency to stick together and are less abrasive; thus, they cause less fouling and erosion than typical fly ash particles.

NO_x emissions are reduced through the use of both fuel and air staging. The combustor is operated under carefully controlled, fuel-rich conditions that minimize the formation of NO_x . TRW test data and model calculations indicate that NO_x is minimized by operating the combustor at a stoichiometric ratio of 0.70 to 0.85. As the oxygen-deficient combustion gases exit the combustor and enter the boiler, the addition of the final combustion air is delayed until the gas temperature is reduced by heat transfer to the boiler tubes. This reduces the peak temperature in the furnace and helps to minimize NO_x formation.

Staged combustion also typically results in CO emissions lower than those from conventional low-NO_x burners. In a conventional low-NO_x burner system, both solid fuel combustion and carbon monoxide (CO) oxidation take place within the furnace. Emissions of CO are typically in the 200 to 1,000 ppm range, because of delayed secondary air mixing, and low excess oxygen (2 to 3 percent). Within the TRW combustor, solid fuel combustion is essentially completed before the combustion gases enter the boiler. The boiler is used primarily for CO oxidation (gas-gas reaction) that is mainly dependent on efficient mixing, rather than particle residence time and temperature history within the furnace. During 1998, CO emissions for the HCCP were typically in the range of 10 to 50 ppm (0.01 to 0.05 lb/MBtu).

The slagging combustor/boiler system also functions as a limestone calciner and first stage SO₂ removal system. Pulverized limestone sorbent is injected into the upper region of the slag recovery section, where it is entrained in the flue gas and transported into the furnace. The limestone particles are calcined in the furnace, according to the reaction

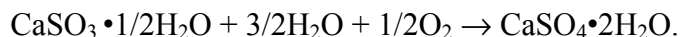
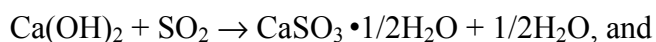
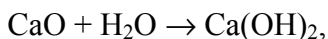


This results in highly reactive flash-calcined lime particles. By the time these particles leave the furnace, they have reacted with some of the SO₂ in the flue gas to form gypsum (CaSO₄). The fraction of SO₂ removed in the furnace depends on the sulfur content of the coal and the Ca/S ratio. For low-sulfur coal (<1 percent sulfur), SO₂ removal in the furnace is typically 15 to 30 percent; for higher sulfur coals (2 to 4 percent sulfur), SO₂ removal can be as high as 50 to 70 percent.

II.D.4 Spray Dryer Absorber

Flue gas, carrying entrained flash-calcined material (FCM, a mixture of flash-calcined lime and fly ash), flows from the air heater outlet through the roof gas-disperser into the spray dryer absorber (SDA), shown in Figure 4. The flue gas mixes with slurry, consisting of a mixture of FCM, reaction products (calcium sulfite and sulfate), and water. A NIRO F-350 rotary atomizer is used to inject the slurry into the incoming flue gas as a fine spray. The roof gas-disperser distributes the incoming gas symmetrically around the rotary atomizer to achieve good mixing of the flue gas with the reagent slurry, thus promoting drying, maximizing SO₂ removal, and minimizing solids deposition inside the SDA.

As the atomized feed slurry mixes with the flue gas, water evaporates and SO₂ removal takes place through a chemical reaction with the hydrated lime in the slurry. Reactions occurring in the SDA are:



As the flue gas and entrained slurry pass through the SDA, the SO₂ concentration is substantially reduced, and spray drying of the slurry is completed. Solids collected in the SDA fall into a hopper at the bottom of the vessel.

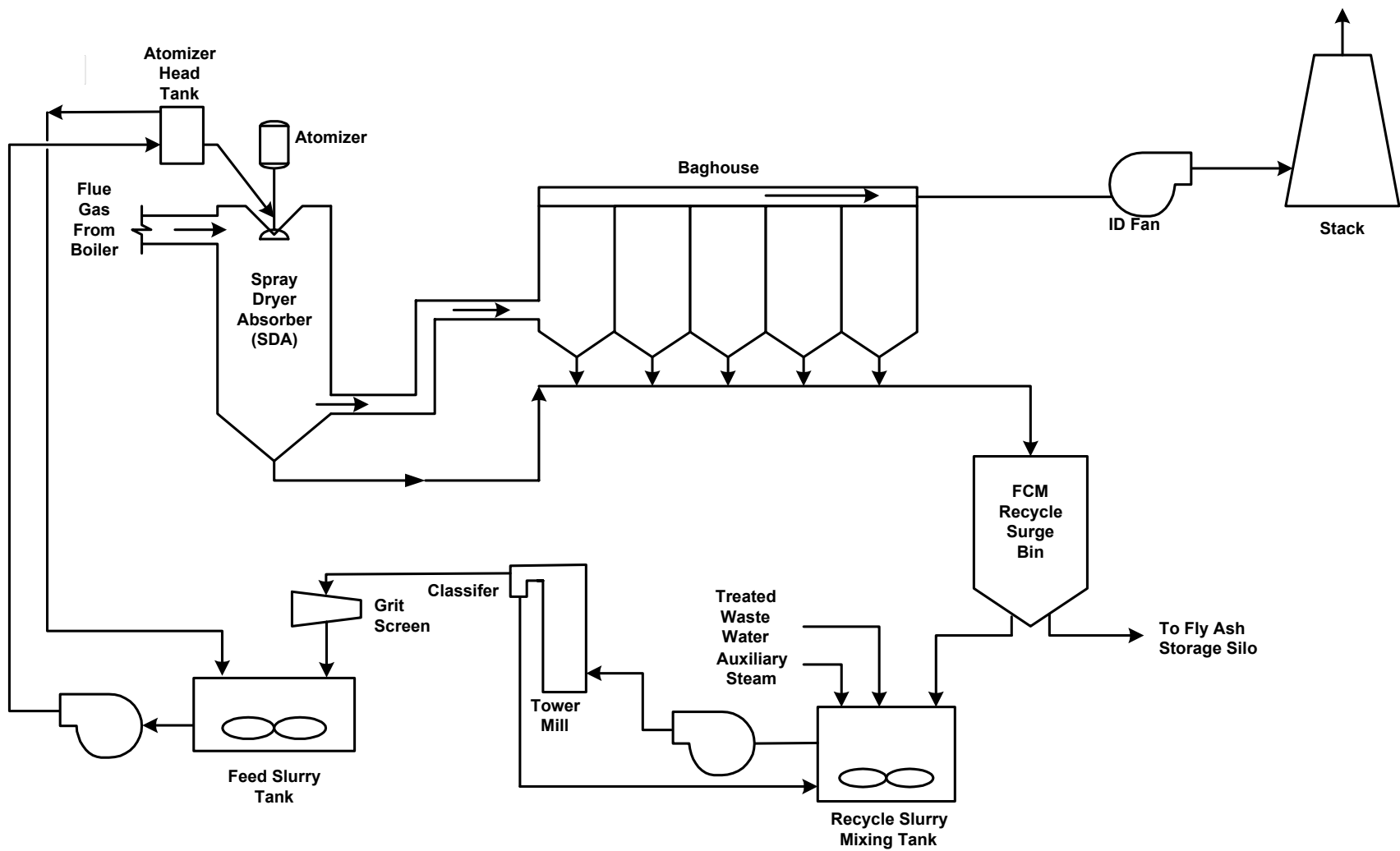


Figure 4. Flue Gas Desulfurization System

II.D.5 Dust Collection Facilities (Bag Filter)

The flue gas and entrained particles of calcium sulfite, calcium sulfate, unreacted lime, and fly ash exit the SDA and flow to the PulseFlo® pulse-jet baghouse, where particulate removal and additional SO₂ absorption occur. The baghouse removes more than 99.9 percent of the particulates from the flue gas before it is discharged to the stack. Depending on the fraction of ash removed in the combustor, the sulfur content of the coal, and the Ca/S ratio, approximately 60 to 90 percent of the solids collected in the SDA and baghouse hoppers is transferred by the ash transport system to the flue gas cleaning system's FCM recycle surge bin. The remaining solids are disposed of as waste. The baghouse consists of ten fabric filter compartments, each of which contains 225, twenty-ft-long by six-in.-diameter fiberglass bags. The gross air-to-cloth ratio is 2.8 actual ft³/min per ft² of bag area.

II.D.6 Ash Handling Facilities

The bottom and slag ash system, shown in Figure 5, consists of two drag chains that receive slag and bottom ash. One drag chain is located underneath the furnace, and the other is located under the combustor slag taps. The drag chains transfer solids along the bottom of the reservoirs, then up the ramp and out of the water onto vibrating screens. Material that is too large for the screen is rejected to a grizzly. These drag chains dewater and discharge the solids to a conveyor that leads to a bucket elevator. The bucket elevator empties onto a belt conveyor that discharges to the bottom ash silo. The bottom ash silo is equipped with vibrators, and stores the ash until it is unloaded into trucks.

To form a seal between the furnace and the atmosphere, the lower half of the drag chains are submerged in water baths. To keep the baths cool, water is circulated from the baths through heat exchangers, then to surge tanks, and back to the baths. In addition to the bottom ash and slag from the HCCP furnace, bottom ash from Healy Unit No. 1, and reject material from the coal pulverizers are also handled by the ash system.

A dry-vacuum fly-ash conveying system, shown in Figure 6, pneumatically conveys collected ash through a pipeline from the existing Healy Unit No. 1 backpass and baghouse hoppers, as well as from the new HCCP boiler bank and air preheated hoppers, to the fly ash silo. A dry pressurized system pneumatically conveys the product from the FCM recycle bin to the fly ash silo. Ash collected from both the vacuum and pressurized systems is conveyed to the common fly ash silo, which is periodically emptied to either tank-type trucks by means of a dry dust unloader, or to open-type trucks by means of a pugmill unloader.

II.D.7 Steam Turbine/Generator System

Steam for the turbine comes from the boiler superheater outlet header at a nominal pressure of 1,250 psig and a temperature of 950 °F. The steam passes through the main stop valve and three governor control valves into the first stage of the turbine. From there it expands through 35 stages of rotating and stationary blades and exhausts into the condenser, which is maintained at a pressure of approximately 1.5 in. of mercury (absolute). A generator is coupled to the end of the turbine shaft to convert the mechanical power input from the turbine into electrical energy, which is sent to the electrical transmission grid. The nominal capacity of the steam turbine/generator system is 50 MWe.

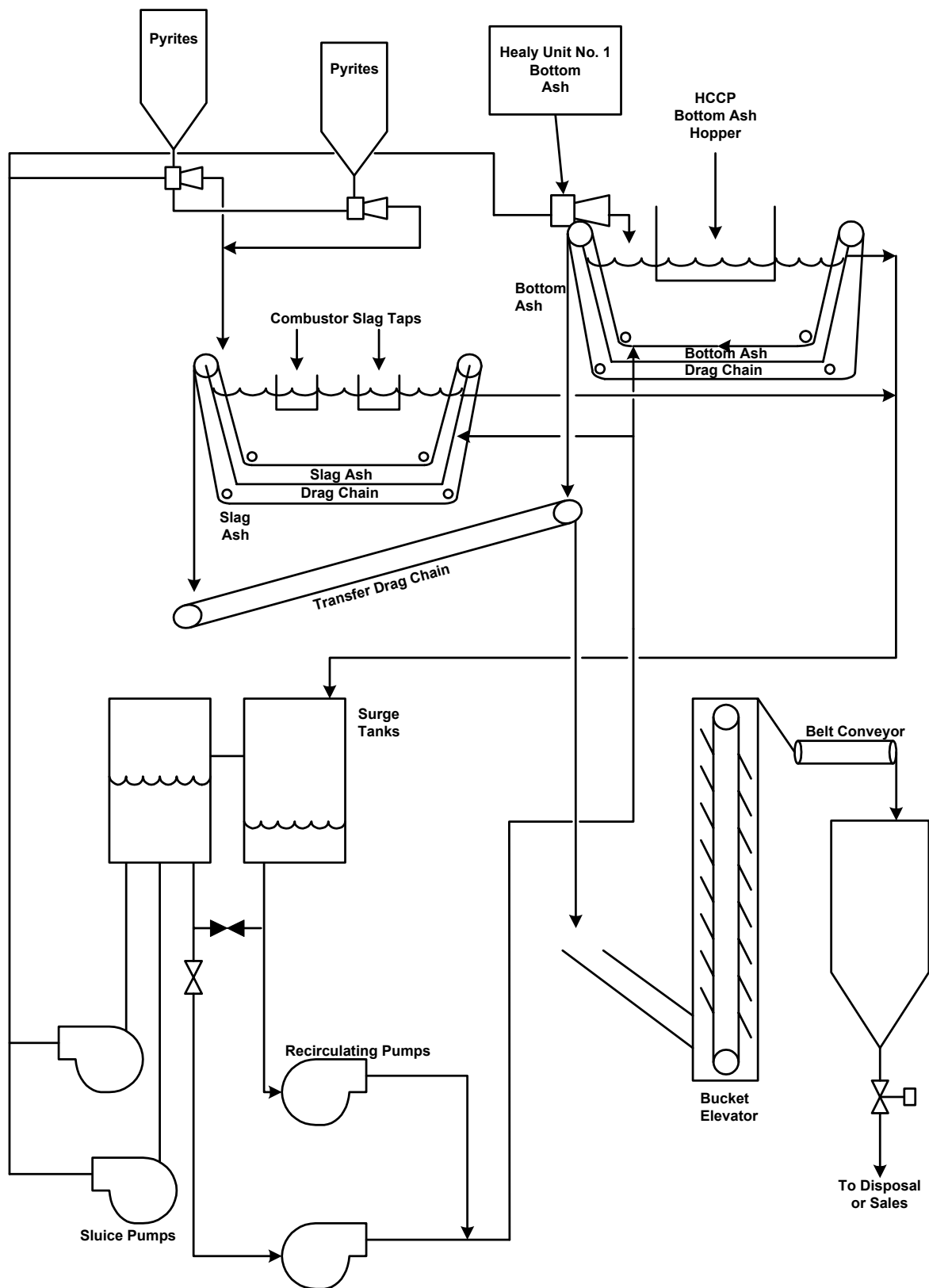


Figure 5. Bottom and Slag Ash System

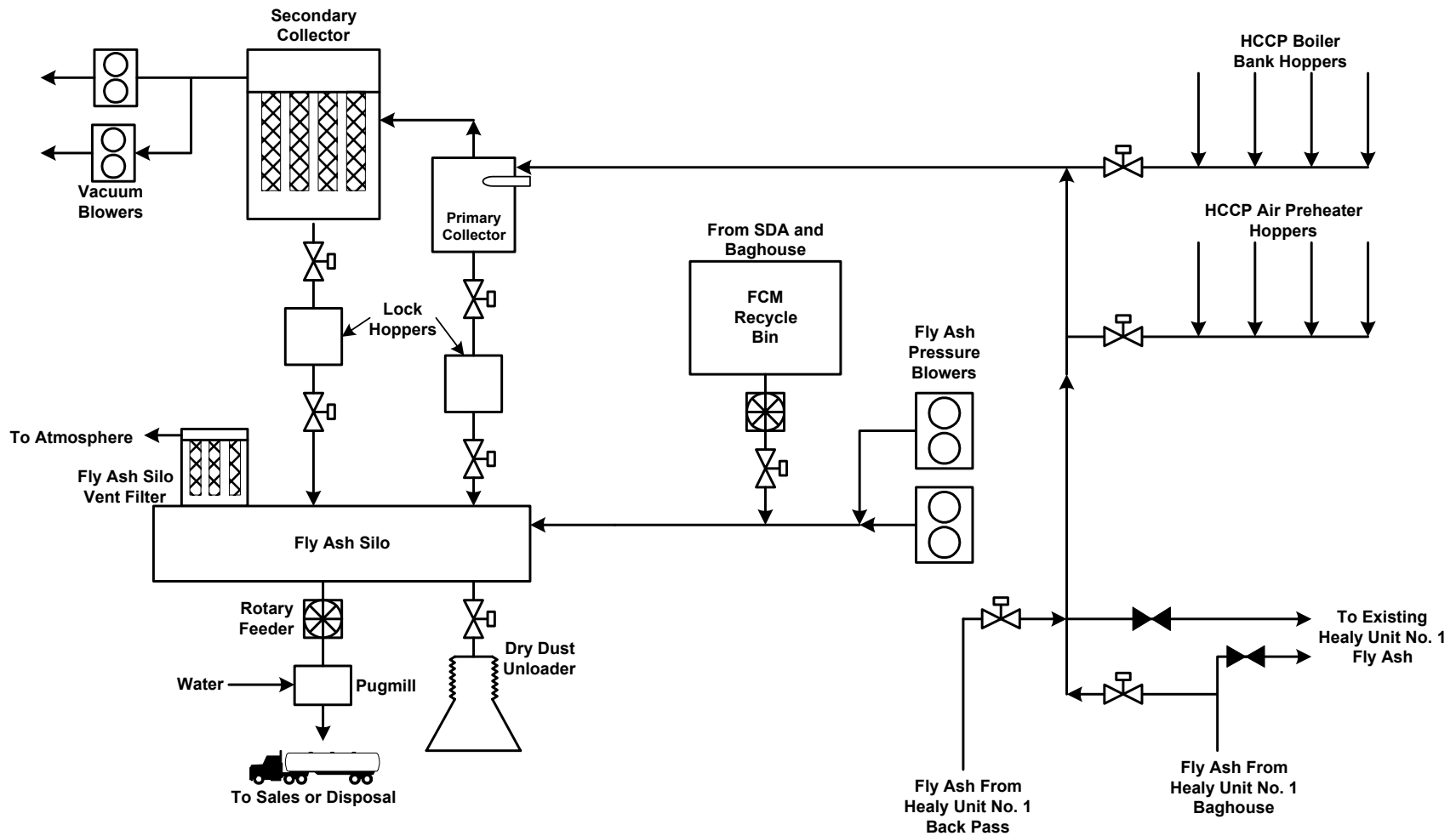


Figure 6. Fly Ash Conveying System

II.E Project Objectives

The objectives of this project, as stated in the cooperative agreement, were to:

- Demonstrate a new power plant design, including a TRW entrained combustion system coupled with a specially designed boiler, that will produce low NO_x levels and function as a limestone calciner, and first stage SO₂ remover in addition to its heat recovery function; a single spray dryer absorber vessel for second stage sulfur removal; a baghouse for third stage sulfur and particulate removal; and a lime activation system, that will recover unused reagent from particulates collected by the baghouse.
- Utilize 300,000 tons/yr of a blend of Alaskan sub-bituminous coal and waste coal with a sulfur content of 0.2 percent and an ash level of 18 percent to generate 50 MW of electric power.
- Demonstrate pollutant emissions levels better than existing New Source Performance Standards (NSPS) of 0.18 lb SO₂/MBtu, 0.5 lb NO_x /MBtu, and 0.03 lb particulates/MBtu.

From these objectives, it is clear that the major goal of this project was to demonstrate the TRW combustor firing low-quality coal, coupled to a cleanup system that would produce excellent pollutant emissions levels.

III Technical and Environmental Assessment

III.A Technical Results

A number of tests designed to compile information on all aspects of the project were performed as part of the HCCP. These tests included coal-firing trials, compliance testing, TRW combustion-system characterization testing, B&W SDA technology characterization testing, boiler characterization testing, coal blend testing, turbine performance guarantee testing, and a 90-day commercial operations test.

The first 4 months were dedicated to coal-firing startup operations, during which all plant systems were methodically brought online while burning run of mine (ROM) coal at partial-load operations. The plant reached full load for the first time in March 1998. From January 1998 through June 1999, approximately 7,200 hrs of plant thermal operations were accumulated. Coal was fired for about 90 percent of this period; the balance of the thermal operations were run using fuel oil, which was also used as the startup fuel. Efforts during 1999 focused on completing the combustion-system characterization test matrix, optimizing the precombustor burner configuration and operating conditions, and evaluating integrated system performance, including SDA characterization testing, during longer duration steady-state tests.

The most important test was the 90-day commercial operations test, conducted from August 17 through November 15, 1999. During this test, an additional 2,000 hrs of coal-fired operations were achieved. Altogether, the system operated feeding coal for about 8,500 hrs, or the equivalent of about 1 year of continuous operations.

III.A.1 Coal

Low-sulfur, high-moisture, low-heating-value sub-bituminous coals from the nearby Usibelli Coal Mine were fired in the HCCP. Table 1 provides typical data from three coals: ROM coal, waste coal, and a ROM coal/waste blend. ROM coal is produced when the mining operation is carried out in a fashion that minimizes the amount of overburden and mineral inclusions in the coal. Waste coal is not subjected to this selective separation process and, hence, has a lower heating value and a higher ash content. (However, when the mine includes fines in the waste coal, its heating value can be higher than that of ROM coal.) The last column in Table 1 gives the properties of a 50-50 blend of ROM and waste coals.

The ROM/waste coal blend is important because it is the coal that was specified by the test protocol to be used in the 90-day commercial operations test. The validity of the 90-day test was questioned because the heating value of the coal burned differed somewhat from that specified in the test protocol. This issue is discussed in more detail in Section III.A.3.

Table 1. Coal Analyses

	ROM Coal	Waste Coal	ROM/Waste Blend
Proximate Analysis (wt %)			
Moisture	26.35	23.87	25.11
Ash	8.20	25.00	16.60
Volatiles	34.56	27.00	30.78
Fixed Carbon	30.89	24.13	27.51
Total	100.00	100.00	100.00
Ultimate Analysis (wt %)			
Moisture	26.35	23.87	25.11
Ash	8.20	25.00	16.60
Carbon	45.55	35.59	40.57
Hydrogen	3.45	2.70	3.07
Nitrogen	0.59	0.46	0.53
Sulfur	0.17	0.13	0.15
Oxygen	15.66	12.23	13.94
Chlorine	0.03	0.02	0.03
Total	100.00	100.00	100.00
Estimated Heating Value (HHV), Btu/lb			
As received	7,815	6,105	6,960
Moisture Free	10,610	8,020	9,295

HHV=higher heating value

The heating value of the coal delivered to the plant depended on a number of factors, such as the seam being mined, the mining technique used, and the specific location within the seam. Thus, its heating value was not constant. Two types of waste coal were used. Conventional waste coal is excavated along the edges of the coal seam and has a heating value typically in the range of 5,000 to 8,000 Btu/lb. Fines waste, ROM coal with a particle size too fine to be sold for conventional boilers, is similar in composition and heating value to ROM coal, but tends to show more variability (typically 6,500 to 9,000 Btu/lb).

The coal properties listed in the cooperative agreement should be considered as only tentative target values. The Usibelli Mine supplied the coal for the project, and HCCP had very little control over its properties. Thus, the average ash content of the coal burned during the 90-day operations test was 12.9 percent, considerably below the target of 18 percent stated in the cooperative agreement.

III.A.2 Limestone

Limestone was supplied locally by Caswell Limestone Company. This limestone averaged about 70-percent calcium carbonate. During the 90-day test, some limestone was supplied from out of

state to meet demand and quality requirements. Typical properties of the limestone used during the 90-day commercial operations test are given in Table 2. The analysis shows that the limestone was nearly pure CaCO_3 , and that it was ground to a very fine mesh size (25 percent smaller than 44 μm). High calcium carbonate content results in lower limestone consumption, and fine mesh size improves its reactivity.

III.A.3 90-Day Commercial Operations Test

The 90-day test was part of a contractual arrangement for acceptance of the HCCP by GVEA. According to the terms of the power sales agreement (PSA), GVEA would operate the HCCP and purchase its net power from AIDEA once the plant became commercially operable (i.e., passed the 90-day test). Thus, the 90-day test had significance beyond demonstrating satisfactory operation. The PSA specified two requirements to be met during the 90-day test:

1. The plant had to operate for 90 days, and during those 90 days, 91,800 MWh of electricity (85 percent of the nominal rating of 50 MWe) had to be generated, using coal representative of what would be supplied for the life of the plant, as specified in the coal purchase contract.
2. The independent engineers, as a result of test observations and inspections, had to determine that the major project systems performed in accordance with design specification and tolerances, and that there was no known reason why the project would not perform on a sustained basis if the plant were operated, maintained, and renewed according to standard utility practices.

The PSA required that the test be monitored by an independent engineering company to ensure that the contractual requirements were met. The Harris Group, Inc. (HGI), engaged by AIDEA, provided this function. HGI prepared an extensive report on the test (Harris Group 1999). In addition, Duke Engineering & Services, Inc. (DE&S) was engaged by GVEA to evaluate the test on its behalf. DE&S also issued an extensive report (Duke Engineering & Services 1999). The participant, AIDEA, issued a report (Alaska Industrial Development and Export Authority 2000a). Finally, TRW provided comments relative to combustor performance (AIDEA 2000a, Appendix A). A number of issues arose as a result of the 90-day test. These are discussed in the following sections.

Table 2. Typical Limestone Properties

Chemical Analysis (wt %)	
Calcium, Ca	39.52
Magnesium, Mg	0.35
Carbonate, CO ₃	59.01
Inert (by difference)	1.12
Total	100.00
Sieve Analysis (wt %)	
Plus 100 mesh	1.13
Minus 100 mesh plus 200 mesh	12.00
Minus 200 mesh plus 325 mesh	62.32
Minus 325 mesh	24.55
Total	100.00

General Performance. Both Harris and DE&S agree that the plant ran for 90 days and generated 102,373 MWh of electricity (more than 10 percent above the minimum required production). The DE&S report states that the 90-day test was conducted in accordance with the test protocol, and the HCCP exceeded the energy production requirement. AIDEA calculated that the plant achieved a slightly less than 95 percent capacity factor during the 90-day test. Thus, the plant met the power generation and time period requirements.

Coal Properties. There is some controversy about whether the coal burned met contractual requirements. This issue arose because, although the PSA did not specify a heating value for the coal burned, the test protocol prepared by HGI specified a heating value of 6,960 Btu/lb. The conclusion of the HGI report was that the coal burned in the 90-day test did not meet test requirements. They argued that the coal was a blend of 61 percent ROM and 39 percent waste coal, rather than a 50-50 mixture as called for in the test protocol. HGI calculated that this resulted in approximately 23 percent less ash handling than would have otherwise been required, and stated that this significantly biased the results so that no definitive conclusion could be reached on the validity of the 90-day test. The DE&S report concluded that the coal burned had an average heating value of 7,189 Btu/lb, which exceeded the test requirement of 6,960 Btu/lb by 229 Btu/lb (3.3 percent).

The AIDEA report argued that the intent of the test, according to the test protocol, was to demonstrate operation on a 6,960 Btu mix, and the test would be run using coal with characteristics equivalent to those of long-term Usibelli coal. It is AIDEA's position that both

these requirements were met. AIDEA argued that the blend of coals burned during the 90-day test was representative of what would be provided over the operating life of the HCCP and, thus, met the spirit of the test protocol. Also, during the 90-day test, there was an extended period in which coal with a heating value of 6,960 Btu/lb or less was fired, although there were periods when higher heating value coal was burned.

TRW contributed that coal is by nature a variable fuel and should be defined by a range of properties rather than by a single value. TRW further stated that it would be difficult to run a 90-day test that exactly matched the average coal heating value expected over the next 30 years. However, over a 15-day period during the 90-day test, the average coal properties were close to the targeted performance coal properties. Since many plant performance tests are only 15 days in duration, this 15-day period could be considered representative of a typical power plant performance test while burning a coal with “average performance coal properties.”

Maintenance Level. HGI stated that “The test was further biased because of the presence of a large on-hand maintenance crew (17 AIDEA contractors, and supervisors), which could and did respond quickly and in force to equipment problems during the 90-day test, thereby significantly reducing downtime. In addition, the online maintenance of critical equipment was beyond normal practice, and the test was continued with equipment problems that normally would call for the unit to be shut down for repair.” In essence, HGI concluded that, although the plant ran successfully for 90 days, maintenance of critical equipment was beyond normal practice, and the test was continued, despite equipment problems that normally would call for the unit to be shut down for repairs. However, HGI further stated that had the unit undergone longer shutdowns, the unit would still have generated enough power to pass the 90-day test. AIDEA argued that staffing was not a part of the test protocol and should not have been part of HGI’s test evaluation criteria. AIDEA also pointed out that staff needed for repairs could be brought in as contract workers, thereby reducing maintenance costs.

Combustor Performance. Despite its conclusion that the 90-day test was biased, HGI had some positive statements to make about the HCCP. HGI expressed the opinion that major plant systems performed in accordance with design specifications and tolerances. HGI also stated that if operated and maintained in accordance with standard utility practice, the plant, as configured, could be considered a commercial plant with efficiency comparable to that of similar plants, provided the coal burned had a heating value above 7,200 Btu/lb. HGI expressed the belief that the lowest heating value at which the unit could run on a sustained basis without serious problems was 6,600 Btu/lb.

TRW agreed with the conclusions from the HGI report, that the TRW coal combustors were acceptable for the original intent and that retrofit of the combustors was not warranted. The major systems performed in accordance with design specifications and tolerances, and there was no reason that the HCCP would not operate on a sustained basis if operated and maintained according to standard utility practices, and the coal remained above 7,200 Btu/lb.

The HGI report noted a difference in slagging behavior between the A and B precombustors, which TRW attributes to damage to the B combustor coal feed system (CFS) dampers that occurred during a fire in the B mill on September 6, 1999. During a system shutdown, an explosion occurred in the inlet primary air duct to coal pulverizer B. The cause appears to have been spontaneous combustion of gases evolved from coal dust because of an abnormally high temperature in the duct. The explosion was caused by errors made during the shutdown, and was

not related to the new technology being demonstrated. Damage was mainly limited to the duct and damper, and the unit was back online in a short time. The shutdown procedure was revised to prevent a recurrence of the problem (Alaska Industrial Development and Export Authority 2001). This fire resulted in maldistribution of coal between the B precombustor and the B slagging combustor. In the A combustor, 34 percent of the coal went to the precombustor at a stoichiometric ratio of 1.4, compared to the B combustor, where 49 percent of the coal went to the precombustor at a stoichiometry of 0.95. TRW concluded that the A precombustor showed satisfactory slagging and that combustor B would also have performed satisfactorily, had not equipment damage prevented proper control of the coal split.

DE&S concluded that, based on the 90-day test and equipment inspections following this test, several serious deficiencies needed to be resolved before the HCCP could operate reliably for extended periods as a cost-competitive power plant.

With respect to the DE&S report, TRW concluded that the comments on the combustion system's performance reflected a basic misunderstanding of the current HCCP multi-stage slagging combustion system design and operation, and that this misunderstanding led to a misinterpretation of the test results. DE&S identified deficiencies in three areas: (1) slag buildup inside the precombustor and transition section, (2) sensitivity of the present combustor configuration to high silica levels in the coal, and (3) inaccessibility of aspirated slag tap viewports to the operators.

With respect to slag buildup, the DE&S report concluded that slag buildup inside the precombustor causes plugs that result in an insufficient air/fuel mix in the main combustor. TRW stated that at no time was there insufficient airflow to the main combustor. Post-test inspection revealed a thin, uniform slag coating throughout the main combustor, independent of precombustor operating conditions. This thin, uniform slag coverage is indicative of high gas temperatures and good combustion in the main combustor.

Concerning sensitivity to silica, TRW argued that assumption by DE&S that the ability to raise the flame temperature in the precombustor is limited because of the slagging that occurs. TRW stated that this is not an accurate assessment of the current design configuration. Design modifications implemented in December 1998 changed the precombustor to a single-stage device operating at a stoichiometric ratio of 1.1 to 1.4, with a gas temperature entering the slagging combustor of 3,000 to 3,300 °F. This gas temperature is considerably higher than the original design, and ensures satisfactory performance with coals having a high fusion temperature ash, such as high silica-content coals. In summary, TRW concluded that the combustor can successfully burn waste coal with a high silica content. The periodic formation of clinkers is not detrimental to combustor performance, and is typically related to changing and/or off-nominal operating conditions. If required, a clinker grinder could be installed.

Relative to the slag tap viewports, DE&S was concerned that inaccessibility would lead to problems controlling slag formation inside the combustors. TRW's main concern was to prevent slag tap plugging by monitoring slag tap conditions. However, during all the 1998 and 1999 test activities and over a wide range of operating conditions, there were no incidents of complete or partial slag tap plugging. TRW concluded that slag tap flow monitoring is not critical; it is adequate to monitor slag quality on the drag chain rather than within the tap.

DE&S concluded that the precombustor was not operating as designed, because it was designed to operate in a non-slugging mode. TRW agreed that the original intent was to operate in a

non-slugging mode, but in mid-1998, the decision was made to operate the precombustor in slugging mode to accommodate a wide range of ash fusion temperatures.

DE&S concluded that the swirl dampers could not be adjusted because of molten slag formation and that this resulted in very poor combustion in the main combustor, and too much combustion in the lower furnace. TRW commented that the intent of the swirl dampers was to allow variation and optimization of the slagging stage inlet velocity and that it is not necessary to adjust the dampers during operation. TRW concluded that at no time did the inability to adjust the dampers affect combustion within the main combustor.

TRW concluded that the combustors performed well, except for some problems with the B combustor, which they attributed to damaged parts as a result of the B mill fire. Minor adjustments to operations should solve these problems, and there does not appear to be a need for any major redesign.

DE&S calculated that the average heat rate during the 90-day test was 12,854 Btu/kWh (26.6 percent efficiency), compared to S&W's initial design phase predicted value of 12,215 Btu/kWh (28.0 percent efficiency). This would somewhat increase plant operating costs and reduce competitiveness.

Coal Feed System. HGI indicated that the CFS would probably require higher maintenance than normal, and because of the expectation of above normal problems with the CFS, the plant might have a lower capacity factor. However, TRW argued that, based on post-test observations, none of the components downstream of the exhauster fan showed a significant wear rate when burning coal with a heating value of 7,200 Btu/lb. Although additional operating time on lower heating value coals is needed, the improved erosion-resistant tiles that were installed should result in acceptable wear rates. Simple changes, such as reducing carrier air flow rate and incorporating improved erosion-resistant tiles in high wear areas should result in further improvements. If the exhaust fan wear rate can be reduced, or an alternative approach for supplying the requisite pressure to the CFS splitter subsystem can be developed, the CFS splitter subsystem downstream of the exhaust fan should perform satisfactorily.

DE&S concluded that various components of the CFS—exhauster fans and cyclones in particular—exhibited high wear rates. TRW commented that the exhaust fan was not within their contractual scope. Post-test inspection of the A combustor CFS revealed negligible wear on the abrasion-resistant tiles, indicating that the TRW-supplied CFS components showed satisfactory wear and reliability. In summary, the identified high wear rates, high maintenance, and unsatisfactory reliability, which DE&S attributed to one of the four cyclones, was caused by damage that occurred to the abrasion-resistant tiles, dampers, or both, as a result of the fire in the B mill. TRW concluded that the lack of any discernible wear within the CFS components of the A combustor supports this conclusion and indicates that the abrasion-resistant tiles were functioning as intended.

III.A.4 Environmental Exceedances

DE&S reported that there were some environmental exceedances during the test: 35 hours of SO₂ violations (1.6 percent of the time) and 14 hours of opacity violations (0.6 percent of the time). DE&S observed no NO_x violations, and NO_x emissions averaged 0.30 lb/MBtu, compared to the permit limit of 0.35 lb/MBtu.

The DE&S report further states that (1) the modifications TRW made to improve combustion caused higher NO_x emissions; and (2) since HCCP NO_x emissions are comparable to Healy Unit 1, which utilizes low- NO_x pulverized coal burners, the HCCP's increased operating complexity and cost are difficult to justify. TRW contends that this statement is inaccurate. There was never a combustion problem in the slagging combustor. The decision to remove the staged secondary air from the precombustor mix annulus and route it to the slagging combustor head-end was implemented to avoid slag freezing at the secondary air injection point and to raise the precombustor exit temperature, thus providing a greater temperature margin when burning coal with a high fusion-point ash. TRW stated that before this change, average NO_x emissions were about 0.25 lb/MBtu. After the change, NO_x emissions were about 0.26 lb/MBtu. Furthermore, at comparable NO_x emissions, HCCP shows much lower CO emissions and loss on ignition (LOI) than does Healy Unit No. 1, which has low-NO_x burners.

Limestone Utilization. HGI, DE&S, and AIDEA all mention that limestone utilization was high. Several reasons emerge for this, including failure of the limestone feeder to operate satisfactorily at low feed rates, and deliberate increases in the limestone rate in order to avoid SO₂ exceedances. However, based on an evaluation of plant performance, there is no reason to believe that the plant would not perform satisfactorily at a much lower limestone rate.

Overall Evaluation. AIDEA concluded that, if appropriate improvements were made to the coal feed system, the plant could be considered capable of sustaining operations for 35 years. Their report further states that fuel flexibility and waste minimization benefits were demonstrated by burning 83 percent previously unsaleable waste coal, including fines, over the 90-day test period. The 90-day test ran within permitted limits for emissions, except for short-term exceedances of SO₂ and opacity that occurred during plant startup, shutdown, and equipment repairs. The report also states that relatively minor improvements are needed in the coal feed system to make the plant capable of 35 years of operations. Some alternative solutions are presented.

Although there is disagreement on whether the coal met the PSA requirements, it is clear that the boiler did operate for 90 days on coal typical of that likely to be supplied during the life of the plant. The difference in heating value between the coal actually burned and the specified coal is small and probably would not have significantly affected the results. The slightly higher coal heating value encountered during the test was likely caused by the inclusion of coal fines, with a high heating value. AIDEA concluded that there is no reason, based on the 90-day test, to believe that the plant would not perform satisfactorily on coal with a heating value of 6,960 Btu/lb. Also, the NO_x level during the 90-day test was reported by AIDEA to average 0.275 lb/MBtu, somewhat lower than the 0.30 lb/million Btu stated by DE&S.

It seems fair to observe that the 90-day test demonstration indicated that the plant could run for an extended period of time, although perhaps with higher-than-normal staff and maintenance, and there is general agreement that some plant improvements and repairs are needed. Given these repairs and improvements, AIDEA believes that maintenance and staffing requirements would be reduced and would approach normal levels. Incorporating lessons learned in this demonstration would allow the design of a new plant to meet prescribed performance criteria.

The HGI report (1999), to some extent, but mainly the DE&S report (1999), identified deficiencies with the combustor design to be corrected before the TRW combustors could be commercially viable. TRW has addressed this issue in their comments and concluded that the

combustors generally performed as desired. It is true that the B combustor did not perform as well as the A combustor, but TRW attributes this to damage that occurred as a result of a fire in the B mill. TRW indicated that, in general, the A combustor performed very well, and its successful operation shows that the concept is viable, particularly since lessons learned from the HCCP would be incorporated into any new implementation of this technology.

III.B Environmental Assessment

The HCCP innovatively integrated an advanced combustor with both high- and low-temperature emissions control processes designed to meet all applicable environmental regulations. It was the first commercial-scale demonstration of TRW's Clean Coal Combustion System coupled with the B&W/Joy/NIRO SDA and baghouse. Plant operation was intended to meet the future energy needs of the region, while reducing emissions levels "well below the requirements of EPA's New Source Performance Standards (NSPS) for new utility coal-fired units" (Alaska Industrial Development and Export Authority, 2001). The project was also configured to achieve compliance with the air, water, and solid waste environmental requirements specified in Alaska's Department of Environmental Conservation Permit programs. It was anticipated that commercial use of the HCCP technology would fulfill future needs for electrical power in Alaska with less environmental impact than conventional coal-based power systems.

The HCCP met or did better than emissions limits required by federal and state environmental standards for air, water, and solid waste discharges in existence for Alaska at the time it was built (construction started in 1995). Further, the project fully met or exceeded the environmental objectives as originally defined. The demonstration test program's environmental goal was to demonstrate that the HCCP could be operated in an environmentally acceptable manner. According to Steigers Corporation, an environmental consulting firm responsible for emissions compliance testing during the project, the HCCP "is a coal-fired power-generating facility that has successfully demonstrated the use of clean coal technology. The 2-year-long demonstration test program provided conclusive data showing that energy needs could be met using coal-fired power plants in an environmentally acceptable manner. The air emission compliance testing program showed that the U.S. Environmental Protection Agency NSPS, the stringent facility air permit emission limits, and the rigorous demonstration test program's emission goals could all be met by the HCCP integrated technologies" (Steigers Corporation 2000).

As shown in Table 3, SO₂ emissions were well below the NSPS, Alaska's air quality permit requirements, and the emissions goals set for the project. NO_x emissions were also within specified limits for plants constructed prior to July 9, 1997. The technology also performed well for control of opacity, PM emissions, and CO emissions. However, some optimization or design modifications would be required when replicating the technology to achieve full compliance with today's more stringent NO_x emissions regulations.

Table 3. Air Emission Limits and Emission Goals for the HCCP

Opacity	PM Emissions	NO_x Emissions	SO₂ Emissions	CO Emissions
Air Quality Permit to Operate No. 9431-AA001 Emission Limits				
20% opacity (3-minute average)	0.020 lb/MBtu (hourly average)	0.350 lb/MBtu (30-day rolling average)	0.086 lb/MBtu (annual average)	0.20 lb/MBtu (hourly average)
27% opacity (one 6-minute period per hour)	13.2 lb/hr (hourly average) 58 tons/yr (full load)	1,010 tons/yr (full load)	0.10 lb/million Btu (3-hour average) 65.8 lb/hr (3-hour average) 248 tons/yr (full load)	202 ppm at 3.0% O ₂ 132 lb/hr 577 tons/yr (full load)
NSPS Emission Limits (40 CFR 60 Subpart Da)				
20% opacity (6-minute average)	0.03 lb/MBtu (hourly average) 99% reduction	0.50 lb/MBtu	70% removal when emissions are less than 0.60 lb/MBtu	Dependent on HCCP ambient CO levels (no requirements listed in 40 CFR 60 Subpart D)
EIS and DTP Emission Goals				
20% opacity (3-minute average)	0.015 lb/MBtu (hourly average)	0.20 lb/MBtu (Final EIS) 0.20 to 0.35 lb/million Btu (DTP)	90% removal 26.1 lb/hr maximum (= 0.043 lb/MBtu at HCCP heat input of 608 million Btu/hr)	200 ppm (dry basis) at 3.5% O ₂ 206 ppm at 3.0% O ₂
Actual Results from the DTP				
2% to 6% (30-minute average)	Not measured (source test March 1999 measured 0.0047 lb/MBtu)	0.208 to 0.278 lb/MBtu, 0.245 lb/MBtu (30-day rolling average)	0.038 lb/MBtu (30-minute average)	30 to 40 ppm (30-minute average)
Actual Results from the 90-Day Commercial Operation Test				
Approximately 5.5% (average)	Not measured	0.275 lb/MBtu (30-day rolling average)	0.060 lb/MBtu (average)	Approximately 20 to 50 ppm

Sources: McCrohan, et al. 2001; Harris Group, 1999

EIS = Environmental Impact Statement

DTP = Demonstration Test Program

The NO_x NSPS for new units were revised in September 1998, during the course of the HCCP demonstration, from an input-based standard of 0.60 lb/MBtu to an output-based regulation of 1.6 lb/MWh of electricity generated. EPA also revised the standard for existing utility boilers that become subject to the NSPS regulation through modification or reconstruction to be equivalent to 0.16 lb/MBtu. To encourage energy efficiency, the NSPS were revised to reflect the performance of the best-demonstrated technology, and converted to an output basis at a heat

rate of 12,500 Btu/kWh (U.S. Environmental Protection Agency 1998). Energy efficient technologies reduce pollution by minimizing the formation of environmental contaminants. EPA based the revised limits for electric utility boilers on the performance achieved by selective catalytic reduction (SCR) units in combination with combustion controls on coal-fired plants. EPA chose SCR as the basis for revising the NO_x emissions limits because of the high NO_x removal efficiency of the technology.

SO₂ and NO_x emissions are major constituents of acid rain and potential contributors to visibility impairment, and NO_x is a primary cause of smog. Smog is a major concern in the northeastern part of the United States, where prevailing weather patterns result in its transport across state boundaries. If the HCCP technology is to be replicated in the lower 48 states, it must meet applicable EPA regulatory requirements, including emissions limitations for SO₂ and NO_x under the Title IV Acid Rain Program, NSPS applicable to plants constructed after July 9, 1997, and the more stringent NO_x State Implementation Plan Call (SIPC) that addresses regional transport of ozone in the northeast.

The HCCP emissions rates for NO_x and SO₂ were well below the Acid Rain Program's regulatory requirements. However, HCCP NO_x emissions, averaging 0.275 lb/MBtu (3.05 lb/MWh at a 12,215 Btu/kWh heat rate), will not meet the revised NSPS criterion for new units without further optimization, and perhaps the addition of technologies such as SCR or Selective Noncatalytic Reduction (SNCR). The advanced combustor technology would also not meet the NO_x emissions requirement in the NO_x SIPC region. To reduce regional transport of ozone, NO_x emissions limits for 2003 under the SIPC are set at 0.15 lb/MBtu for 19 states and the District of Columbia. However, TRW personnel estimate that NO_x emissions levels could be reduced to around 0.10 lb/million Btu by injecting ammonia into the combustor (Alaska Industrial Development and Export Authority 2001).

To reduce maintenance and waste management costs and to meet more stringent particulate control requirements, utilities have, over time, increased their use of coals with a lower ash content. The average ash content of coals burned by U.S. utilities has decreased consistently, from 13.5 percent in 1975, to 9.22 percent in 1996 (U.S. Environmental Protection Agency 1999). Since the coal used in the HCCP project is a blend of ROM and waste coals, the combustion ash content of the resultant mixture tends to be somewhat higher than that typically found in non-waste blends being used today. Additional solid waste is also generated from the use of pulverized limestone sorbent for SO₂ control. Because of the nature of the combustor, however, much of the ash can be recovered as vitreous non-leachable slag, which can be sold as a by-product. The strength of the advanced slagging combustor lies in its ability to utilize even relatively low-quality coals, such as waste coals having a high ash content. Therefore, the technology demonstrated in the HCCP project adds flexibility to the overall suite of processes available to reduce the environmental impact of fossil-fuel combustion.

IV Market Analysis

IV.A Market Size/Commercialization

The HCCP technology consists of the TRW Clean Coal Combustion System, plus the B&W/Joy/NIRO SDA and baghouse. The benefit of this technology is that low-grade coal can be burned efficiently while achieving low SO₂, NO_x, and particulate emissions. Carbon burnout is high, with low carbon contents in the slag and fly ash. The low-carbon (less than 1 percent), vitreous slag is environmentally benign and can be sold as a by-product. The fly ash, containing less than 0.5 percent carbon, can be sold or land filled. Because much of the ash is removed in the slagging combustor prior to hot gases entering the furnace, the fly ash load in the furnace is reduced, resulting in less erosion and fouling of the boiler tubes.

The TRW combustor has been demonstrated, in the HCCP and other tests, to burn coals of widely varying properties. Heating value has varied from 6,650 Btu/lb to 13,000 Btu/lb; ash level from 5 percent to 23 percent; and ash fusion temperature from 2,100 °F to 2,900 °F. The system does require limestone; therefore, limestone must be accessible in the vicinity of the plant. However, limestone is widely available, and the system can even operate with poor quality limestone, so supply should not be a significant problem. TRW combustors are amenable to either bottom firing or side firing. Retrofit applications are generally side-fired.

According to the Energy Information Administration, over 300 gigawatts of new electric power generating capacity will be needed in the United States by 2020 (2000). It is unclear exactly what fraction of this capacity will be coal-fired, but the availability of advanced technology, such as that demonstrated in the HCCP and the tightening of natural gas supplies, should result in coal usage for a significant fraction of the planned capacity increase. The advantages listed above for the HCCP technology should enable it to capture a portion of the new and retrofit coal-fired electric generation plant market. The major competitor of the HCCP technology would appear to be fluidized bed combustion, which is also capable of burning low quality fuels. The impact of the acquisition of TRW by Northrop Grumman on the commercialization of the TRW Clean Coal Combustion System is unclear.

IV.B Economic Analysis

The basis for the economic analysis of a coal-fired boiler fitted with a TRW Clean Coal Combustion System and an SDA sulfur removal system is given in Table 4. An analysis was conducted for a 319-MWe (net) power plant operating at a 90-percent capacity factor (AIDEA, 2001). Compared to a pulverized coal-fired boiler with low-NO_x burners emitting NO_x at a level of 0.4 lb/MBtu, NO_x production is reduced to 0.26 lb/MBtu (35 percent reduction). For a coal sulfur level of 0.37 percent, uncontrolled SO₂ would be 0.91 lb/MBtu; this is reduced to 0.035 lb/MBtu (96 percent removal) with the HCCP technology. The following analysis is based on new plant construction, but there is also opportunity for retrofitting the technology to existing plants at reduced cost. However, because retrofitting situations are very site specific, it is difficult to produce meaningful economic analysis for a general retrofit situation. Therefore, no retrofit analyses are provided.

Table 4. Parameters Used in Economic Evaluations

Parameter	Value
Cost of Debt, %	8.5
Dividend Rate for Preferred Stock, %	7.0
Dividend Rate for Common Stock, %	7.5
Debt, % of Total Capital	50.0
Preferred Stock, % of Total Capital	15.0
Common Stock, % of Total Capital	35.0
Income Tax Rate, %	38.8
Investment Tax Credit, %	0.0
Property Tax & Insurance, %	3.0
Inflation Rate, %	4.0
Discount Rate (with Inflation), %	7.925
Discount Rate (without Inflation), %	3.744
Escalation of Raw Materials Above Inflation, %	0.0
Construction Period, Years	1
Allowance for Funds Used During Construction, %	0.0
Construction Down Time, days	90
Remaining Life of Power Plant, years	15
Year for Costs Presented in this Report	1993
Royalty Allowance, % of Total Capital	0.5
Capital Charge Factor - Current Dollars	0.160
- Constant Dollars	0.124
O&M Levelization Factor - Current Dollars	1.314
- Constant Dollars	1.000
Power Plant Capacity Factor, %	90
Sales Tax Rate, %	5.0
Cost of Freight for Process Equipment, %	2.0
General Facilities, % of Total Process Capital	0.0
Engineering & Home Office, % of Total Process Capital	0.0

IV.B.1 Capital Costs

Estimated capital cost for a 319-MWe net (345-MWe gross) boiler fitted with a TRW Clean Coal Combustion System and an SDA sulfur removal system is given in Table 5. The plant location is Wyoming, chosen because of the availability of low-cost, low-heating value, low-sulfur coal. Total capital requirement for a unit incorporating the improvements resulting from the lessons

learned from operation of the HCCP is estimated to be \$455 million, or \$1320/kW (gross). This is somewhat higher than for a pulverized coal-fired boiler and indicates that there should be an incentive, such as low-cost fuel or lower emissions requirements, to justify installation of this technology.

Table 5. Capital Requirements for 345-MWe (Gross) Plant*

Area	Item	\$ million	\$/kW (gross)
100	Coal Unloading and Handling	6.9	19.9
200	Sorbent Unloading and Handling	3.4	10.0
400	Combustion/Steam Generation	201.3	583.6
700	Power Generation	170.5	494.1
800	Sulfur Dioxide Removal	15.5	44.9
1000	Particulate Removal	11.8	34.2
1400	Ash Collection and Removal	5.2	15.1
1500	Civil/Structural/Architectural	36.0	104.3
A	Total Process Capital	450.6	1306.1
B	General Facilities	Included in A	Included in A
C	Engineering	Included in A	Included in A
D	Project Contingency	0.0	0.0
E	Total Plant Cost (A+B+C+D)	450.6	1306.1
F	Allowance for Funds During Construction	0.0	0.0
G	Total Plant Investment (E+F)	450.6	1306.1
H	Royalty Allowance (0.5% of A)	2.2	6.5
I	Preproduction Costs (3 months)	1.0	2.9
J	Inventory Capital	1.0	2.9
K	Initial Chemicals	0.1	0.0
L	Subtotal Capital (G+H+I+J+K)	454.9	1318.4
M	Cost of Construction Downtime	0.0	0.0
N	Total Capital Requirement (L+M)	454.9	1318.4

* Net plant capacity is 319 MWe.

IV.B.2 Operating Costs

Estimated operating costs are shown in Table 6. For a 319-MWe (net) boiler fitted with TRW slagging combustors and an SDA sulfur removal system and operating at a 90 percent capacity factor, fixed operating costs are \$7.1 million/yr, and variable operating costs are \$28.4 million/yr, for a total operating cost of \$35.5 million/yr.

Table 6. Operating Costs for a 345-MWe (Gross) Plant*

(a)		Quantity	\$/Unit	\$10 ³ /yr
Fixed O&M Costs				
Operating Labor	man hr/hr	9	21.00	1,656
Maintenance Labor				2,100
Maintenance Material				3,200
Administration/Support Labor				200
Subtotal Fixed Costs				7,156
Variable Operating Costs				
Coal	ton/hr	217.1	14.00	23,962
No. 2 Fuel Oil	gal/hr	57.1	2.00	900
Limestone	ton/hr	7.91	20.00	1,247
Acid	lb/hr	1.48	1.07	13
Caustic	lb/hr	2.1	2.14	35
Steam	10 ³ lb/hr	1.2	3.50	33
Condensate	10 ³ lb/hr	2.2	0.77	13
Raw Water	10 ³ gal/hr	203	0.60	960
Electric Power	kW	38.1	0.05	15
Ash Disposal	ton/hr	16.15	9.29	1,183
Subtotal Variable Costs				28,361
Total O&M Costs				35,517

*Net Plant Capacity is 319 Mwe.

IV.B.3 Economics

Estimated levelized cost of power for a 319-MWe (net) boiler fitted with TRW slagging combustors and an SDA sulfur removal system are shown in Table 7. The analysis was conducted for a power plant operating at a 90-percent capacity factor. Costs are levelized both on a current dollar and a constant dollar basis. These economics are based on a plant design using data generated in the 90-day test, and based on a logical extrapolation of the results achieved in the HCCP.

Table 7. Economic Analysis* for a Boiler Using TRW Combustors

Levelized Cost of Power	Base, \$million	Current Dollars		Constant Dollars	
		Factor	mills/kWh	Factor	mills/kWh
Capital Charge	455	0.160	28.9	0.124	22.4
Fixed O&M Cost	7.156	1.314	3.7	1.000	2.8
Variable Operating Cost	28.361	1.314	14.8	1.000	11.3
Total			47.4		36.5
Levelized Cost of SO₂ + NO_x Removal**	Base, \$million	Current Dollars		Constant Dollars	
		Factor	\$/ton rem.	Factor	\$/ton rem.
Capital Charge	455	0.160	5,149	0.124	3,991
Fixed O&M Cost	7.156	1.314	665	1.000	506
Variable Operating Cost	28.361	1.314	2,636	1.000	2,006
Total			8,450		6,503

*Basis: 319 MWe (net); 90% capacity factor; 15-yr life; 1.712 million ton/yr of 0.37% sulfur coal; 12,176 tons of SO₂; and 1,959 tons of NO_x removed per year.

**Costs per-ton-of-pollutant-removed are high because they are based on entire plant cost, not just cost of pollution control equipment.

Levelized busbar power costs are estimated to be 47.4 mills/kWh on a current dollar basis and 36.5 mills/kWh on a constant dollar basis. These costs are consistent with results from DE&S who estimated total plant operating cost during the 90-day test of 57 mills/kWh, based on their economic model. Taking into account the economies of scale and the incorporation of lessons learned from the HCCP, the results in Table 7 are in excellent agreement with DE&S's estimate. On the basis of pollutant reduction, levelized costs are \$8,450/ton of SO₂ plus NO_x removed on a current dollar basis and \$6,500/ton on a constant dollar basis. The design of the HCCP incorporates some aspects of pollution control directly in the combustor; therefore, it is difficult to allocate costs applicable to only pollution control. Thus, the costs calculated for SO₂ and NO_x removal are high because they distribute the entire project cost, not just pollution control equipment costs, over the amount of pollutant removed.

Additional economic analyses were performed to determine the impact of various parameters, such as plant size and coal sulfur level, on economics. The results of these analyses are shown in Tables 8 and 9.

These results show that plant size and coal sulfur content have relatively little effect on the cost of power. Power cost decreases only about 10 percent with a fourfold increase in plant size from 319 MWe to 1,276 MWe. Increasing coal sulfur content from 0.37 percent to 3 percent increases power cost by less than 10 percent.

Capacity factor has a larger effect on power costs, as shown in Table 10. A decrease in capacity factor from 90 percent to 65 percent increases power costs by 27 percent.

Table 8. Effect of Plant Size on Power Cost

Plant Size, MWe (net)	Constant \$	Current \$
319	36.5	47.4
532	35.5	46.1
957	34.2	44.4
1,276	33.0	42.7

Levelized Cost of Power, mills/kWh

Table 9. Effect of Feed Coal Sulfur Content on Power Cost*

Coal Sulfur Content, wt%	Constant \$	Current \$
0.37	36.5	47.4
1.00	37.5	48.8
2.00	38.9	50.6
3.00	40.0	52.0

Plant Size 319 MWe (net)

Levelized Cost of Power, mills/kWh

Table 10. Effect of Capacity Factor on Power Cost*

Capacity Factor, %	Constant \$	Current \$
65	46.3	60.2
75	41.6	54.1
85	38.0	49.5
90	36.5	47.4

**Plant Size 319 MWe (net)*

Levelized Cost of Power, mills/kWh

V Conclusions

As with all new technologies, there were some initial problems with the HCCP, but for the most part these were solved. By completing the 90-day test, the HCCP demonstrated that a boiler fired by the TRW Clean Coal Combustion System and with a B&W/Joy/NIRO SDA and baghouse for flue gas cleanup could, in principle, operate for an extended period of time and produce power at essentially the rated capacity, while burning coal with a relatively high ash and low heating value. Some technical issues have not been fully resolved, but TRW engineers believe that these can be overcome. Thus, the first objective in the statement of work (SOW), demonstrating a new power plant design, can be considered achieved, especially in light of the fact that design improvements would be made in the next unit as a result of lessons learned from HCCP.

Advantages of the TRW combustor are that it can burn low-quality coal and achieve high ash collection in the combustors and boiler. Most of the ash is produced as non-leachable vitreous slag, which can be sold as a by-product or disposed of in a nonhazardous landfill. The HCCP technology produces low CO, low carbon in ash, low SO₂, low particulates, and relatively low NO_x emissions, and it can even operate with low-quality limestone. The third objective of the cooperative agreement was achieved, demonstrating pollutant emissions better than the existing NSPS.

From a technical point of view, the HCCP can be considered a success in that it operated for the required 90 days on coal typical of that expected from the Usibelli Mine. However, because the properties of the coal burned during the 90-day test differed slightly from those specified in the test protocol, the HCCP was not deemed to have passed the 90-day commercial operating test, a prerequisite for commercial acceptance of the plant. Therefore, rather than continuing to operate, the HCCP was shut down, and the overall operation cannot be viewed as a commercial success. As a result, the potential of the HCCP to use 300,000 tons/yr of Alaskan coal, the second objective in the cooperative agreement, was not achieved.

Economically, costs appear to be in the upper range when compared to those for competing boiler types. Although there will be a significant number of new and retrofit power plants in the next 10 to 20 years, the fraction of the potential market that can be captured by the HCCP technology is unclear. However, it seems likely that opportunities for exploiting the advantages of the HCCP technology will exist. In general, this technology is particularly attractive for power generation in geographical locations where low-quality, low-cost fuel, and limestone are readily available. The relatively recent acquisition of TRW by Northrop Grumman casts doubt on the potential for commercialization of this technology.

Acronyms and Abbreviations

AIDEA	Alaska Industrial Development and Export Authority
CCT	Clean Coal Technology Program
CFS	coal feed system
DE&S	Duke Engineering & Services
DOE	U.S. Department of Energy
DTP	demonstration test program
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
FCM	flash-calcined material
GVEA	Golden Valley Electric Association
HCCP	Healy Clean Coal Project
HGI	The Harris Group, Inc.
HHV	higher heating value
kW	kilowatt
LFS	limestone feed system
LOI	loss on ignition
μm	micrometer
MBtu	million British thermal unit
MW	megawatt
MWe	megawatt electric
MWh	megawatt hours
NO _x	nitrogen oxides
NSPS	new source performance standards
PM	particulate matter
PPA	post-project assessment
PSA	power sales agreement
ROM	run of mine
SDA	spray dryer absorber
S&W	Stone & Webster Engineering Corp.
SCR	selective catalytic reduction

SIPC	State Implementation Plan Call
SOW	statement of work
SO ₂	sulfur dioxides
SNCR	selective noncatalytic reduction

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