Section 5

Pulp Mill Integration Design & Cost

5.0 Pulp Mill Integration Design & Cost

5.1 Background

Section 4 dealt with the design and cost of the gasifier island. Its integration with the New Bern pulp mill will be discussed here.

As reported in Section 2, the New Bern pulp mill generates waste wood that is presently sold to a nearby power plant. Prior to 1991, the mill burned the waste wood (hog fuel) along with No. 6 oil in the No. 1 power boiler. Due to emission constraints, this practice was discontinued. The mill currently burns No. 6 fuel oil in its lime kiln, No. 1 power boiler and new No. 2 power boiler.

Two alternatives for returning the mill to biomass fuel were evaluated. The first option is gasification of the mill's hog fuel, sludge and additional wood residuals available from outside sources to produce a medium Btu content fuel gas to totally replace the No. 6 fuel oil. The oil firing capability would be maintained strictly as a backup in the event the gasification system was down for maintenance.

The second option, explained in more detail in Section 7, is to refurbish the No.1 power boiler and add the necessary emission control equipment to allow the unit to once again burn hog fuel. This option would utilize only the mill's hog fuel and would replace a portion of the No. 6 oil usage. The No.1 power boiler was designed to produce about 60% of its maximum steam generating capacity with wood. To achieve full output, the hog fuel must be supplemented with oil. With this option, the lime kiln and No. 2 power boiler would still utilize oil.

The mill's black liquor recovery boiler and the two power boilers produce steam at 850 psig/ 825°F. The steam is sent to a backpressure/extraction steam turbine generator. Process steam is obtained from a turbine extraction at about 155 psig and from the turbine exhaust at about 55 psig. The steam turbine is capable of generating 29 MW at full load. Since the mill process steam requirements vary with season and also with production, the mill steam generation is constantly adjusted to match the required process steam demand. Less steam generation means reduced throttle steam flow to the turbine generator, which results in less internal electric power generation and increased purchased power. This increases the mill's energy costs. This situation can be rectified by installing a small condensing steam turbine that would allow the mill to produce more electricity during periods of reduced process steam demand. Instead of reducing the steam production of the boilers to meet the process steam needs, the excess steam can be directed to the condensing steam turbine.

Consequently, the installation of a condensing steam turbine, in the 15 MW size range, has been included as part of each of the alternative biomass projects.

5.2 Integration Design Basis

The design and capital cost of the gasification system was developed by the Bechtel Corporation and reported in the previous section. Stone & Webster Engineering Corporation prepared the design for the balance-of-plant systems and the condensing steam turbine, and integrated the gasification system cost into a total project capital cost estimate.

The gasification process is designed to convert 73.2 tons/h of 50% moisture feed into 420 MMBtu/h of fuel gas (HHV basis). The gasification plant design considered here would be located on the current site of the bark storage pile. This pile and the stacking conveyor would be removed to make room for the gasifier installation. Figure 5–1 (Plot plan 07194-EM-1A) shows the layout of the Gasification Project.

Annual average ambient air conditions assumed for material balances, thermal efficiencies, and equipment sizing are:

- Dry bulb temperature 60°F
- Atmospheric pressure 14.7 psia

Cooling water requirements will be provided by a new cooling tower. A 90°F cooling water temperature is used for heat exchanger design.

Existing mill instrument air, process water, boiler feedwater, fire protection, and wastewater systems are adequate to support the project. Control of new systems will be incorporated into the existing mill DCS.

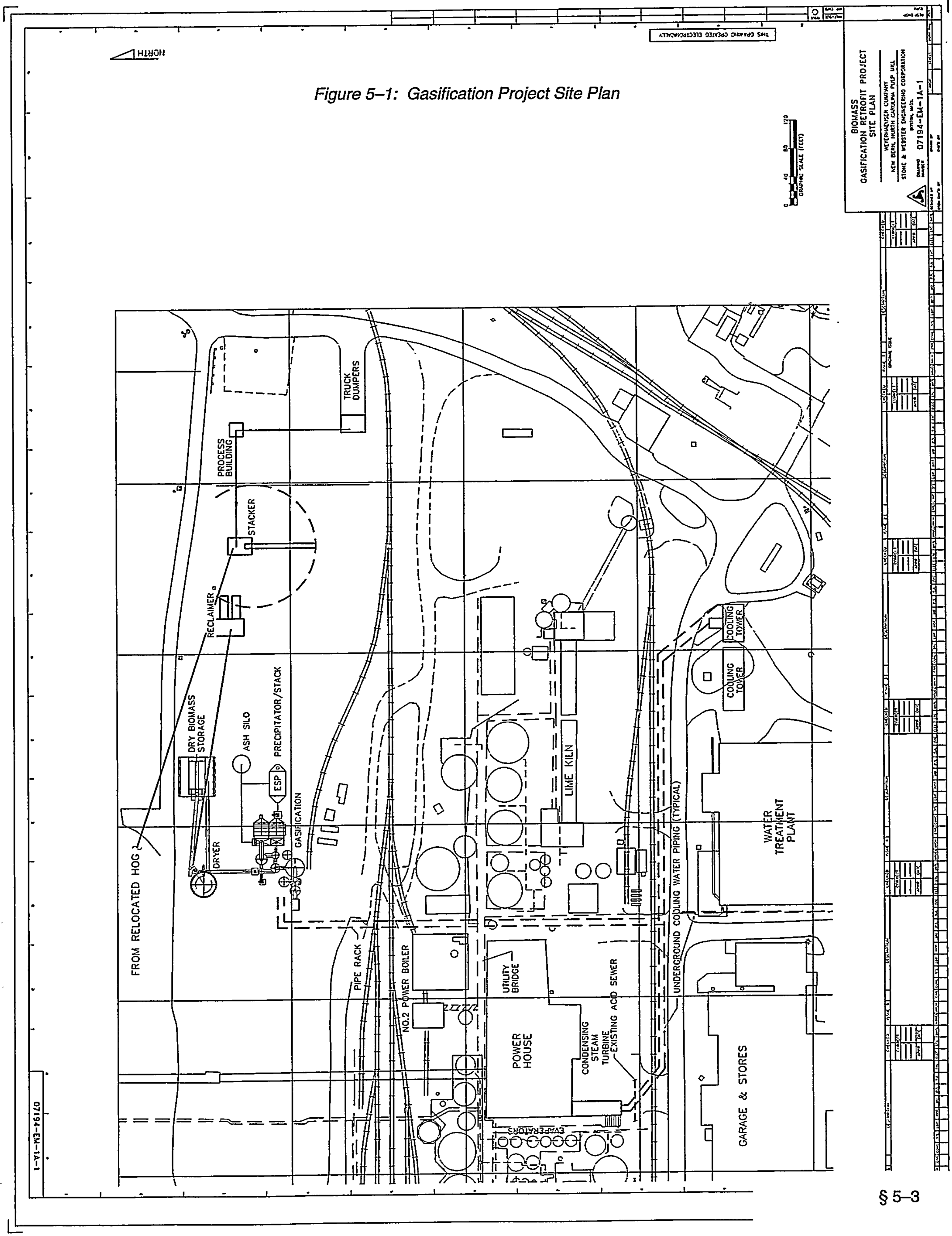
The gasification plant terminal points for interconnection to balance-of-plant systems are:

- Dryer feed (wet wood chip) bin outlet
- Dryer start up condenser non-condensables vent pipe to mill high-volume, low-concentration (HVLC) vent gas collection system
- Dryer start up condenser condensate outlet
- Scrubber product gas outlet
- Combustor heat recovery steam generator (HRSG) ash hopper outlet
- Combustor air heater flue gas outlet
- Scrubber blowdown outlet
- Product gas HRSG steam outlet
- HRSG drum blowdown piping to grade
- Local control (input/output) cabinets

The following utilities are supplied to the gasification plant battery limits:

- Instrument air
- Nitrogen
- High pressure (HP) steam for start up and dryer only operation
- No. 2 fuel oil
- Cooling water supply and return
- Process water
- Fire water
- Boiler feed water make up
- Electric power

Figure 5–1: Gasification Project Site Plan



5.3 Balance of Plant System Descriptions

5.3.1 Wood Receiving, Storage and Handling System

At full capacity, the gasification plant requires 73.2 tons/h of 50% moisture content wood biomass feedstock. This feedstock is obtained from several sources (see Section 2). The first source—providing approximately 30 tons/h—is the bark, rejects, sawdust and sludge produced in the mill complex. The other sources include chipped woodlot harvesting and thinning residuals as well as residuals from other wood processing sites in the area. All off-site feedstock is received via 20-ton capacity trucks.

The bark, rejects, sawdust, and associated material produced in the existing mill complex are consolidated in the existing hog fuel processing equipment and flow via a new belt conveyor (W-458) from the existing sizing station to the proposed wet fuel storage pile.

The existing bark sizing station must be relocated to allow proper alignment of the conveyors. This equipment operates two shifts per day (16 hours).

During normal operation, biomass delivery trucks arriving at the facility are weighed on a truck scale (W-451). The trucks then proceed to one of two redundant hydraulic truck dumpers (W-452A, B) which empty the truck contents into an above-grade, live-bottom, 5900 ft^3 receiving hopper near the gasification plant area. The truck dumpers are designed to tip the trucks, with the trailer still coupled to the cab, into the receiving hoppers. Each of the two redundant dumpers can receive up to seven trucks per hour. With the plant receiving trucks eight hours per day, and an average payload of about 20 tons of chipped biomass, about 130 tons per hour are dumped. Empty trucks return to the scale to obtain their tare weight.

The wood receiving, storage and handling system is shown in Figure 5–2 (PFD-G-002).

A belt conveyor (W-453) transfers feedstock from the two receiving hoppers to the process building, as shown in Figure 5–2. In the process building, the material is transferred onto a reversing belt conveyor (W-454). A magnetic tramp metal detection device mounted on this conveyor senses metal contamination in the feedstock, and reverses the conveyor to dump contaminated rejects to the ground. The dumped rejects are periodically removed by a front-end loader and discarded.

The process building contains a disk scalping screen (W-455) and a hammer-type hog (W-456). Material passing through the screen collects on a belt conveyor (W-457) and is transferred to the stacker (W-460). The oversize material that does not pass through the screen is directed to the hog for size reduction. The hog discharges the sized material onto the same belt conveyor for transfer to the stacker.

The sized biomass storage system includes a radial stacker (W-460) that combines the feedstock streams from the process building and from the relocated existing sizing station, and stacks them in a 21-day pile. A bulldozer works the pile on a regular basis to ensure consistent blending of the feedstocks. Material is reclaimed from the storage pile by two redundant drag chain conveyors (W-461A, B) via an inlet hopper, which is fed by a bulldozer. The reclaim conveyors feed the material onto the dryer feed belt conveyor (W-464).

The dryer feed belt conveyor discharges the material into an 1800 ft^3 surge hopper (W-465). Metering screws for feeding the dryer (included in the gasification system scope of supply) will be installed in the bottom of this hopper.

5.3.1.1 Equipment List

Truck Scale (W-451) – Heavy-duty truck scale, fully electronic, including desktop indicator, ticket printer, lightning protection, side rails, truck scale management system, and traffic light signals.

Truck Dumpers (W-452A,B) – Hydraulic truck dumpers. Rated for 35 ton maximum gross weight tractor-trailer trucks, 25 ton maximum payload, and for seven dumping cycles per hour. Each is furnished with above ground 5900 ft^3 receiving hopper, 160 tph capacity belt-type unloading conveyor, and transfer chute to W-453.

Process Building Feed Conveyor (W-453) – Covered, trough-type belt conveyor rated for 160 tph; includes 30 HP motor. Conveying distance: 250 ft horizontal, 45 ft vertical. Furnished with steel stringers and support trestles from foundations at grade, and with transfer chute to W-454.

Reversing Conveyor (W-454) – Trough-type belt conveyor with magnetic tramp-metal detector. Rated for 160 tph; includes 20 HP motor. Furnished with rejects chute and transfer chute to W-455.

Scalping Screen (W-455) – Rated for 160 tph, with sizes as follows:

+29 mm	7.9%
+22 mm	14.6%
+16 mm	23.0%
+10 mm	26.3%
+5 mm	15.9%
pan	12.3%

The screen is designed to pass all material smaller than 29 mm. Furnished with 15 HP motor and discharge chutes for oversized and undersized material.

Wet Fuel Hog (W-456) – Hammer-type with 300 HP motor. Rated for 16 tph (10% of feedstock flow from truck deliveries). Designed to reduce size to < 29 mm.

Wet Fuel Storage Pile Feed Conveyor (W-457) – Covered, trough-type belt conveyor, rated for 160 tph; includes 30 HP motor. Conveying distance: 250 ft horizontal; 45 ft vertical. Furnished with steel stringers and support trestles from foundations at grade. Also furnished with loading chute from W-455 and W-456.

Wet Feed Storage Pile Feeder from Existing Hogging Station (W-458) – Covered, trough-type belt conveyor, rated for 50 tph; includes 25 HP motor. Conveying distance: 750 ft horizontal; 50 ft vertical. Furnished with steel stringers and support trestles from foundations at grade. Also furnished with discharge chute for transfer of material to W-460.

Wet Fuel Stacker (W-460) – Rated for 210 tph; includes 30 HP motor. Conveying distance: 100 ft horizontal; 30 ft vertical. Furnished with telescoping discharge chute.

Wet Fuel Reclaim Drag Chain Conveyors (W-461A,B) – Rated for 75 tph; includes 100 HP motor. Designed to remove material from beneath storage pile and transfer it to W-464. Furnished with inlet hoppers/chutes. Inlet of reclaim conveyor is fed by a bulldozer from the storage pile.

Biomass Dryer Feed Belt Conveyor (W-464) – Covered, trough-type belt conveyor, rated for 75 tph; includes 40 HP motor. Conveying distance: 700 ft horizontal; 65 ft vertical. Furnished with loading chute from W-461A, B.

Dryer Feed Surge Hopper (W-465) – 5 ft wide by 18 ft long with an overall height of 20 ft. Furnished with inlet hood from W-464.

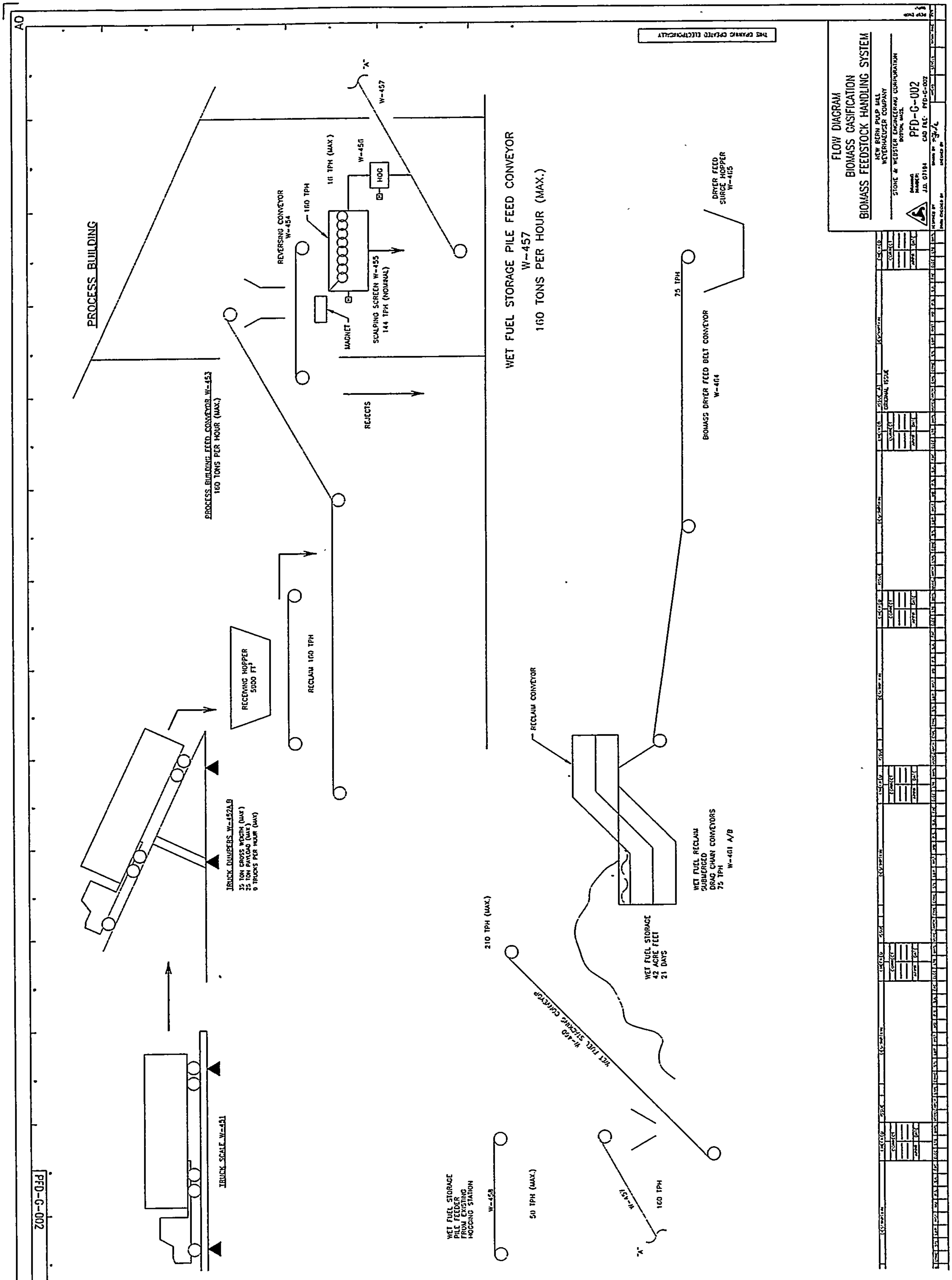


Figure 5–2: Biomass Feedstock Handling System

5.3.2 Ash Collection and Removal System

The ash leaves the gasification process with the combustor flue gas. This flue gas contains approximately 4,700 lb/h of biomass ash and sand. It is expected that at least 50% of this particulate matter (approximately 2,400 lb/h) will drop out of the flue gas stream in the combustor HRSG.

Approximately 59,000 acfm of 300°F flue gas leaving the air heater passes through an electrostatic precipitator (FGS-ESP1) for removal of the remaining flyash to meet emission standards. The cleaned flue gas will be discharged through a metal stack (FGS-STK1) 150 feet above grade.

The ash collection and removal system is shown in Figure 5–3 (PFD-G-003).

Ash at approximately 800°F falls by gravity from the combustor HRSG ash hopper into a water-jacketed screw conveyor (AHS-CNV1) where it is cooled to below 400°F with 65 gpm of cooling water. The ash is discharged from the screw conveyor into a double flap airlock (AHS-LK1) to maintain 16.2 psia pressure in the combustor HRSG. The airlock feeds the ash transfer conveyer (AHS-CNV4), a drag chain conveyor that transports the ash to the storage silo (AHS-SILO1).

The ash removed in the electrostatic precipitator collects in two trough hoppers and falls by gravity into two ash collecting conveyors (AHS-CNV2A,B). These dry drag chain conveyors transport the ash to the precipitator transfer conveyor (AHS-CNV3), a dry drag chain conveyor which discharges into a double flap airlock valve (AHS-LK2) designed to maintain the 15.7 psia pressure in the precipitator. The airlock directs the ash onto the ash transfer conveyor (AHS-CNV4) where it joins the HRSG ash and is deposited in the storage silo.

The ash storage silo (AHS-SILO1) is sized for 24 hours of maximum gasification process ash production, assuming a minimum ash density of 20 lb/ft^3. The actual ash density may be as high as 60 lb/ft^3, providing over 3 days of ash storage. The silo is designed to allow a truck to drive under the discharge hopper. The discharge hopper is equipped with an ash conditioning unit (AHS-W1) that wets the ash to increase its density for disposal.

5.3.2.1 Equipment List

Electrostatic Precipitator (FGS-ESP1) – Designed for 64,900 acfm (10% overdesign) flue gas flow at 300°F and 15.7 PSIA with a inlet loading of 8 grains/ACF; Removal efficiency = 99.2%.

Stack (FGS-STK1) – Dual wall steel stack; 150 ft high; 4.5 ft ID

Ash Cooling Conveyor (AHS-CNV1) – Design capacity 4 tph; Design pressure 16.2 PSIA; screw type with indirect water cooling; Ash inlet temperature = 800°F; Ash outlet temperature = 400°F (max); Conveyor overall length = 35 ft; 3 HP variable speed motor.

Precipitator Collecting Conveyors (AHS-CNV2A,B) – Design capacity 1.2 tph; 2x12 single strand drag chain with 37 ft horizontal sprocket centers; design pressure = 15.7 psia; 2 HP motor.

Precipitator Transfer Conveyor (AHS-CNV3) – Design capacity 2.2 tph; 2x12 single strand drag chain with 37 ft horizontal sprocket centers; design pressure = 15.7 psia; 2 HP motor.

Ash Transfer Conveyor (AHS-CNV4) – Design capacity 4.6 tph; 2'-6" wide double strand design with 167 ft true socket centers; horizontal run of 64 ft + 103 ft inclined at 40° to top of ash silo; 7.5 HP motor.

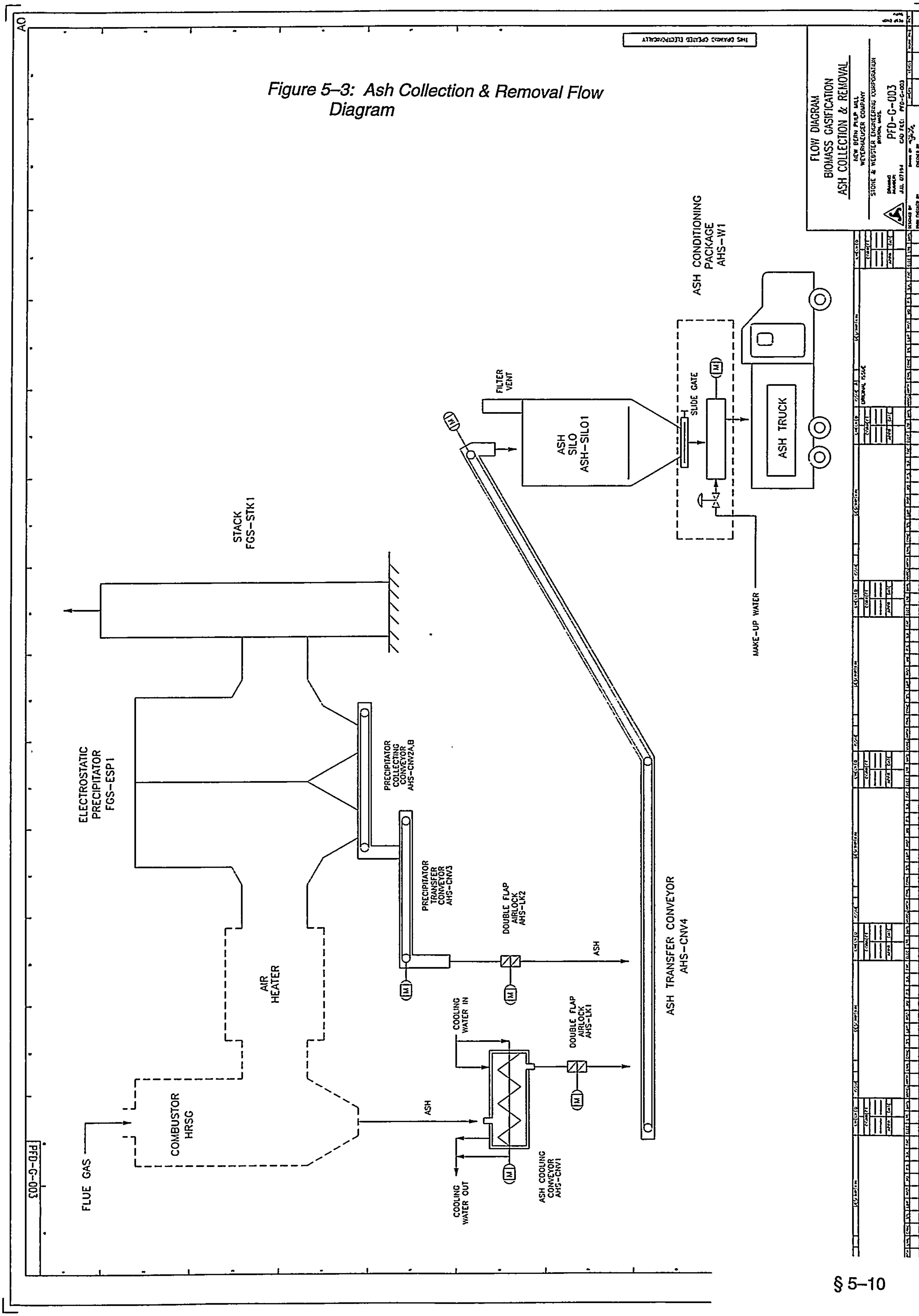
Double Flap Airlock (AHS-LK1) – Design capacity = 4 tph; design pressure = 16.2 psia

Double Flap Airlock (AHS-LK2) – Design capacity = 2.2 tph; design pressure = 15.7 psia

Ash Silo (AHS-SILO1) – Steel silo 26 ft diameter with 60° bottom cone; 40 ft overall height with bottom outlet 20 ft above grade.

Ash Conditioning Unit (AHS-W1) – Designed for 30 tph; maximum ash inlet temperature = 400°F; includes all valves, fittings feeders from silo bottom outlet through truck loading outlet.

Figure 5–3: Ash Collection & Removal Flow Diagram



5.3.3 Product Gas System

The product gas system receives cleaned product gas from the gasification system scrubber discharge; cools the gas to reduce the water content; compresses the gas; distributes the gas to the mill's No. 1 power boiler, No. 2 power boiler and the lime kiln; and combusts the gas in these units. The product gas system is shown in Figure 5–4 (PFD-G-004).The gasification system produces 60,461 lb/h (17,691 acfm at 15.45 psia/125°F) of medium Btu heating value fuel gas (MBG). The gas composition is shown in Table 5-1, and the modifications required to utilize the product fuel gas are indicated in Table 5–2.

COMPONENT	VOLUME %	WEIGHT %
Hydrogen	14.10	1.22
Methane	14.46	10.02
Ethane	0.85	1.04
Ethylene	5.26	6.37
Carbon Monoxide	41.57	50.36
Carbon Dioxide	11.04	21.02
Water Vapor	12.72	9.89

Table 5-1: Product Gas Composition

The gas leaving the scrubber is saturated. The gas is fed to a compressor (PGS-C1) which compresses the product gas to a pressure of 15 psig. The compressed gas is distributed via a 12 inch nominal diameter Schedule 20 pipe header to the three product gas users.

Equipment	Modifications Required
Lime Kiln	Change the oil-fired burner to a fuel gas/oil burner with a heat input of 105 MMBtu/h on either gas or oil. The new burner includes a burner management system. The existing fuel oil piping train will be retained. The fuel gas line to the lime kiln is 8 inch nominal diameter.
No. 2 Power Boiler	Change the multi-fueled (oil, low Btu gas, high concentration low volume vent gases) dual burner system to a dual fired burner capable of burning these fuels as well as medium Btu fuel gas(MBG). The MBG capacity of the burner will be 230 MMBtu/h. The existing fuel oil, low Btu gas, vent gases piping trains will be retained. The existing burner management system will be expanded to include the new fuel gas. The MBG feed line to the No. 2 power boiler is 10 inch nominal diameter
No. 1 Power Boiler	Replace the six existing No. 6 oil-fired burners with six dual fuel MBG/Oil fired burners. Each burner has a capacity of 75 MMBtu/h. The existing Forney burner management system will be replaced with a new burner management system. The feed line to the No. 1 power boiler will be 10 inch nominal diameter, reducing to 6 inch diameter for each of the six burner valve trains. The existing fuel oil piping trains will be retained

Table 5–2: Required Modifications to Utilize Product Gas

5.3.3.1 Equipment List

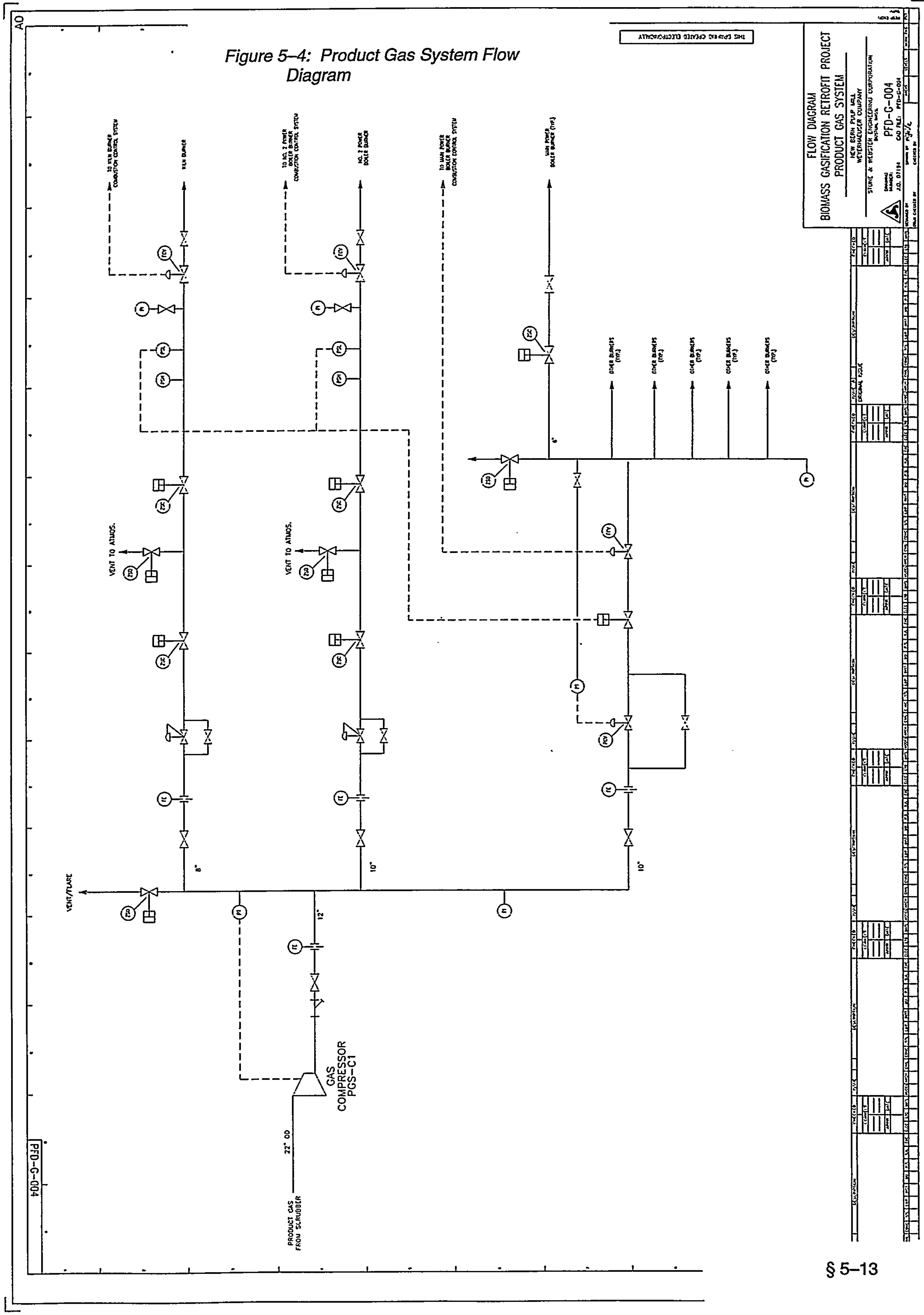
Compressor (PGS-C1) – Single stage integrally geared centrifugal compressor package including lube oil system (twin filters, twin pumps, SS downstream of filters), controls (capacity and protection), 1375 HP 4160V motor, dry gas seal, moisture separator, accumulator-receiver.

Lime Kiln Burner (PGS-LKB1) – 105 MMBtu/h dual zone burner burning MBG in the annulus zone and #6 fuel oil in a center gun including a propane/electric pilot, dual fuel management system, flame scanner and primary air fan.

No. 1 Power Boiler Burners (PGS-PB1B1 through PGS-PB1B6) – Six 650 MMBTU/h dual fuel MBG/#6 FO burners with main #6 fuel oil guns, gas spuds, #2 fuel oil ignitors, fuel valve trains, burner management system and spare main oil guns.

No. 2 Power Boiler Burner Modifications (PGS-PB2B1) – One set of 274 MMBtu/h burner gas spuds for retrofit to the existing multifuel burner including MBG valve train and burner management modifications.

Figure 5–4: Product Gas System Flow Diagram



5.3.4 *Condensing Steam Turbine System*

The condensing steam turbine system includes the turbine generator, its control and auxiliary systems, main steam piping from high pressure steam header to the turbine throttle, extraction piping to mill medium pressure and low pressure steam headers, a surface condenser, a condenser air removal system, condensate pumps and condensate piping to existing mill deaerator.

The condensing steam turbine system is shown in Figure 5–5 (PFD-001).

The turbine generator (CST-T1) is a nominal 15 MW machine. Steam is admitted to the throttle at 850 psig/825°F. Steam can be extracted from two stages of the turbine, if desired, to supply the mill's medium pressure (155 psig) and/or low pressure (55 psig) steam headers. The turbine full load exhaust flow with no extractions and a condensing pressure of 3 inches Hg is 140,000 lb/h. The extractions are uncontrolled to minimize the turbine cost. Since external controls are employed for the extraction flow and pressure, an exhaust temperature control system is used to ensure that the flow to the exhaust is sufficient to prevent overheating.

The steam exiting the turbine is condensed in a surface condenser (CST-CND1) and the condensate is pumped using one of two 100% capacity pumps (CST-P1A/B) to the existing mill deaerator. The condenser design duty is 132.5 MMBtu/h. The design cooling water flow rate is 8,823 gpm based on a 30°F ΔT.

Each condensate pump is sized for a maximum flow of 280 gpm. Since the condensing steam turbine will normally be operating at partial load, the condensate pump discharge will be recycled to the condenser hotwell as required to maintain a minimum hotwell level. Steam ejectors are used for condenser air removal. The system employs a hogging ejector for start up and a holding ejector for normal operation.

5.3.4.1 Equipment List

Turbine generator (CST-T1) – 15 MW nominal size, with two uncontrolled extractions at 155 psig and 55 psig, exhausting at 3 inches Hg; 13.8 kV totally enclosed water to air-cooled generator.

Surface Condenser (CST-CND1) – Heat transfer surface = 18,319 ft^2; 5/8" BWG 304 stainless steel tubes; single pressure, 2-pass.

Condensate Pumps (CST-P1A/B) – 280 gpm horizontal centrifugal pump with 30 HP motor

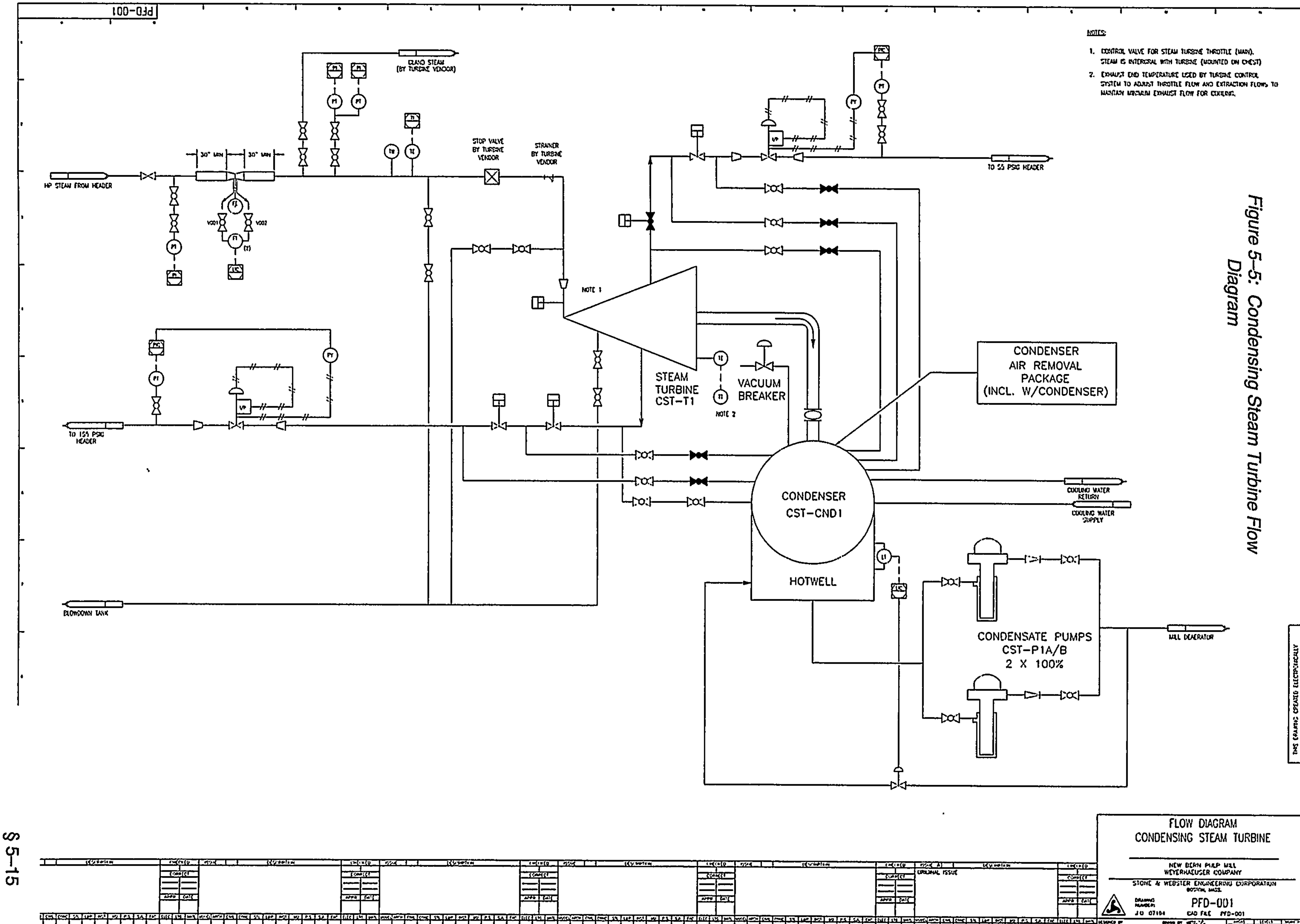


Figure 5-5: Condensing Steam Turbine Flow Diagram

5.3.5 Cooling Water System

The cooling water system is shown on Figure 5–6 (PFD-G-005). The system is designed to meet the following cooling requirements:

Product fuel gas scrubber cooler	6,484 gpm @ 25°ΔT
Product gas compressor lube oil cooler	30 gpm @ 20°ΔT
Gasifier	300 gpm @ 20°ΔT
Condensing steam turbine condenser	8,823 gpm @ 30°ΔT
Condensing steam turbine lube oil cooler	200 gpm @ 20°ΔT
Condensing steam turbine generator cooler	260 gpm @ 20°ΔT
Combustor ash cooling conveyor	65 gpm @ 20°ΔT
Dryer vent condenser	5,600 gpm @ 20°ΔT
Nitrogen plant air compressor	10 gpm @ 20°ΔT

The normal circulating water flow is 16,172 gpm since the dryer vent condenser is only in service if the dryer needs to be operated when the gasification plant is shut down (i.e., to build up inventory of gasifier feedstock).

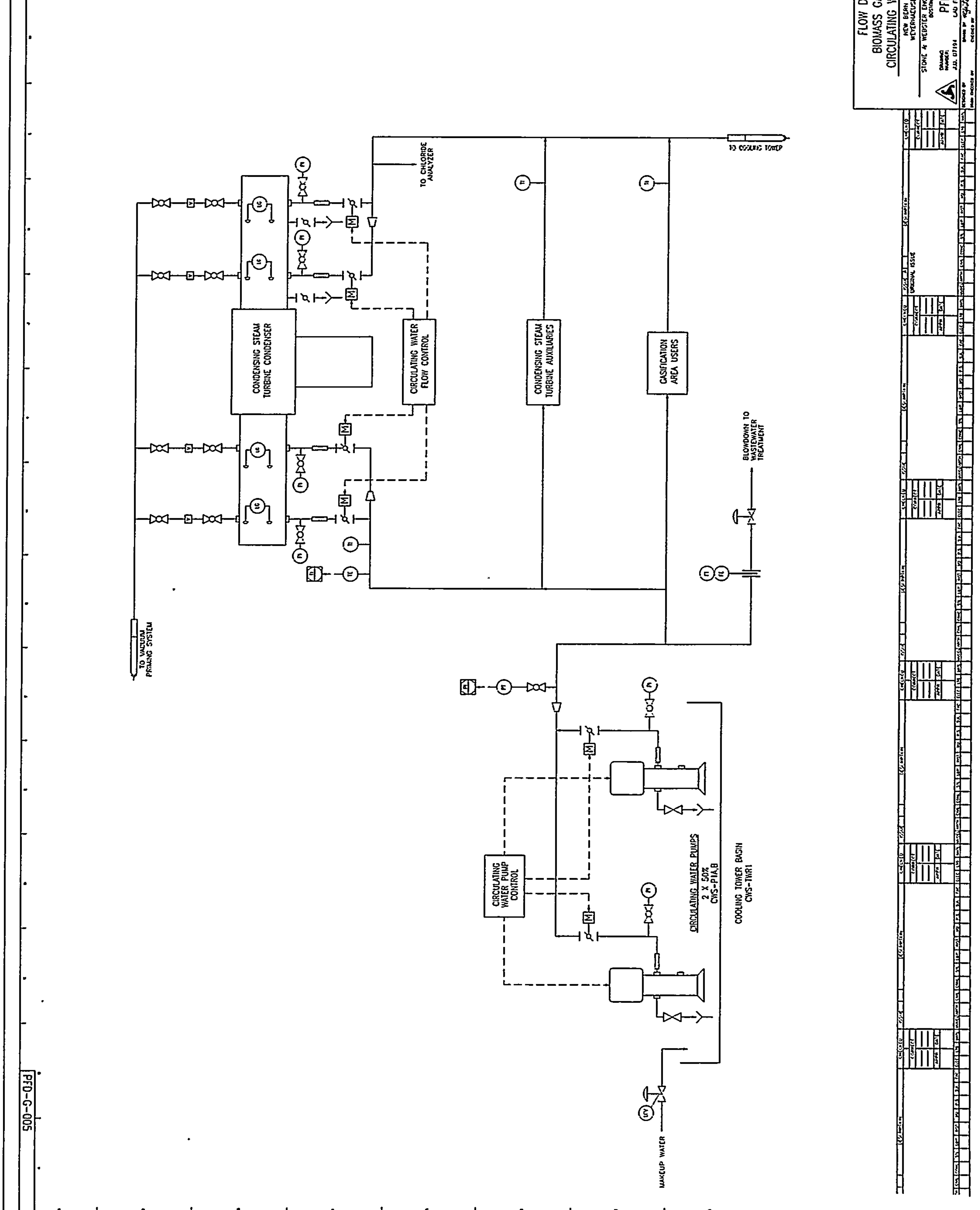
The system is a closed cycle utilizing a two cell mechanical draft cooling tower (CWS-TWR1). Two 50% capacity (8,100 gpm) circulating water pumps (CWS-P1A,B) take suction from the cooling tower basin and distribute the water to the specified users and back to the cooling tower fill. The cooling tower blowdown rate is established to maintain the required water solids levels. The make up water to the tower is controlled by the water level in the basin.

5.3.5.1 Equipment List

Cooling Tower (CWS-TWR1) – Two cell (each cell is 36 ft x 36 ft) counterflow mechanical draft cooling tower with single speed 125 HP fans; tower cooling duty = 223 MMBtu/h

Circulating Water Pumps (CWS-P1A,B) – 8,100 gpm vertical centrifugal pump with 300 HP motor.

Figure 5–6: Circulating Water Flow Diagram



5.3.6 Other Utility/Infrastructure Requirements

Extending existing mill utility systems such as process water, compressed air, wastewater and fire protection to the gasification process is straightforward. The most significant integration involves the mill steam generation and distribution system. This system must provide boiler feed water, receive and provide steam and receive steam condensate. The interconnections between this system and the gasification plant are shown in Figure 5–7 (PFD-G-006).

5.3.6.1 Nitrogen System

The gasification system uses up to 75 scfm of nitrogen for continuous inerting/ purging. In addition, 26,900 scf are required for a start up or shutdown. A nitrogen purity of 98% is acceptable.

A packaged membrane nitrogen generation system is employed. The system is capable of providing up to 5700 normal cubic feet per hour of 98% purity nitrogen. A 100 HP air compressor supplies air to the membranes. The membranes require 175 psig air. The operating pressure of the system is based on an economic tradeoff between membrane cost and air compressor electricity consumption. The nitrogen leaves the membranes at 150 psig.

For the start up and shutdown purging requirements, a liquid nitrogen storage and vaporization system will be leased. The storage tank holds 6,000 gallons and is 8 feet in diameter by 26 feet high. The system is sized for one start up and shutdown.

5.3.6.2 Instrument Air

The gasification system utilizes 50 scfm of instrument air. The total instrument air requirement for the project is estimated to be less than 75 scfm. The existing mill instrument air system has approximately 200 scfm of excess capacity, so a new system is not provided.

5.3.6.3 Process Water Make up to Gasification Plant and New Cooling Tower

The gasification system does not have any continuous requirements for process water. Nonetheless, a connection to the mill's process water distribution system will be provided for intermittent requirements such as the initial filling of the scrubber.

Mill process water is used for cooling tower makeup. The makeup water flow rate to the new cooling tower will be about 567 gpm at full load operation of both the gasification plant and the condensing steam turbine. With the gasification plant at full load and the condensing steam turbine at half load, the cooling tower make up rate would be reduced to about 400 gpm. A connection will be provided from the process water distribution system to the cooling tower make up water line.

5.3.6.4 Boiler Feedwater Make up to Gasification Plant

The product gas cooler requires 131 gpm of boiler feed water at 1000 psia. The combustor heat recovery steam generator requires 168 gpm of boiler feed water at 475 psia. A high pressure feed water line from the existing mill feed water system will be provided to the gasification plant battery limits.

5.3.6.5 HP Superheated Steam Connection

The gasification plant requires steam to start up and to operate the dryer to build up dry wood inventory when the gasifier is shut down. During normal operation the gasification system product gas cooler will produce 65,356 lb/h of high pressure superheated steam.

An interconnection from the existing mill high pressure steam header to the gasification plant is provided to meet these requirements.

5.3.6.6 Condensate Return from Gasification Plant to Mill Deaerator

A condensate return pipe will be provided from the dryer heating steam condensate pump to the mill condensate collection system.

5.3.6.7 Blowdown from HRSG Drums

An atmospheric flash tank is located in the gasification area to receive intermittent and continuous blowdowns from the product gas HRSG steam drum and the combustor HRSG steam drum. The water remaining after flashing will be cooled in a heat exchanger using cooling water and discharged to the mill process sewer.

5.3.6.8 Wastewater

Most of the water in the wood fed to the gasifier is condensed in the product gas scrubber. Approximately 141 gpm of water will be discharged to the mill wastewater treatment system.

When the dryer is operated with the gasification system shut down, the moisture removed from the wood is condensed and sent to the mill wastewater treatment plant. The maximum flow is approximately 111 gpm.

The blowdown from the new cooling tower is expected to be between 900 and 1200 gpm, depending upon whether 5 or 4 cycles of concentration is desired. The existing mill wastewater treatment system is capable of handling these additional wastewater loads.

5.3.6.9 Vent VOC Collection

The moisture removed in the dryer will contain volatile organic carbon (VOC) compounds from the wood. This contaminated steam is normally consumed in the gasifier. However, if the dryer is operated while the gasifier is shut down and the water vapor is condensed, the non-condensable gases will contain VOCs that can not be emitted to the atmosphere. The mill has two vent collection systems which utilize vent gases in the No. 2 power boiler. The dryer exhaust condenser vent will be connected to the existing mill HVLC non-condensable gas vent collection system.

5.3.6.10 Start Up Fuel

The gasifier and the combustor require approximately 86 MMBtu/h of fuel for start up. This requirement will be provided with No. 2 fuel oil (approximately 10 gpm). A 20,000 gallon tank and forwarding pumps will be located in the gasifier area.

5.3.6.11 Fire Protection

A fire water line from the existing mill fire loop will be provided to serve the dryer/gasification area.

5.3.6.12 Electrical Interconnections

The generator output from the 15 MW condensing steam turbine will be connected to the mill's 13.8 kV bus. The biomass gasification retrofit project and condensing steam turbine project will utilize between 4.7 and 5.4 MW of electricity on a continuous basis.

A 13.8 kV/4160 volt transformer will be provided to feed a 4160 volt bus to supply electricity to the following major loads which will employ 4160 volt motors:

Combustor Blower	1,673 kW
Gasifier Start Up Blower	1,431 kW
Dryer Fan	998 kW
Product Gas Compressor	1,044 kW

A 4160 volt/480 volt transformer will be provided to supply a 480 volt load center to service the remaining gasification plant loads including the wood yard, electrostatic precipitator, ash handling and nitrogen systems. These loads are summarized in Table 5–3.

		Normal	Startup/ Shutdown
		kWe	kWe
Gasification Process	Combustor Blower	1,673	
	Gasifier Blower		1,431
	Dryer Fan	998	
	Other Dryer	110	
	Pumps	59	
	Conveyors	166	
	Rotary Feeder	45	
	Feed Screw	7	
	Misc.	20	
	Gasification Subtotal	3,079	kWe
Balance of Plant	Fuel Gas Compressor	1,044	
	Condensate Pump	18	
	Ash Handling	16	
	Wood Handling	604	
	Nitrogen	75	
	Circ Water Pumps	280	
	Cooling Tower Fan	100	
	Electrostatic Precipitator	46	
	Steam Turbine Auxiliaries	19	
	Misc.	44	
	BOP Subtotal	2,246	kWe
	TOTAL	**5,325**	**kWe**

Table 5–3: Gasification Project Electrical Load List

The condensing steam turbine project loads and the new cooling water system will be connected to the existing mill 480 volt load centers.

5.3.6.13 Control System

The mill has a Rosemount distributed control system (DCS). The system will be expanded to allow control of the gasification plant and condensing steam turbine from the existing mill power and recovery control room. Two operator consoles will be added to the control room.

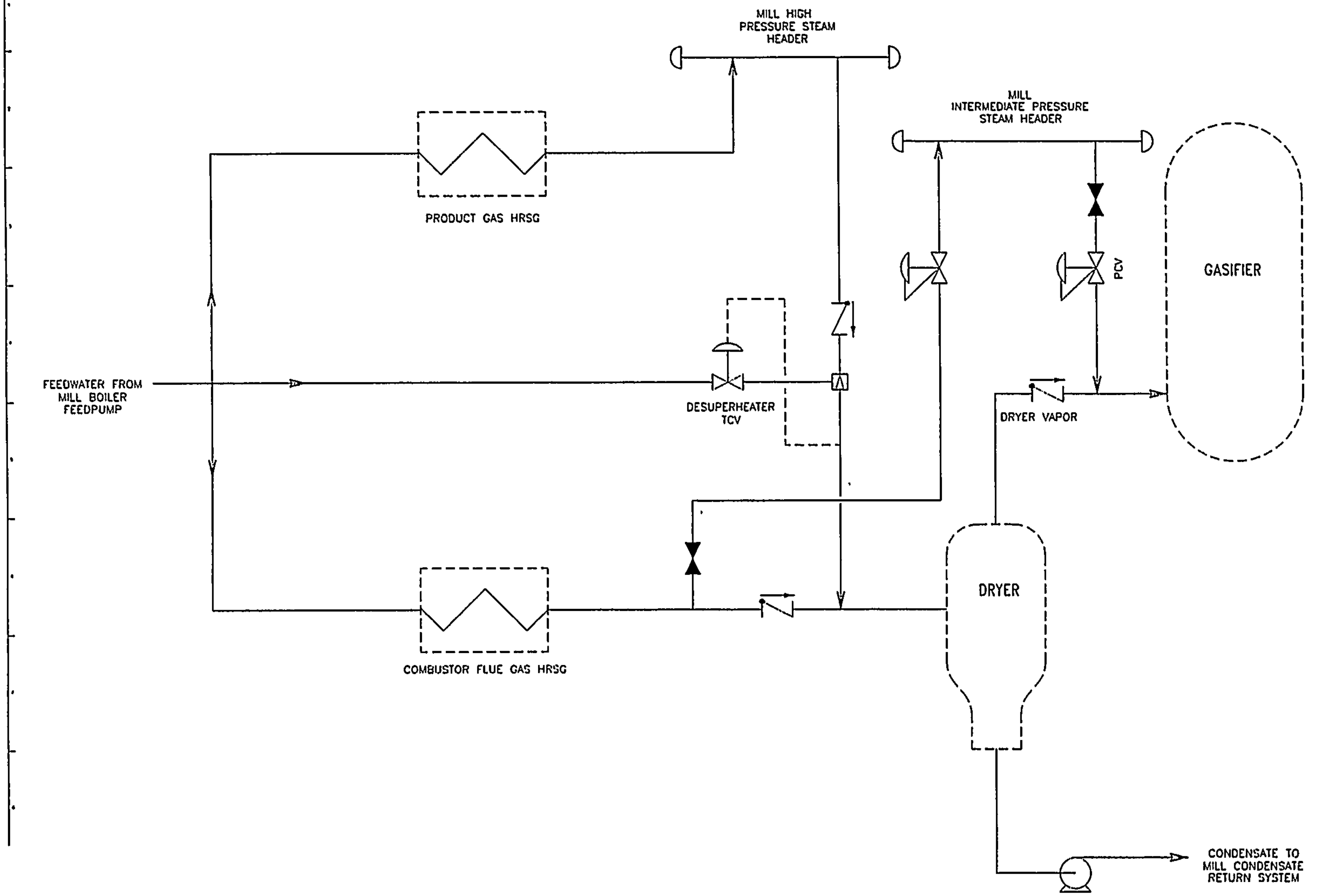


Figure 5–7: Gasifier Steam System Flow Diagram

FLOW DIAGRAM
BIOMASS GASIFICATION RETROFIT PROJECT
GASIFIER STEAM SYSTEM

NEW BERN PULP MILL
WEYERHAEUSER COMPANY

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

PFD-G-006

5.4 Capital Cost Estimates

Three capital cost estimates were prepared. Two of the estimates are for the gasification retrofit project at the Weyerhaeuser New Bern Pulp Mill and include a condensing steam turbine installation. The first estimate, titled the "Nth Plant Design", represents the cost for a mature gasification technology design. It is based upon expectations for the technology which must be verified. The second estimate, titled the "Next Plant Design", includes the higher costs for the first commercial application of the gasification technology. To provide information for others to evaluate the economics of wood gasification, a third estimate for a generic or non-site specific gasification plant (Nth plant design) was developed.

Bechtel developed the estimates for the gasification process including the dryer. Stone & Webster prepared the costs for the condensing steam turbine and balance of plant and assembled the complete project estimates.

5.4.1 Estimating Approach

The estimating approach and the engineering information provided to support the gasification process estimate are consistent with an Electric Power Research Institute (EPRI) Class II, Preliminary Estimate, as defined in EPRI's *Technical Assessment Guide*, (EPRI TR-102275-VIR7, Volume 1: Rev. 7, June 1993).

The estimates were developed using flowsheets and site plan/elevation sketches. Process equipment sizes and/or capacity ratings, and fabrication materials/methods were defined. Budget quotes were obtained for major equipment items. Most of the utilities piping outside of the gasification area were sized and estimated based on quantities developed from material takeoffs using the site plan. The rest of the items and bulk materials were estimated using in-house estimating databases. Bechtel checked bulk materials for the gasification system by comparing ratios of bulk material purchase order costs versus major equipment purchase order costs against actual cost ratios from a similar facility—the gasifier and quench units in the Cool Water Coal Gasification Demonstration Project.

These estimates should be characterized as near conceptual, having an accuracy range of ± 25-30%.

5.4.2 Estimating Basis and Assumptions

The capital cost estimate was developed based on the following assumptions:

- Cost data are based on a January 2000 price level.
- Owners' costs are not included.
- Cost of permits, applications and inspections by governmental bodies not included.
- No clearing and grubbing required.
- No mass earthwork; no allowance for site remediation.
- Excavated material is suitable for structural backfill.

- Water table is below the lowest level of excavation; no subdrains or special drainage provisions; however, standard curbs and Udrains are provided for the surface facilities and a sump pump for the basement.
- No storm drains. Process area will be graded and paved to direct the runoff to perimeter road gutters.
- Paving is included only for access to ash silo and new wood truck receiving area.
- No material will be disposed of off site.
- There is no provision for sales tax.
- All major foundations rest on precast concrete piles with average length of 60 LF.
- A 120 foot long pipe/utility bridge is provided to link the Fuel Dryer and Gasification equipment with the rest of the plant.
- Electrical cables are routed in tray supported from pipe/utility bridge (no underground routing).
- The only underground systems are cooling water to/from the main mill pipe bridge to the condensing steam turbine condenser, electrical grounding and the firewater system.
- No allowance for price/wage escalation has been provided. Project duration would probably be about 24 months.
- Engineering, Procurement, and other management/administration costs ("Home Office Cost") have been estimated as a percentage of the constructed cost of the plant.

5.4.3 Estimate Components

5.4.3.1 Direct Field Material Costs

Direct field material costs are for permanent physical plant facilities. They include the following elements:

- **Equipment.** Equipment includes all machinery used in the completed facility, such as boilers, rotating machinery, heat exchangers, tanks, and vessels.
- **Material.** Materials include concrete, steel, building materials, pipe and fittings, valves, wire and conduit, instruments, insulation, and paint used in constructing the completed plant.
- **Freight.** Freight to the jobsite is included.

5.4.3.2 Direct Field Labor Costs

The components of direct field labor costs are labor manhours and the composite labor wage rate.

5.4.3.3 Direct Subcontract Costs

Direct subcontract costs are those for equipment, materials, and services furnished by the subcontractors, including installation labor costs and related indirect field costs.

Major items that were estimated as subcontract costs include:

- Dryer assembly
- Condensing steam turbine refurbishment and reinstallation
- Cooling tower
- Electrostatic precipitator
- Ash handling equipment
- Refractory
- Insulation, painting, and personnel protection

5.4.3.4 Indirect Field and Home Office Engineering Costs

Indirect field costs are costs that cannot be directly identified with any construction operation related to specific plant facilities but that support the general construction operation.

These costs for indirect labor and materials include allowances for the following items:

- Miscellaneous construction services (labor) covering cleanup, maintenance of tools and construction equipment, security, surveying and testing.
- Temporary construction.
- Materials including temporary buildings and roads, utilities and services, scaffolding, testing, construction equipment, tools and consumables.
- Construction non-manual personnel.

Home office engineering manhours and other home office services cover the expenses of the following items:

- Labor for engineering design, procurement, technical services, administrative support, and project management services
- Office expenses such as materials, telephone, reproduction and computer costs, and travel

5.4.3.5 Process Contingency

A process contingency is not included in the Nth Plant estimate because by definition the Nth Plant represents the mature, proven technology. The Next Plant gasification design is based on a more conservative equipment/system design. Nonetheless, because of the early state of development of the technology, a process contingency is also included in the estimate to provide for modifications that may be required to achieve acceptable performance.

To determine the overall process contingency, Bechtel evaluated the potential uncertainties of each major system/equipment item and assigned a contingency to the total direct cost for each item. The contingencies ranged from 0% to 100%. The resulting total contingency is $3,550,000, which is 13.4% of the direct cost of the gasification system. The EPRI Technical Assessment Guide suggests that the percentage be between 20 to 35% for a process for which small pilot scale data is available and between 5 to 20% if there is an operational full-size module. The gasification technology state of development is somewhere in between these two stages. Consequently, a process contingency of 13.4% is reasonable.

5.4.3.6 Project Contingency

The Weyerhaeuser Standardized Project Process recommends using a project contingency between 8 to 10%. This contingency level is acceptable for small capital cost projects. The EPRI Technical Assessment Guide recommends the project contingency be based upon the level of design/estimating completed. This project meets the definition of a Class II estimate for which a 15 to 30% project contingency is recommended. A contingency equal to 15% of the total direct plus indirect cost is applied to the Nth plant estimate. However, for the Next Plant estimate, the project contingency was increased to 25%.

5.4.4 Nth Plant Design at New Bern Cost Estimate

The total installed cost for the biomass gasification retrofit project at New Bern based on the Nth Plant Design is $55.8 million as shown in Table 5-4.

The Nth Plant Design is a mature design consistent with good engineering practice. The design includes prudent equipment sparing. However, optimum technology performance (not yet demonstrated) is assumed, which would result in minimum equipment sizing.

5.4.5 Next Plant Design at New Bern Cost Estimate

The project cost based upon the Next Plant Design is $67.9 million as shown in Table 5–5.

The Next Plant Design incorporates conservatism recommended by Bechtel to reduce technical risks. The fuel handling system includes a round-robin conveyor system to move dried fuel continuously from the dryer to the feed bin with overage going on to the dried chip storage bin. A conveyor is provided not just from the storage bin back to the dryer as is used in the Nth Plant Design, but all the way to the feed bin. This provides redundancy in the "S" conveyor moving material to the feed bin. Two feeds with their associated equipment are provided into the gasifier to provide for both redundancy and to ensure proper mixing between the sand and fuel in the bottom of the gasifier. The capacities of the sand and magnesium oxide (MgO) silos are increased in case the sand consumption is higher than expected. A secondary cyclone is added to further reduce solids carryover to the tar cracker and scrubber. Allowances were included for a taller gasifier/combustor structure, for additional instrumentation and for additional start up support. Finally, a process contingency is added to cover other potential equipment modifications.

The impact of the Nth versus Next gasification plant design on the balance of plant costs is negligible.

5.4.6 *Generic Nth Plant Gasification Plant Cost Estimate*

The generic gasification plant design is the same capacity as the New Bern design (420 MMBtu/h of fuel gas production), but it does not include the condensing steam turbine project. Specifically, the following modifications were made to the New Bern design to make it generic:

- Condensing steam turbine project was deleted.
- Cooling tower and cooling water pump capacities were reduced to satisfy only the gasification plant cooling requirements.
- Natural gas was assumed to be available for the gasifier start up.
- A totally independent wood receiving, storage and handling system is provided.
- A gasification plant control building is provided.
- The gasification plant battery limits terminate at the fuel gas compressor discharge, i.e., the fuel gas is available at 15 psig pressure, but no distribution/combustion equipment is provided.

The generic gasification plant must still be integrated into an existing steam generation facility (for office/laboratory/sanitary facilities, fire water supply, service water, boiler feedwater, start up steam, a use for the steam produced in the product gas HRSG, wastewater treatment and 4160v/480v electrical supply.

The generic gasification plant capital cost is $49.9 million as given in Table 5–6.

5.5 Operating & Maintenance Costs

5.5.1 *Staffing Requirements*

Additional Control Room Operators	1 per shift	= 4
Wood yard	1.5 per shift	= 6
Truck Unloading	1 for two shifts weekdays	= 2
Gasifier Area Roving Operators	1.5 per shift	= 6
	TOTAL	**18**

TABLE 5–4

BIOMASS GASIFICATION RETROFIT PROJECT CAPITAL COST ESTIMATE
Nth PLANT DESIGN

Basis: January 2000

Item	Material	Labor	Subcontract	Total Cost
PLANT SYSTEMS				
Wood Drying/Gasification	9,941,000	424,000	8,622,000	$18,987,000
Gasification Utilities	250,000	10,000		$260,000
Condensing Steam Turbine	1,678,000		1,280,000	$2,958,000
Wood Handling	2,315,000	350,000		$2,665,000
Electrostatic Precipitator/ash Handling	1,504,000		800,000	$2,304,000
Product Gas	1,615,000		290,000	$1,905,000
Cooling Water	410,000	163,000		$573,000
Switchyard/Electrical	80,000		91,000	$171,000
Distributed Control	270,000		75,000	$345,000
Subtotal	**$18,063,000**	**$947,000**	**$11,158,000**	**$30,168,000**
BULK MATERIALS				
Site Improvements	3,000	65,000		$68,000
Gasification/Drying	3,847,000	1,395,000	158,000	$5,400,000
Gasification Utilities	631,000	315,000		$946,000
Condensing Steam Turbine	195,000	189,000		$384,000
Wood Handling	149,000	55,000		$204,000
Ash Handling	119,000	75,000		$194,000
Product Gas	165,000	129,000		$294,000
Cooling Water	517,000	258,000		$775,000
Switchyard/Electrical	68,000	50,000		$118,000
Distributed Control	20,000		20,000	$40,000
Subtotal	**$5,714,000**	**$2,531,000**	**$178,000**	**$8,423,000**
TOTAL DIRECT COST	**$23,777,000**	**$3,478,000**	**$11,336,000**	**$38,591,000**
HOME OFFICE				$7,164,000
FIELD NON-MANUAL				$2,750,000
TOTAL INDIRECT COST				**$9,914,000**
TOTAL DIRECT & INDIRECT COST				**$48,505,000**
PROCESS CONTINGENCY				**Not Applied**
PROJECT CONTINGENCY (15%)				**$7,276,,000**
TOTAL INSTALLED COST				**$55,781,000**

TABLE 5–5

BIOMASS GASIFICATION RETROFIT PROJECT CAPITAL COST ESTIMATE
NEXT PLANT DESIGN

Basis: January 2000

Item	Material	Labor	Subcontract	Total Cost
PLANT SYSTEMS				
Wood Drying/Gasification	10,443,000	440,000	9,622,000	$20,505,000
Gasification Utilities	250,000	10,000		$260,000
Condensing Steam Turbine	1,678,000		1,280,000	$2,958,000
Wood Handling	2,315,000	350,000		$2,665,000
Electrostatic Precipitator/ash Handling	1,504,000		800,000	$2,304,000
Product Gas	1,615,000		290,000	$1,905,000
Cooling Water	410,000	163,000		$573,000
Switchyard/Electrical	80,000		91,000	$171,000
Distributed Control	270,000		75,000	$345,000
Subtotal	**$18,565,000**	**$963,000**	**$12,158,000**	**$31,686,000**
BULK MATERIALS				
Site Improvements	3,000	65,000		$68,000
Gasification	4,307,000	1,592,000	176,000	$6,075,000
Gasification Utilities	631,000	315,000		$946,000
Condensing Steam Turbine	195,000	189,000		$384,000
Wood Handling	149,000	55,000		$204,000
Ash Handling	119,000	75,000		$194,000
Product Gas	165,000	129,000		$294,000
Cooling Water	517,000	258,000		$775,000
Switchyard/Electrical	68,000	50,000		$118,000
Distributed Control	20,000		20,000	$40,000
Subtotal	**$6,174,000**	**$2,728,000**	**$196,000**	**$9,098,100**
TOTAL DIRECT COST	**$24,739,000**	**$3,691,000**	**$12,354,000**	**$40,784,000**
HOME OFFICE				$7,679,000
FIELD NON-MANUAL				$3,011,000
TOTAL INDIRECT COST				**$10,690,000**
TOTAL DIRECT & INDIRECT COST				**$51,474,000**
PROJECT CONTINGENCY (25%)				**$12,868,000**
PROCESS CONTINGENCY				**$3,550,,000**
TOTAL INSTALLED COST				**$67,892,000**

TABLE 5–6

BIOMASS GASIFICATION RETROFIT PROJECT CAPITAL COST ESTIMATE
NTh PLANT DESIGN GENERIC APPLICATION

Basis: January 2000

Item	Material	Labor	Subcontract	Total Cost
PLANT SYSTEMS				
Gasification/Drying	9,941,000	424,000	8,622,000	$18,987,000
Gasification Utilities	250,000	10,000		$260,000
Wood Handling	3,171,000	480,000		$3,651,000
Ash Handling	1,504,000		800,000	$2,304,000
Product Gas	700,000		150,000	$850,000
Cooling Water	275,000	22,000		$297,000
Distributed Control	295,000		75,000	$370,000
Subtotal	**$16,136,000**	**$936,000**	**$9,647,000**	**$26,719,000**
BULK MATERIALS				
Site Improvements	3,000	15,000		$18,000
Gasification	3,900,000	1,437,000	164,000	$5,501,000
Gasification Utilities	628,000	323,000		$951,000
Wood Handling	186,000	68,000		$254,000
Ash Handling	119,000	75,000		$194,000
Product Gas	19,000	15,000		$34,000
Cooling Water	349,000	188,000		$537,000
Electrical	25,000	25,000		$50,000
Distributed Control	20,000		20,000	$40,000
Subtotal	**$5,249,000**	**$2,146,000**	**184,000**	**$7,579,000**
TOTAL DIRECT COST	**$21,385,000**	**$3,082,000**	**$9,831,000**	**$34,298,000**
HOME OFFICE				$6,672,000
FIELD NON-MANUAL				$2,441,000
TOTAL INDIRECT COST				**$9,113,000**
TOTAL DIRECT & INDIRECT COST				**$43,411,000**
PROCESS CONTINGENCY				**Not Applied**
PROJECT CONTINGENCY (15%)				**$6,512,000**
TOTAL INSTALLED COST				**$49,923,000**

Section 6

Syngas Utilization Considerations

6.0 Syngas Utilization Considerations

Medium Calorific Value Gas (MCVG) consists of methane (CH_4), carbon dioxide (CO_2), carbon monoxide (CO), hydrogen (H_2), and water vapor (H_20), along with small amounts of other light hydrocarbons. It has a volumetric heating value approximately half that of typical natural gas, so is potentially a viable industrial fuel. The purpose of this section of the report is to assess the impacts of MCVG on the performance of lime sludge reburning kilns used in the pulp and paper industry as part of the recausticizing operation. In the discussion below, MCVG will be compared to natural gas and to fuel oil, both of which are currently used as fuel for lime reburning in the industry. These fuels will be compared on the basis of flame temperature and other combustion parameters. The results of this comparison will then be discussed in terms of the impact on lime kiln performance. A practical means of assessing MCVG performance with a simple mill trial using fuel oil was proposed, but was not implemented due to the decision to delay consideration of the project at New Bern.

6.1 Process Impacts Of MCVG

Table 6-1 lists the approximate chemical composition of several fuels including MCVG, along with a calculation of both the theoretical flame temperature and an estimated actual flame temperature for a lime kiln. The composition of natural gas varies considerably across the country and around the world. The natural gas in the table is an average for natural gas for the Southern U.S. The MCVG (Medium-Btu) is the average of several analysis from the Battelle reports of experiments with the LIVG technology. The chemical composition of the fuel oil is not accurate, but the heating value and stoichiometric air requirement are correct.

Table 6–1 has one column each for natural gas and for MCVG. There are four columns for fuel oil for four different levels of excess air. The calculation of the fuel parameters in the table are based solely on the specified chemical composition and are very straightforward stoichiometric calculations.

The fuel parameters include the very common specification of the volumetric heating value for the gaseous fuels. Pipeline natural gas is typically near 1,000 Btu/ft^3. Comparing the heating values shows very dramatic differences between the fuels. However, this common fuel parameter grossly overstates the differences between these fuels. What is often overlooked is the stoichiometric air requirement. It takes both fuel and air to have combustion, so the air requirement is as important as the heating value. The table shows that the air requirement decreases for lower heating value fuels. This is the major reason for the initially surprising result shown for the flame temperatures.

The theoretical flame temperature is a straightforward thermodynamic calculation which accounts for the conversion of all the chemical energy in the fuel into thermal energy in the combustion products. Assumptions are made about the chemical state of the products and about the specific heat of the products, but otherwise the calculation is a strict energy balance. In the table, the combustion products are assumed to be CO_2, H_2O, O_2, and N_2; i.e., disassociation of CO_2 into CO and O_2 is not included (this is a small effect at these temperatures, and a negligible one at the actual flame temperatures). The specific heat is taken for each combustion product as the average for the temperature range from 77°F to 3000°F.

	Natural Gas	Medium-Btu Gas	Fuel oil	Fuel oil	Fuel oil	Fuel oil
Composition						
Methane-CH4	83.3%	12%				
Ethane-C2H6	5.7%					
Propane-C3H8	2.0%					
Butane-C4H10	0.6%					
Fuel oil equivalent-C10H10	0.0%	3%	100%	100%	100%	100%
Carbon monoxide-CO		37%				
Hydrogen-H2		27%				
Nitrogen-N2	7.3%	3%				
Carbon dioxide-CO2	1.0%	11%				
Water vapor-H20		7%				
Temperature, °F	77	77	250	250	250	250
Fuel parameters						
Higher heating value, Btu/cu ft	1,007	446	-	-	-	-
Higher heating value, Btu/lbm	20,384	7,723	19,700	19,700	19,700	19,700
Net heating value, Btu/lbm	18,423	7,128	18,973	18,973	18,973	18,973
Air-to-fuel ratio, lbm/lbm	14.7	5.0	13.2	13.2	13.2	13.2
Flame temperatures						
Excess air	*10%*	*10%*	*10%*	*20%*	*30%*	*40%*
Adiabatic flame temperature, °F	3,510	3,619	4,249	3,922	3,643	3,401
Typical flame temperature, °F	2,873	2,914	3,117	3,019	2,923	2,829

Table 6-1: Process Impacts of MCVG

Careful examination of Table 6–1 shows that the theoretical flame temperature changes, but the effect is much less dramatic than the heating value would indicate. This is even more true for the estimated actual flame temperature. Here the actual flame temperature calculation takes into account the radiation heat loss from the flame. The conditions used for the calculation are typical of a lime reburning application. The heat input to the kiln was taken as 80 MM Btu/hr, and the flame was assumed to be 4 feet in diameter and 25 feet long with an emissivity of 0.3 for the gaseous fuels and 0.9 for fuel oil, radiating to the surrounding lime and refractory at 2000°F. The calculated temperatures are much more realistic estimates of the actual flame temperature in a kiln than the theoretical flame temperature. The differences in this temperature for the various fuels is quite small. This is because the heat in the fuel is absorbed by the combustion products, which consist of the sum of the fuel and the air. A lower air requirement compensates for a lower heating value.

The estimated flame temperature comparison shows several important results. First, the flame temperature for a fuel oil flame at 30% excess air is almost identical to the flame temperature for the MCVG at 10% excess air. This means that a practical trial could be carried out in the mill of the impact of MCVG on the kiln by comparing the kiln operation on fuel oil at 10% excess air (about 1.5% O_2) to that at 30% excess air (about 4% O_2). The latter condition would be nearly identical to using MCVG at 10% excess air.

The impact of firing MCVG on kiln efficiency will be very modest. A fairly accurate estimate of kiln efficiency can be made from data gathered under normal kiln operation. The required data includes an estimate of production rate based both on mud feed to the kiln and lime required for recausticizing, a kiln shell temperature profile, and operating data such as gas temperature and oxygen concentration in the kiln exit gas, dust loss, etc.

The impact of firing MCVG on the kiln emissions should be modest. The two main emissions from lime reburning kilns are TRS (total reduced sulfur) and particulate. MCVG combustion characteristics will be very similar to those for natural gas and fuel oil. Complete combustion of fuel and incineration of NCG (non-condensable gases) depends primarily on having sufficient oxygen and good gas mixing in the kiln. At the same flue gas O_2 level, natural gas, fuel oil and MCVG should produce the same destruction efficiency for NCG, with a resulting equivalent flue gas TRS level. Combustion conditions for these fuels will not impact TRS from Na_2S in the lime mud to any significant degree. The quantity of particulate loss from the stack depends on both the dust loss from the kiln and the scrubber efficiency. The impact of MCVG can be assessed using the trial with fuel oil at two different excess air levels.

Section 7

Power Boiler Relifing as a Conventional Alternative

7.0 Power Boiler Relifing as a Conventional Alternative

7.1 Background

The previous two sections dealt with the integration of a gasification system into the New Bern mill and the use of the synthesis gas produced. The present section considers a relifing of the existing No. 1 power boiler to burn wood residuals as the preferred conventional technology alternative for the mill.

In 1991, CRS Sirrine Engineers Inc. developed a design for refurbishing the No.1 power boiler at New Bern. The boiler was originally installed in 1967; and its condition had deteriorated, impacting its reliability. The boiler was still firing hog fuel at that time, but the sand scrubber that Weyerhaeuser had installed to reduce particulate emissions was not operating satisfactorily. Sirrine's scope included replacing the sand scrubber with an electrostatic precipitator to meet emission requirements and making other upgrades necessary to allow the unit to provide good performance for another 15 years. Sirrine prepared a detailed design in order to meet Weyerhaeuser's requirement for a Class 10 (±10%) cost estimate. The Sirrine design was not implemented. Weyerhaeuser and Jacobs-Sirrine updated the design and estimate in 1994. Rather than upgrade the No. 1 power boiler, Weyerhaeuser decided to eliminate burning hog fuel and reduce its service requirements by adding a smaller oil-fired boiler.

For the present evaluation, Stone & Webster utilized the detailed design information from Sirrine and added the necessary design for reactivating the hog fuel handling and feed system and installing the condensing steam turbine with its associated utility/balance of plant systems.

7.2 Design Basis

The No. 1 power boiler was designed to produce up to 388,000 lb/h of 850 psig/825°F steam when firing oil and up to 350,000 lb/hour of steam when firing 30 ton/h of hog fuel (50% moisture) and 1,568 gallons/hour of oil. Since the mill has installed the No. 2 power boiler, the No. 1 power boiler loading has been significantly reduced. Consequently, the relifing project is based on a maximum steam generation capability of 300,000 lb/h with either oil only or oil/wood firing.

The expected performance of the relifed boiler is detailed in Table 7–1.

	OIL ONLY	HOG FUEL + OIL	HOG FUEL ONLY
MAX. STEAM GENERATION , lb/h	350,000	300,000	171,300
Boiler Efficiency, %	86.127	76.92	71.47
Oil Heat Input (HHV Basis), MMBtu/h	457.8	169	NA
Hog Fuel Heat Input (HHV Basis), MMBtu/h	NA	270	270
Oil Feed Rate, lb/h	24,746	9,135	NA
Oil Feed Rate, gpm	51.2	18.9	NA
Hog Fuel Feed Rate, lb/h	NA	60,000	60,000

Table 7–1: Relifed Boiler Expected Performance

At 300,000 lb/h steam production, the total heat input to the boiler is 439.35 MMBtu/hour. The 30 tph of hog fuel contributes 270 MMBtu/h and 1,116 gallons/h of No. 6 fuel oil provides the remaining 169.35 MMBtu/h of heat input.

Performance at reduced loads are predicted to be:

	LOAD, kpph		
	50	150	300
FUEL	Boiler Efficiency, %		
Oil	85.29	86.37	87.46
Wood	69.02	73.33	N.A.
Wood & Oil	75.03	75.57	76.92
	Performance		
Excess Air, %	100	50	15
Steam Temp., °F	700	825	825
Exit Gas Temp., °F	270	300	320
Unburned Combustibles Heat Loss, %	Oil – 0% Wood – 2%	Oil – 0% Wood – 1.76%	Oil – 0%

Table 7–2: Performance at Reduced Loads

The flue gas flow at full load when firing hog fuel and oil is calculated to be 160,290 cfm at 350°F and 5 inches H_2O Gauge.

The scope of the required boiler modifications is:

- Replace air heater
- Replace economizer
- Add single stage mechanical collector
- Add electrostatic precipitator

- Add overfire air system (including fan)
- Replace ID fan and add variable speed drive
- New ducting as needed for above systems
- New fuel spreaders (existing width, no pressure part modifications)
- Repair superheaters
- Install new live-bottom (variable-speed metering screws) in hog fuel metering bin
- Install new bottom ash hopper and bottom ash removal system
- Add ash handling systems for both bottom- and fly-ash
- Use existing structural elements of hog fuel delivery system (from storage pile to boiler fuel metering bin), replace all mechanical components

The electrostatic precipitator is designed for a flue gas flow of 200,000 acfm and an inlet maximum particulate loading of 3 grains per acf. The outlet particulate loading is 0.1 grains per dry scf at 12% CO_2 which is equivalent to 99.7% particulate removal. This level of control is considered "Best Available Control Technology".

The mill plot plan showing the location of the modifications resulting from this project is shown in Figure 7–1 (07194-EM-2A-1).

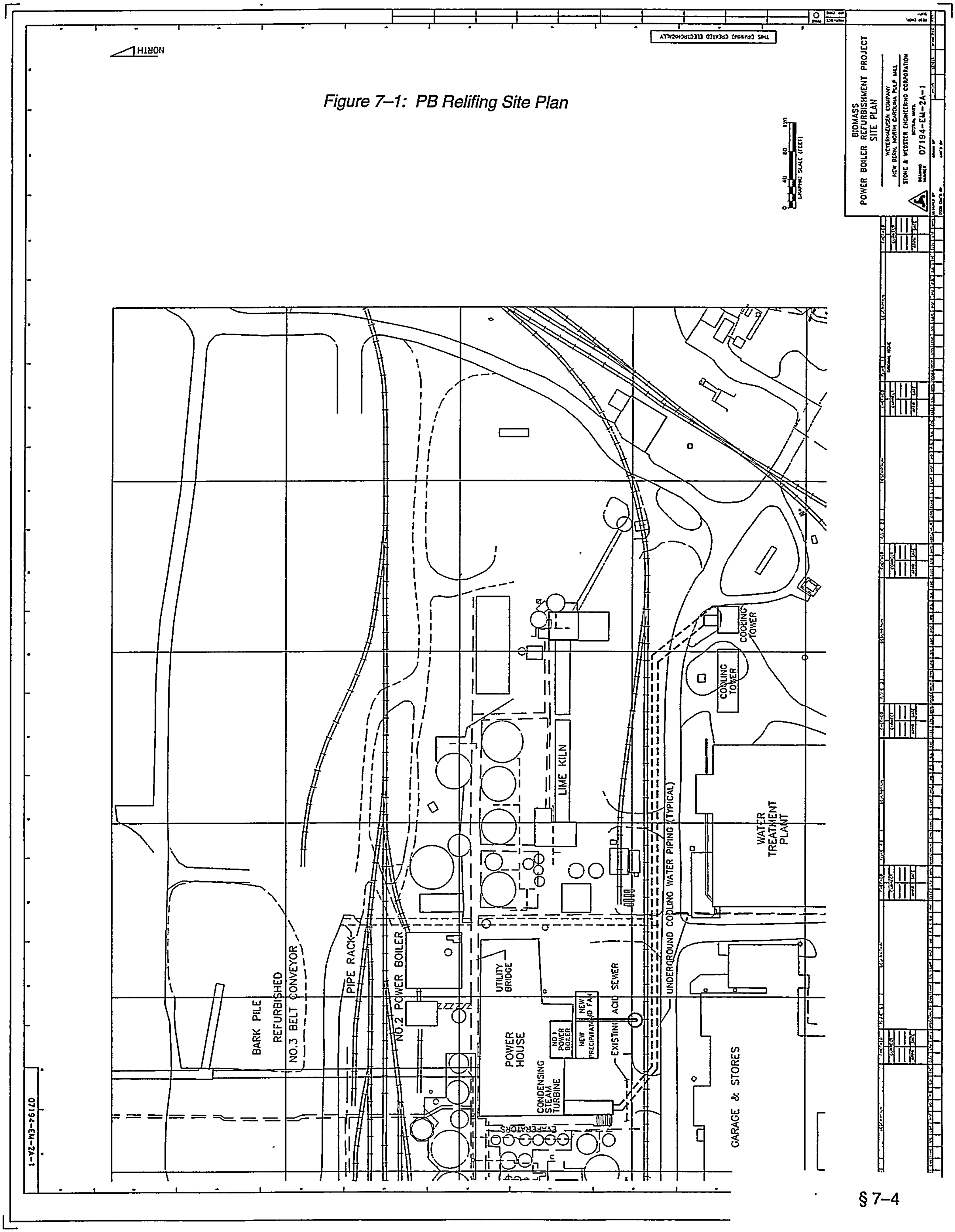


Figure 7–1: PB Relifing Site Plan

7.3 System Descriptions

7.3.1 *Boiler/Flue Gas System Modifications*

The boiler and flue gas system modifications are shown in Figure 7–2 (PFD-PB-001).

The hog fuel is fed to the stoker grate using new fuel spreaders (PBS-FDR1A, B, C, D). A new overfire air fan (PAS-FN1) takes heated primary air from the air heater outlet duct and distributes the air to the overfire air ports. The current standard arrangement for overfire air systems on biomass units is to have large quantities of hot overfire air injected into the furnace through nozzle openings located at various elevations across the front and rear walls. The air admitted through these nozzles is generally 40-50% of the total air flow requirements.

Flue gas leaves the boiler through a new economizer (PBS-ECON1) and enters the new multiple cyclone type dust collector (FGS-DC1). The dust collector particulate removal efficiency is 80%. The 6 dust collector hoppers discharge into 3 new sand classifiers (FGS-SEP1A,B,C). The sand classifiers recover any char particles for reinjection to the boiler. The overfire air fan is used to provide transport air to reinject the unburned material.

The flue gas then flows through a rebuilt tubular air heater (FGS-AH1). The rebuild includes new tubes and erosion shields.

The flue gas leaving the air heater enters a new induced draft fan (FGS-FN1). The fan moves the flue gas through the electrostatic precipitator (FGS-ESP1) and back to the existing roof-top stack.

Combustion air is supplied by the existing forced draft fan and passes through a replaced steam coil air preheater (PAS-AH1) prior to increasing the cold end temperature of the rebuilt tubular air heater.

7.3.1.1 Equipment List

Fuel Spreaders (PBS-FDR1A,B,C,D) – Modulating air swept feeder–30-40 inches water gauge air pressure; includes feed chute–7.5 tons/chute capacity with anti-flash back balance air dampers and boiler front plate.

Economizer (PBS-ECON1) – 8,400 ft^2 of heating surface; 14 ft high x 12 ft 6 inches wide x 17 ft 6 inches long; with sootblowers; estimated wt. 80,000 lbs; inlet water temperature = 312°f; outlet water temperature = 378°f; inlet flue gas temperature = 725°f; outlet flue gas temperature = 647°f, includes lagging and insulation, duct modifications, external piping connections, a relief valve and structural modifications as required.

Overfire Air Fan (PAS-FN1) – 175,000 acfm @ 500°F, 10 inches water gauge with 350 hp motor.

Dust Collector (FGS-DC1) – Multiclone arrangement with a primary dust collector of 360 cyclones, 9 inch diameter each; 3 hoppers wide by 2 deep; includes insulation, lagging, and outlet flanges.

Sand Classifiers (FGS-SEP1A,B,C) – Vibrating screen type sand classifiers; includes char reinjection system.

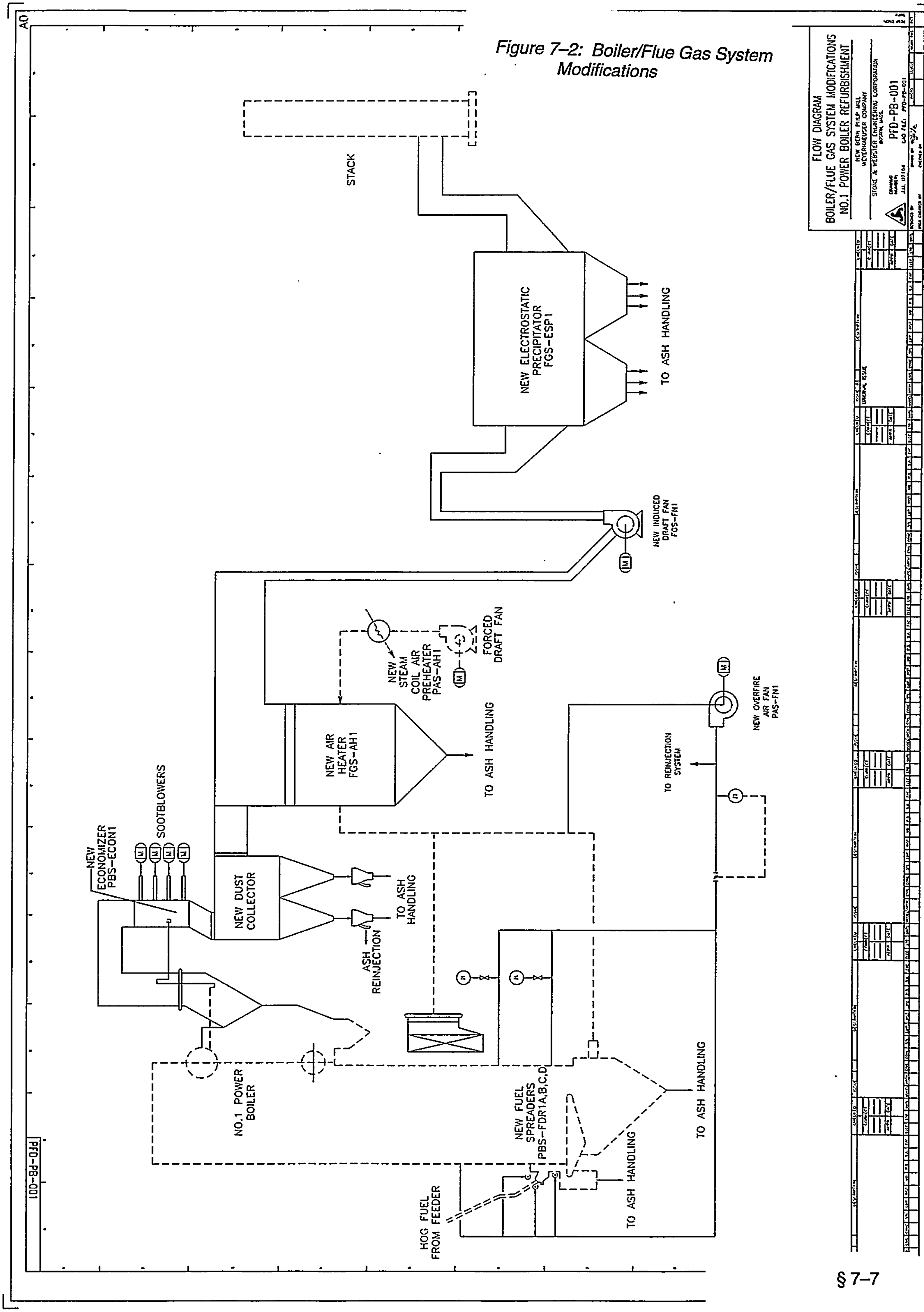
Tubular Air Heater (FGS-AH1) – Duty = 38.5 MMBtu/h; air inlet temperature = 80°f, air outlet temperature = 496°f; flue gas inlet temperature = 647°F; flue gas outlet temperature = 360°F.

Steam Coil Air Preheater (PAS-AH1) – Design air flow 386,000 lbs/hr wet air; Duty = 4.25 MMBtu/h.

Induced Draft Fan (FGS-FN1) – 200,000 acfm, 350°F, 22.5 inches water gauge maximum static pressure; 1000 HP motor with variable speed drive. This motor replaces the steam turbine drive used on the existing induced draft fan.

Electrostatic Precipitator (FGS-ESP1) – 200,000 acfm at 350°F and 5 inches water gauge; design pressure 25 inches water gauge; 3 grains per acf inlet loading; 99.7% collection efficiency; 4 fields; 2 trough type hoppers; 30 ft 6 in wide x 63 ft 11 in long including diffusers x 53 ft 10 in high; includes stand-alone control console with a serial link to the mill DCS.

Figure 7–2: Boiler/Flue Gas System Modifications



7.3.2 *Condensing Steam Turbine System*

The condensing steam turbine system is shown in Figure 7–3 (PFD-001).

The condensing steam turbine system includes the turbine generator, its control and auxiliary systems, main steam piping from high pressure steam header to the turbine throttle, extraction piping to mill medium pressure and low pressure steam headers, a surface condenser, a condenser air removal system, condensate pumps and condensate piping to existing mill deaerator.

The turbine generator (CST-T1) is a nominal 15 MW machine. Steam is admitted to the throttle at 850 psig/825°F. Steam can be extracted from two stages of the turbine, if desired, to supply the mill's medium pressure (155 psig) and/or low pressure (55 psig) steam headers. The turbine full load exhaust flow with no extractions and a condensing pressure of 3 inches Hg is 140,000 lb/hour. The extractions are uncontrolled to minimize the turbine cost. Since external controls are employed for the extraction flow and pressure, an exhaust temperature control system is used to ensure that the flow to the exhaust is sufficient to prevent overheating.

The steam exiting the turbine is condensed in a surface condenser (CST-CND1) and the condensate is pumped using one of two 100% capacity pumps (CST-P1A/B) to the existing mill deaerator. The condenser design duty is 132.5 MMBtu/hour. The design cooling water flow rate is 8,823 gpm based on a 30° ΔT.

Each condensate pump is sized for a maximum flow of 280 gpm. Since the condensing steam turbine will normally be operating at partial load, the condensate pump discharge will be recycled to the condenser hotwell as required to maintain a minimum hotwell level.

Steam ejectors are used for condenser air removal. The system employs a hogging ejector for start up and a holding ejector for normal operation.

7.3.2.1 Equipment List

Turbine generator (CST-T1) – 15 MW nominal size, with two uncontrolled extractions at 155 psig and 55 psig, exhausting at 3 inches Hg; 13.8 kV totally enclosed water to air-cooled generator.

Surface Condenser (CST-CND1) – Heat transfer surface = 18,319 ft^2; 5/8" BWG 304 stainless steel tubes; single pressure, 2-pass.

Condensate Pumps (CST-P1A/B) – 280 gpm horizontal centrifugal pump.

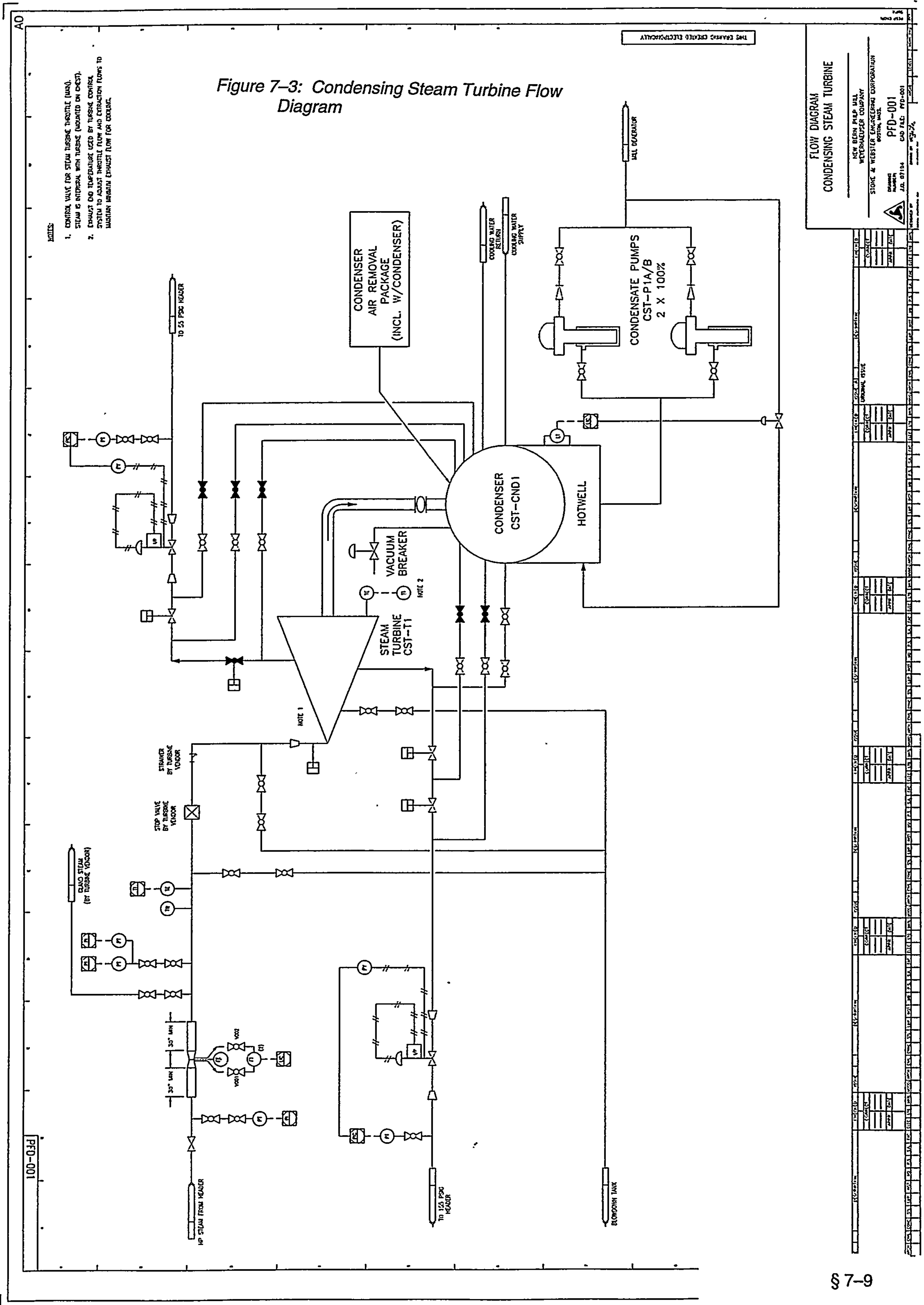


Figure 7–3: Condensing Steam Turbine Flow Diagram

7.3.3 Wood Handling System

The wood handling system is shown on process flow diagram Figure 7–4 (PFD-PB-002).

The system is designed to provide up to 30 tons/hour of hog fuel (bark, rejects, sawdust and associated material) to the No. 1 power boiler. Approximately 30 tons/hour of bark, rejects, sawdust, and associated material produced in the existing mill complex are consolidated in the existing hog fuel processing equipment. The No. 1 belt conveyor transports the hog fuel to a transfer station where it is either discharged to the No. 3 belt conveyor for transport to the No. 1 power boiler hog fuel surge bin or discharged to the No. 2 belt stacking conveyor which feeds the hog fuel storage pile.

Material is reclaimed from the storage pile by a chain reclaim conveyor. The reclaim conveyor feeds the hog fuel onto the No. 3 belt conveyor.

All of the equipment already exists. However, the storage pile reclaim conveyor and the No. 3 belt conveyor have been idle since the early 1990s when the mill stopped burning hog fuel in the No. 1 power boiler. These conveyors will be replaced. A new chain reclaim conveyor will be installed in the reclaim pit. The structural components of the No. 3 belt conveyor are sound. These will be reused and a new 30 inch belt and mechanical components (e.g., idlers, pulleys, drive), motor, controls, magnet and belt scale will be provided.

The hog fuel surge bin is equipped with spiked rollers to feed the fuel to the boiler fuel spreaders. These spiked rollers will be removed. A volumetric feeder (WHS-FDR1) comprised of 12 screws and 4 motors with adjustable speed control will be added to the bottom of the fuel surge bin to improve fuel feeding.

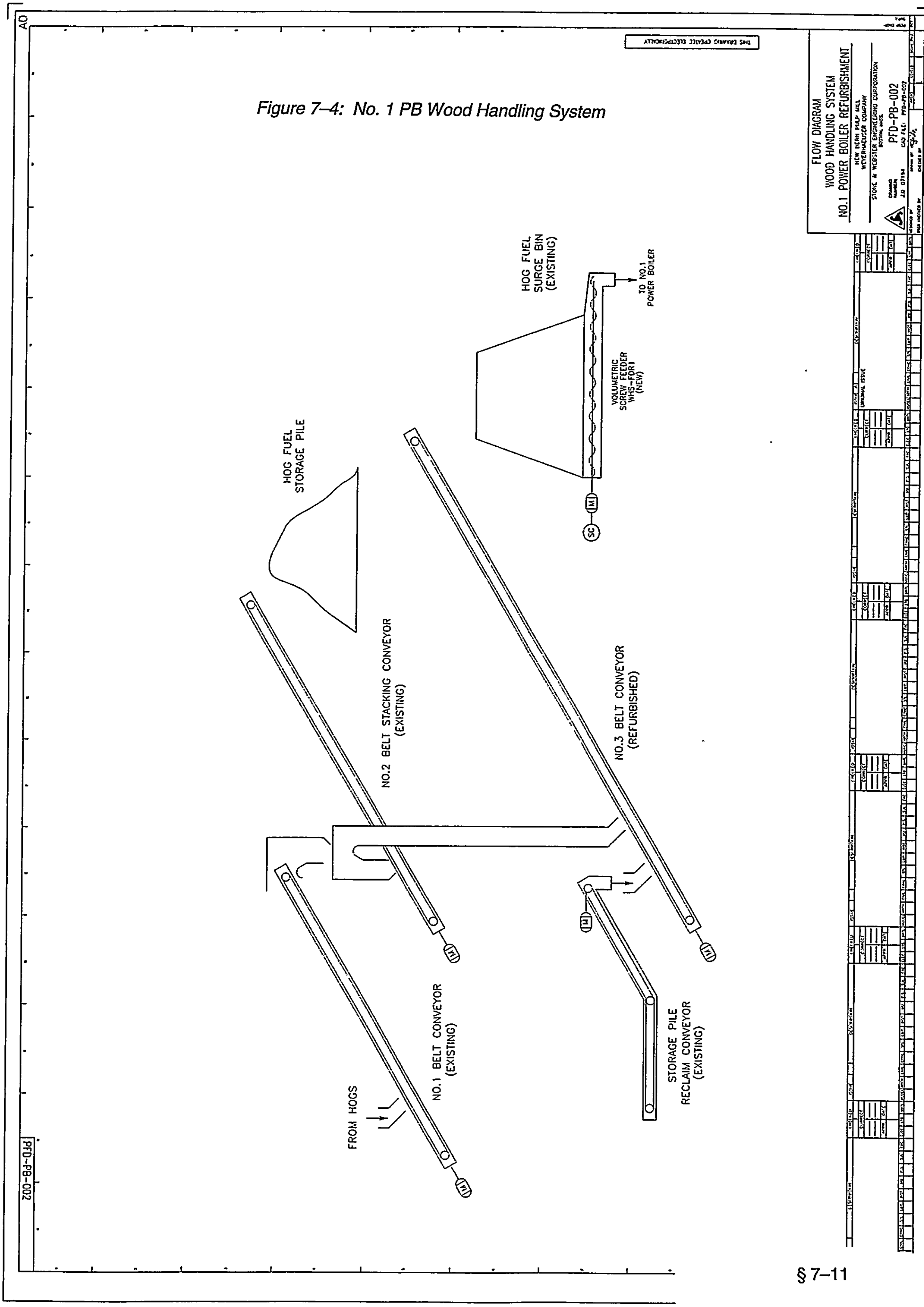
7.3.3.1 Equipment List

Refurbished No. 3 Belt Conveyor – 30 inch wide belt conveyor, rated for 30 tph. Conveyor is 502.28 ft long and is inclined 11°-01'-42"; final elevation is 99 feet-3 inches above grade; includes belt, mechanical components, motor, controls, magnet and scale.

Storage Pile Reclaim Conveyor – Chain conveyor, rated for 30 tph; three 12 inch strands; 53 feet long; inclined 17.8°.

Volumetric Screw Feeder (WHS-FDR1) – 30 tph, carbon steel, 12–14 inch diameter, 14 foot long screws; 4 drives (1 per 3 screws), each comprised of a 5 HP motor, 3:1 constant torque controller, gear reducer and chain drive.

Figure 7–4: No. 1 PB Wood Handling System



7.3.4 *Ash Handling System*

The ash handling system is shown in Figure 7–5 (PFD-PB-003).

The ash produced from burning hog fuel in the No. 1 power boiler is comprised of stoker siftings, bottom ash and flyash collected in the dust collector, air heater and precipitator. This ash must be removed and disposed of.

Bottom ash falls off the end of the stoker grate into a refractory-lined hopper (AHS-HOP1) which directs the ash into a wet (submerged) drag chain conveyor (AHS-CNV5). Water is added to this conveyor to maintain a constant level, compensating for water absorbed by the ash and lost to evaporation. Siftings, material that either falls through the grate or drops off the grate as it returns to hog fuel feed end, are collected in a hopper under the stoker grate. This hopper discharges to the siftings conveyor, AHS-CNV4. The siftings conveyor is a dry drag chain conveyor that transfers the siftings to AHS-CNV5. The siftings and bottom ash are transported by AHS-CNV5 to the ash transfer conveyor No. 1 (AHS-CNV6), a dry drag chain conveyor.

Flyash removed by the new mechanical dust collector falls by gravity from three hoppers into double flap airlock valves (AHS-LK1A, B, C). These valves deposit the ash onto the sand classifier conveyor (AHS-CNV1), a dry drag chain conveyor. This conveyor brings this ash to AHS-CNV6 where it joins the bottom ash and siftings.

AHS-CNV6 discharges to the ash transfer conveyor No. 2 (AHS-CNV7), a dry, drag chain conveyor.

Ash which accumulates in the hoppers of the new air heater falls by gravity into double flap airlock valves (AHS-LK2A, B). These valves deposit the ash onto the air heater conveyor (AHS-CNV2), a dry drag chain conveyor. This conveyor discharges the air heater ash to AHS-CNV7 where it joins the siftings, bottom ash and dust collector ash.

The ash removed in the new electrostatic precipitator collects in two trough hoppers and falls by gravity into two ash collecting conveyors (AHS-CNV3A, B). These dry drag chain conveyors each discharges into a double flap airlock valve (AHS-LK3A, B). The airlocks direct the ash onto AHS-CNV7 where it joins the rest of the ash. AHS-CNV7 transfers all the ash to the storage silo.

The ash storage silo (AHS-SILO1) is sized for 24 hours of maximum ash production, assuming a minimum ash density of 20 lb/ft^3. The silo is designed to allow a truck to drive under the discharge hopper. The discharge hopper is equipped with an ash conditioning unit (AHS-W1) that wets the ash to increase its density for disposal.

7.3.4.1 Equipment List

Bottom Ash Hopper – Castable refractory-lined hopper; 14 feet long x 10 feet high x 2 feet wide

Sand Classifier Collector Conveyor (AHS-CNV1) – Design capacity = 4,500 lb/h; 6x18 single strand drag chain with 33 feet horizontal sprocket centers; operates at 10 fpm; 1 HP motor

Air Heater Conveyor (AHS-CNV2) – Design capacity = 1,500 lb/h; 2x12 single strand drag chain with 29 feet horizontal sprocket centers; operates at 10 fpm; 1 HP motor

Precipitator Collecting Conveyors (AHS-CNV3A,B) – Design capacity = 0.5 tph; 2x12 single strand drag chain with 37 feet horizontal sprocket centers; operates at 10 fpm; 1 HP motor

Siftings Conveyor (AHS-CNV4) – Design capacity = 500 lb/h; 2x12 single strand drag chain with 17 feet horizontal sprocket centers; operates at 10 fpm; 1 HP motor

Bottom Ash Submerged Conveyor (AHS-CNV5) – Design capacity = 0.5 tph; 2 feet wide with 36 feet horizontal sprocket centers; operates at 10 fpm; 2 HP motor

Ash Transfer Conveyor No. 1 (AHS-CNV6) – Design capacity = 5,000 lb/h; 2 feet-6 inches wide double strand design with 75 feet true sprocket centers; operates at 10 fpm up a 40° incline to discharge into top of ash silo; 3 HP motor

Ash Transfer Conveyor No. 2 (AHS-CNV7) – Design capacity = 3 tph; 2 feet-6 inches wide double strand design with 112 feet true sprocket centers; operates at 10 fpm up a 40° incline; 2 HP motor

Double Flap Airlock (AHS-LK1A,B,C) – Design capacity = 1,500 lb/h; design pressure = 5 inches H_2O

Double Flap Airlock (AHS-LK2A,B) – Design capacity = 750 lb/h; design pressure = 5 inches H_2O

Double Flap Airlock (AHS-LK3A,B) – Design capacity = 1,000 lb/h; design pressure = 5 inches H_2O

Ash Silo (AHS-SILO1 – Steel silo 20 feet diameter, 37 feet height with 60° bottom cone; bottom outlet 20’ above grade

Ash Conditioning Unit (AHS-W1) – Design capacity = 30 tph; maximum ash inlet temperature = 300°F; includes all valves, fittings feeders from silo bottom outlet through truck loading outlet

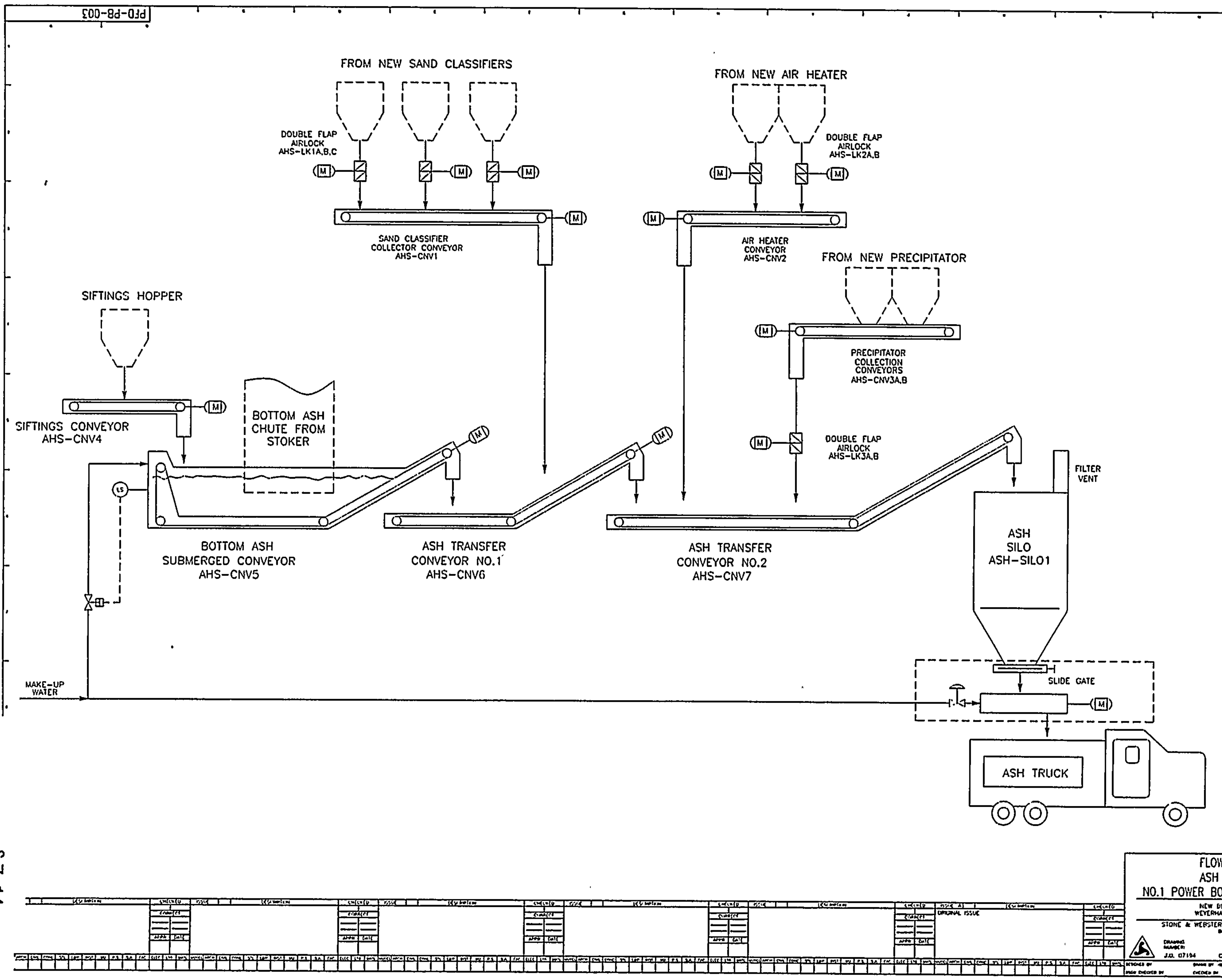


Figure 7-5: No. 1 PB Ash Handling Flow Diagram

7.3.5 Cooling Water System

The cooling water system is shown in Figure 7–6 (PFD-PB-005). The system is designed to meet the following cooling requirements:

- Condensing steam turbine condenser 8,823 gpm @ 30°ΔT
- Condensing steam turbine lube oil cooler 200 gpm @ 20°ΔT
- Condensing steam turbine generator cooler 260 gpm @ 20°ΔT

The total circulating water flow is 9,283 gpm.

The system is a closed cycle utilizing a single cell mechanical draft cooling tower (CWS-TWR1).

Two 50% capacity circulating water pumps (CWS-P1A,B) take suction from the cooling tower basin and distribute the water to the specified users and back to the cooling tower fill.

The cooling tower blowdown rate is established to maintain the required water solids levels. The make up water to the tower is controlled by the water level in the basin.

7.3.5.1 Equipment List

Cooling Tower (CWS-TWR1) – Single cell 48 feet long by 36 feet wide counterflow mechanical draft cooling tower with single speed fan; tower cooling duty = 137 MMBtu/h

Circulating Water Pumps (CWS-P1A,B) – 4700 gpm vertical centrifugal pumps

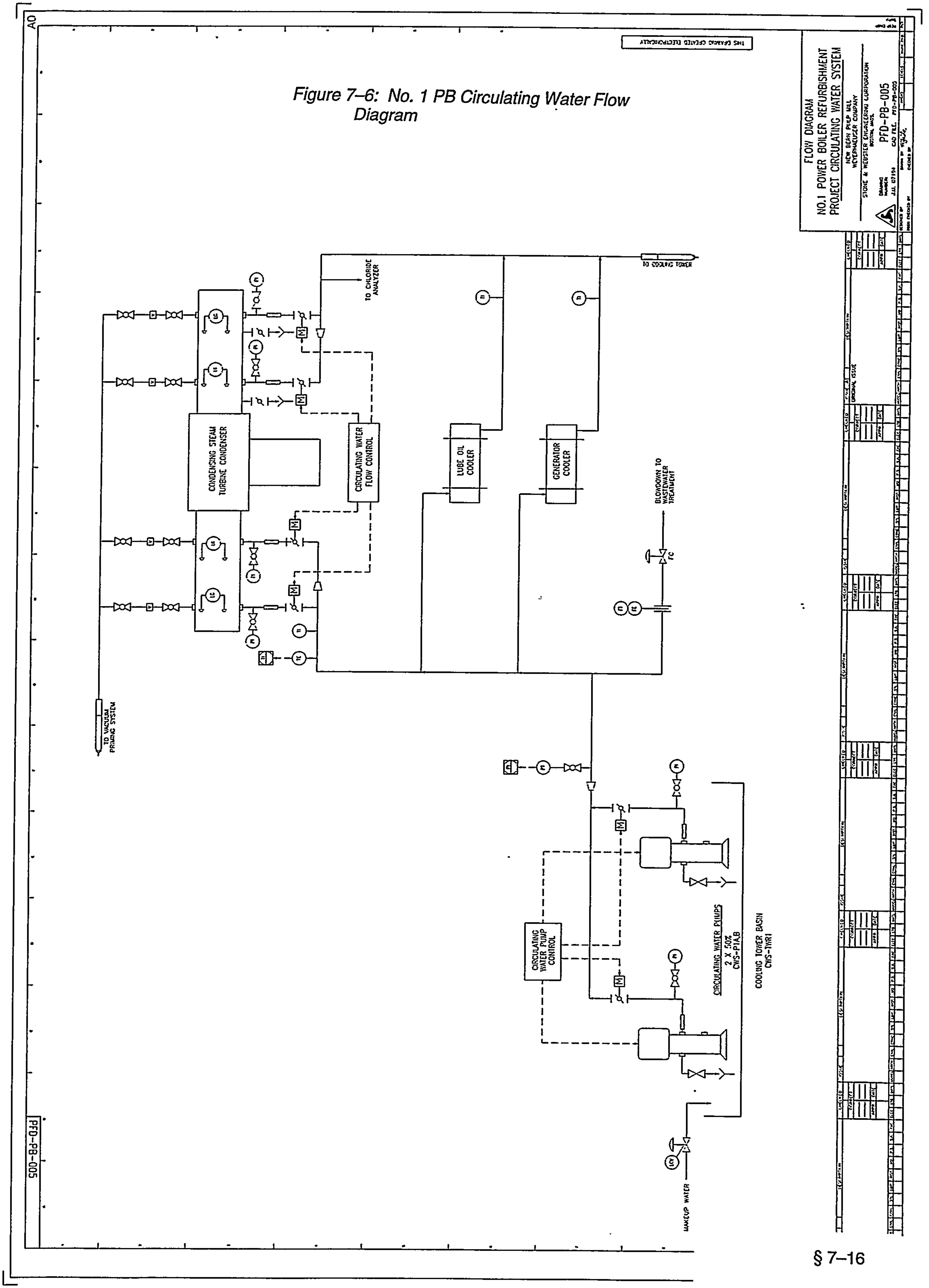


Figure 7–6: No. 1 PB Circulating Water Flow Diagram

7.3.6 *Other Utility/Infrastructure Requirements*

The other project utility and infrastructure requirements include:

- Instrument air
- Electrical interconnections
- Interconnections to mill DCS

The additional electrical loads total about 1.5 MW as follows:

Boiler Relifing Project Additional Electrical Loads	
	kWe
Overfire Air Fan	261
Induced Draft Fan	746
Condensate Pump	18
Ash Handling	9
Wood Handling	100
Circulating Water Pumps	163
Cooling Tower Fan	85
Electrostatic Precipitator	117
Steam Turbine Auxiliaries	19
Misc.	10
TOTAL	1528 kWe

Table 7–3: Additional Electrical Loads

7.4 Capital Cost Estimate

7.4.1 *Estimate Approach*

Stone & Webster prepared the estimate by updating previous estimates for the No. 1 power boiler relifing that had been developed by CRS Sirrine and Jacobs-Sirrine, and adding the costs for reactivation of the hog fuel transfer and feeding system and installation of the condensing steam turbine. Sirrine had prepared a Weyerhaeuser Class 10 estimate in 1991. The Class 10 estimate is intended to have an accuracy of ±10%. To achieve this accuracy requires substantial design work. Sirrine produced major equipment specifications, arrangement drawings, piping & instrumentation drawings, one-line diagram, electrical load list, instrument list and control I/O list. The estimate was generated from major equipment quotations and quantity takeoffs for development of bulk material quantities.

Jacobs-Sirrine updated their estimate in December, 1994. The 1991 estimate included a secondary dust collector and a new stack. The 1994 estimate did not include these items. Sirrine updated the estimate by deleting the items removed from the project scope of work, obtaining new prices for the major equipment and adjusting labor rates and bulk material costs.

The present scope of work for relifing of the No. 1 power boiler includes the following items that were not in the 1994 Jacobs-Sirrine estimate:

- New tubular air heater
- New steam coil air heater
- Superheater repairs
- New fuel spreaders
- Grate repairs
- New bark pile reclaim conveyor
- New conveyor from wood yard to boiler fuel bin

The extent of superheater and grate repairs has not been defined, so an allowance developed from experience was included for these items. Stone & Webster obtained budget prices for the other new items and estimated the associated installation cost. Current budget prices were also obtained for the major equipment previously estimated by Sirrine. The Sirrine labor rates and bulk material prices were adjusted to present day. Stone & Webster estimated the costs for the condensing steam turbine addition which necessitated a new single cell cooling tower.

Based on the estimating approach, this estimate is considered to be between a preliminary cost estimate (Class 20) and a detailed (Class 10) estimate. The estimate accuracy range should be ± 15%.

7.4.2 *Estimating Basis and Assumptions*

The capital cost estimate was developed based on the following assumptions:

- Cost data are based on a January 2000 price level.
- Owners' costs are not included.
- Cost of permits, applications and inspections by governmental bodies not included.
- No clearing & grubbing required.
- No mass earthwork; no allowance for site remediation.
- Excavated material is suitable for structural backfill.
- No subdrains or special drainage provisions; water table is below the lowest level of excavation.
- No storm drains.
- Only paving included is for access to ash storage silo.
- No material will be disposed of off site.
- There is no provision for sales tax.
- All major foundations rest on precast concrete piles with average length of 60 LF.
- Electrical cables are routed in tray supported from pipe/utility bridge (no underground routing).

- The only underground systems are cooling water to/from the main mill pipe bridge to the condensing steam turbine condenser and electrical grounding.
- No allowance for price/wage escalation has been provided. Project duration is expected to be about 18 months.
- Engineering, procurement, and other management/administration costs ("Home Office Cost") have been estimated as a percentage of the constructed cost of the plant. The percentage used is typical for projects in this cost range.

7.4.3 Estimate Components

7.4.3.1 Direct Field Material Costs

Direct field material costs are for permanent physical plant facilities. They include the following elements:

- **Equipment.** Equipment includes all machinery used in the completed facility, such as boilers, rotating machinery, heat exchangers, tanks, and vessels.
- **Material.** Materials include concrete, steel, building materials, pipe and fittings, valves, wire and conduit, instruments, insulation, and paint used in constructing the completed plant.
- **Freight.** Freight to the job site is included.

7.4.3.2 Direct Field Labor Costs

The components of direct field labor costs are labor manhours and the composite labor wage rate.

7.4.3.3 Direct Subcontract Costs

Direct subcontract costs are those for equipment, materials, and services furnished by the subcontractors, including installation labor costs and related indirect field costs.

Major items that were estimated as subcontract costs include:

- Boiler modifications (fuel feed, grate, economizer, superheater, air heater, ash reinjection)
- Condensing steam turbine relifing and reinstallation
- Cooling tower
- Electrostatic precipitator
- Ash handling equipment

7.4.3.4 Indirect Field and Home Office Engineering Costs

Indirect field costs are costs that cannot be directly identified with any construction operation related to specific plant facilities but that support the general construction operation.

These costs for indirect labor and materials include allowances for the following items:

- Miscellaneous construction services (labor) covering cleanup, maintenance of tools and construction equipment, security, surveying and testing.
- Temporary construction
- Materials including temporary buildings and roads, utilities and services, scaffolding, testing, construction equipment, tools and consumables.
- Construction non-manual personnel

Home office engineering manhours and other home office services cover the expenses of the following items:

- Labor for engineering design, procurement, technical services, administrative support, and project management services
- Office expenses such as materials, telephone, reproduction and computer costs, and travel

7.4.3.5 Contingency

A project contingency of 12.5% is applied. Weyerhaeuser's Standardized Project Process utilizes an 8 to 10% contingency. However, based on the size of this project, the contingency was increased.

7.5 Boiler Relifing Project Cost Estimate

The capital cost for the boiler relifing project is $22.7 million as shown in Table 7-4.

7.6 Operating & Maintenance Costs

7.6.1 Staffing Requirements

Additional Control Room Operators	1 per shift	= 4
Wood yard	1 per shift	= 4
Roving Operators	0.5 per shift	= 2
	TOTAL	**10**

TABLE 7-4

NO. 1 POWER BOILER RELIFING PROJECT
CAPITAL COST ESTIMATE

Basis: January 2000

Item	Material	Labor	Subcontract	Total Cost
PLANT SYSTEMS				
Boiler Relifing				
Site Modifications	6,000	175,000	31,000	$212,000
Buildings	73,000	109,000	3,000	$185,000
Conveyor Repairs	185,000	30,000		$215,000
Electrostatic Precipitator	1,320,000		620,000	$1,940,000
Ash Handling	910,000	104,000		$1,014,000
Boiler Modifications	1,789,000	886,000	3,048,000	$5,723,000
Foundations	285,000	465,000	167,000	$917,000
Piping	70,000	206,000	74,000	$350,000
Electrical & Instrumentation	1,310,000	576,000		$1,886,000
Building Services	151,000	198,000	3,000	$352,000
Condensing Steam Turbine				
Buildings	66,000	4,000	40,000	$110,000
Equipment	1,556,000		1,222,000	$2,778,000
Foundations	75,000	125,000		$200,000
Piping	90,000	40,000		$130,000
Electrical & Instrumentation	40,000	15,000		$55,000
Building Services	16,000	5,000		$21,000
Cooling Water				
Site Modifications	2,000	4,000		$6,000
Equipment	81,000	27,000	219,000	$327,000
Foundations	23,000	63,000		$86,000
Piping	290,000	130,000		$420,000
Electrical & Instrumentation	43,000	22,000		$65,000
TOTAL DIRECT COST	**$8,381,000**	**$3,184,000**	**$5,427,000**	**$16,992,000**
HOME OFFICE				$2,025,000
FIELD NON-MANUAL				$1,125,000
TOTAL INDIRECT COST				**$3,150,000**
TOTAL DIRECTS + INDIRECTS				$20,142,000
PROJECT CONTINGENCY (12.5%)				**$2,518,000**
TOTAL INSTALLED COST				**$22,660,000**

Section 8

Economics of New Bern Alternatives

8.0 Economics of New Bern Alternatives

8.1 Approach

Economic viability of the FERCO-LIVG (Low Inlet Velocity Gasification) technology at the New Bern mill is assessed using standard incremental economic evaluation techniques. The analysis is done in nominal-dollar terms. The costs and benefits of the Gasification Project described in Section 5 are assessed based on thermodynamic performance, operating requirements of the defined project, New Bern site energy demands and in the context of current and future projections of relevant unit cost parameters.

This assessment will focus on economic viability of the LIVG process configured to meet the thermal and electrical requirements of the New Bern site. Given that emerging technologies such as LIVG process must offer benefits beyond what is currently available to warrant consideration by potential users, LIVG process economics will be compared to an analogous conventional technology alternative. The No. 1 Power Boiler Relifing Project, described in Section 7, is defined and evaluated as the conventional technology alternative for minimizing fossil fuel dependence at New Bern. Like the gasification case, this option attempts to make maximum utilization of existing on-site equipment by modifying the No. 1 power boiler to facilitate biomass fuel utilization. Unlike the gasification case, this alternative does not allow biomass utilization by multiple fuel users—the mill lime kiln and No. 2 power boilers continue to be fired by fossil fuel. Economics of the two process options will be compared for the default set of economic assumptions. Sensitivity analysis and the impact of potential public policy incentives to encourage broader use of biomass fuels will focus on the LIVG process option.

Both biomass options are compared to a base case which defines current and projected future operating costs and minimum capital requirements for continued reliable steam generation for the site. The base case presumes that the status quo will continue with #6 fuel oil as the primary non-recovery fuel used at New Bern. A maintenance capital investment of $1.8 million is included in the base case in order to relife the No. 1 power boiler to a level of reliability and longevity that is consistent with the No. 1 Power Boiler Relifing Project. Likewise, $1.8 million in additional capital expenditure is also added to the Gasification Project alternative for the same reason. This maintenance capital figure was derived from capital cost estimate for the No. 1 Power Boiler Relifing Project and is part of that project's scope. Maintenance capital costs include superheater repairs and replacement of both the air heater and economizer

The New Bern-specific analysis will take a "Next Plant" perspective as the New Bern project has been proposed as an early demonstration of the LIVG technology. "Nth Plant" economic potential of the LIVG technology will be discussed in a subsequent section of this report.

8.2 Overview of Alternatives

Table 8–1 below summarizes the major impacts of the two alternative biomass projects on the fuel and purchased power requirements of the New Bern mill. Default capital cost values for the alternatives are also included. Mill steam requirements were estimated based on historical process data and future production plans. The hourly average fuel requirements shown below are based on a month-by-month annual assessment that takes into account seasonally-induced variation in mill thermal requirements as well as the operational constraints of the mill's two power boilers. These constraints include such items as boiler turndown limits, minimum support fuel requirements for non-condensable gas destruction, and keeping boilers in a suitable load range for response to modulating steam needs of the facility.

Parameter	Base Case: Oil as Non-Recovery Fuel	No. 1 P/B Biomass Retrofit w/CST	Biomass Gasifier with CST
Capital Cost	$1.8 million	$22.7 million	$69.7 million (Next Plant) $57.6 million (Nth plant)
Oil Use for Steam Generation	45.4 Bbl/hr	22.7 Bbl/hr	8.7 Bbl/hr
Lime Kiln Fuel	15.8 Bbl/hr	15.8 Bbl/hr	Biomass gas
Disposition of Site Fuel Residuals	Sell 187,000 GT/yr	To No. 1 P/B	To Biomass Gasifier
Purchased Biomass Fuel	None	52,500 GT/yr to No. 1 P/B	371,000 GT/yr to Biomass Gasifier
Added Electrical Connected Load	N/A	1.5 MW	5.4 MW
Purchased Electric Power	6.0 MW	Self-Sufficient	Self-Sufficient

Table 8–1: Overview of Project Alternatives

The figures in Table 8–1 are based on annual biomass and fossil fuel requirements and thus, represent "mid-season" conditions while the New Bern mill is running at its target production rate. As is seen in the table, the gasifier alternative does not completely eliminate fossil fuel use at the site. The system has been sized to ensure high gasifier system capacity utilization on a year-around basis. During summer months, the gasifier system is turned down slightly, due to the lower seasonal thermal loads. During winter months, non-recovery thermal loads exceed gasifier capability necessitating that some fuel oil still be used.

8.3 Analytical Method, Assumptions and Key Inputs

As stated above, alternatives were evaluated using incremental economic evaluation methods. The net benefits of each alternative are reduced to an after-tax cash flow stream. Escalation factors are applied to the various operating costs to account for the impacts of inflation. Capital expenditures are considered as pure equity investments; there are no leverage impacts due to the effects of debt financing. Net present value and internal rate of return are calculated for each alternative in accord with the following analytical framework:

Life of projects – Twenty five years

Nominal inflation rate – 2.5%/yr.

Combined tax rate – 38% (includes State and Federal)

Discount rate – 12% (for net present value calculations)

Investment tax credits (North Carolina-specific) – 5%, 15% for biomass projects

Depreciation schedules – Fifteen year double-declining balance, five year DDB for biomass projects.

Project residual values – Based on after-tax cash flow in last year of operation

The operating cost/benefit impacts of each biomass alternative are considered in the following cost categories:

Biomass fuel cost/revenue – Manufacturing residuals at the New Bern site are currently sold. In each biomass alternative, all internal residuals are consumed as fuel at the expense of the current sales revenue. Both options require additional purchase of biomass fuels in the local market at prices based on the supply analysis presented in Section 2. Biomass fuel prices are escalated at the nominal rate of inflation (zero percent real price escalation).

Fuel oil – Biomass fuel utilization displaces #6 fuel oil use in the No. 1 and No 2 power boiler and the lime kiln in the gasification alternative. In the boiler retrofit case, #6 fuel oil use is only displaced in No. 1 power boiler. Fuel oil prices have fluctuated significantly over the last two years; this analysis is based on an initial (year 2000) price of $20/barrel. Fuel oil price real escalation is assumed at a default value of 0.1%/yr. This value is based on data presented in the Energy Information Administration (EIA) Annual Energy Outlook 2000 publication for their "Reference Case". The impact of these assumptions on project viability will be investigated through sensitivity analysis.

As seen in Table 4-4 in the LIVG process energy and material balance, the LIVG process does not consume all the dryer exhaust steam. This analysis assumes that a reboiler is installed to generate low pressure steam from this heat source, and that a suitable use can be found for this steam that displaces high pressure steam generation. This thermal credit brings the overall thermal efficiency of the gasification island to 89.4% where thermal efficiency is defined as:

$$\frac{\text{(HHV of product gas + heat export from product gas HRSG + heat export from dryer exhaust)}}{\text{HHV of biomass fuel input to gasifier}}$$

This high level of thermal efficiency is considered to be near the upper bound of what is achievable in applying the LIVG process technology. For this reason, no increase in thermal efficiency will be assumed to occur between "Next Plant" and "Nth Plant" when discussing the economics of generic "Nth Plant" technology applications (see Section 9).

Purchased electric power – In each biomass alternative, additional power is generated via the new condensing steam turbine to displace all purchased load and offset the added auxiliary loads imposed by the project itself. In practice, it is recognized that a power grid connection would be maintained with the potential for electric power flow in either direction between the mill and the electric power grid. The default value assumed for the displaced purchased load is $0.05/kWh with sensitivities run at $0.04 and $0.06/kWh. Although electric power industry deregulation is under discussion in North Carolina, there is not yet a clear basis for regional projection of future electric power price escalation. Real escalation assumptions for the market value of electric power are based on Energy Information Agency national projections as follows[1]:

2001–2005	-0.5%/yr.
2006–2010	-1.0%/yr.
2011–2015	+0.7%/yr.
2016 to end of project	-0.3%/yr.

The above escalation rates assume regulated electricity rates prevail until 2005; competitive market assumptions are used from 2006 through the end of project life.

Operating labor – Labor for the biomass alternatives is added based on the staffing requirements estimated in Section 5.5.1. Fully loaded labor rates of $22/hr. are used and are assumed to escalate at the nominal inflation rate.

Maintenance costs – Expensed maintenance labor and materials are estimated to be 3.5% of initial capital per year escalated at the nominal inflation rate. Maintenance capital is added at 3%/yr. These values are based on pulp and paper industry experience and data.

Boiler Feedwater, Waste Water Treatment, Cooling Water and Miscellaneous Chemicals/Operating Supplies – Allowances are made on a case-specific basis and escalated at the nominal inflation rate.

8.4 Results and Discussion

8.4.1 Results

Results of the economic analysis are shown in the following paired graphics, Figures 8–1 through 8–16. Return on investment (ROI) and net present value (NPV) are displayed as functions of invested capital. When an acceptable ROI "hurdle rate" is specified, the figures allow estimation of how much capital can be spent to capture the economic benefits provided by the project. The economic value of the project can then be estimated from the accompanying NPV graphic. In all figures, the green trend lines represent the use of the "default" assumptions for all parameters (except capital cost).

The following sensitivities are investigated independently:

- Sensitivity to oil initial price and escalation assumptions Figures 8–1 and 8–2.
- Average biomass fuel price (outside purchased fuels): Figures 8–3 and 8–4.

[1] Annual Energy Outlook 2000; Energy Information Agency

- Value of displaced purchased electricity: Figures 8–5 and 8–6.
- Sensitivity to maintenance expense and capital assumptions: Figures 8–7 and 8–8.
- Figures 8–9 and 8–10 compare ROI and NPV vs. capital trends for the LIVG Project and for the No. 1 Power Boiler Relifing Project.
- The potential impact of two public policy-based incentives to encourage expanded use of biomass fuels is also investigated. Figures 8–11 and 8–12 demonstrate how LIVG project ROI and NPV are affected by a $1.00/MBtu biomass fuel gas tax credit.
- Figures 8–13 and 8–14 demonstrate the potential impact of tax credits associated with reduction of atmospheric carbon emissions, assuming that biomass substitution (from renewable sources) for fossil fuels would qualify for such tax credits.
- Figures 8–15 and 8–16 create a favorable scenario for biomass utilization by moving several key economic factors in a direction which makes biomass fuel use more attractive. This scenario benefits the No. 1 Power Boiler Relifing Project as well as the Gasifier alternative.

Table 8–2 summarizes the default assumptions used in this analysis and embodied in Figures 8–1 through 8–16. A discussion and interpretation of these figures follows Figure 8-16.

Parameter	Default Value
General inflation rate, %	2.5%
Discount rate, %	12%
Income tax rate, %	38%
Investment tax credit	15% for biomass projects 5% for other capital projects
Tax depreciation	5 yr. double declining balance for biomass projects 15 yr. double declining balance for other capital projects
Project life	25 years
Residual fuel oil price, $/Bbl.	$20.00
Real escalation rate – residual fuel oil, %	0.1%
Average Power Price, ¢/kWh	5¢
Real escalation rate – purchased electric power	2000–2005: -0.5%/yr. 2006 –2010 -1.0%/yr. 2011–2015 +0.7%/yr. 2016 to end -0.3%/yr.
Average biomass price, $/BDT	$18 (at Gasifier Project volume)
Maintenance capital requirement, % of capital/yr.	3.0%
Maintenance materials and labor, % of capital/yr.	3.5%
Capacity Factors (based on 365 day year)	Mill- 92% Gasifier Project- 88% Boiler Relifing Project- 90%
Start Up Dates	Gasifier Project- 2003 Boiler Relifing Project- 2002
Capital Spending Period	Gasifier Project- Two Years Boiler Relifing Project- One Year

Table 8-2: Summary of Default Economic Assumptions (New Bern Alternatives Case)

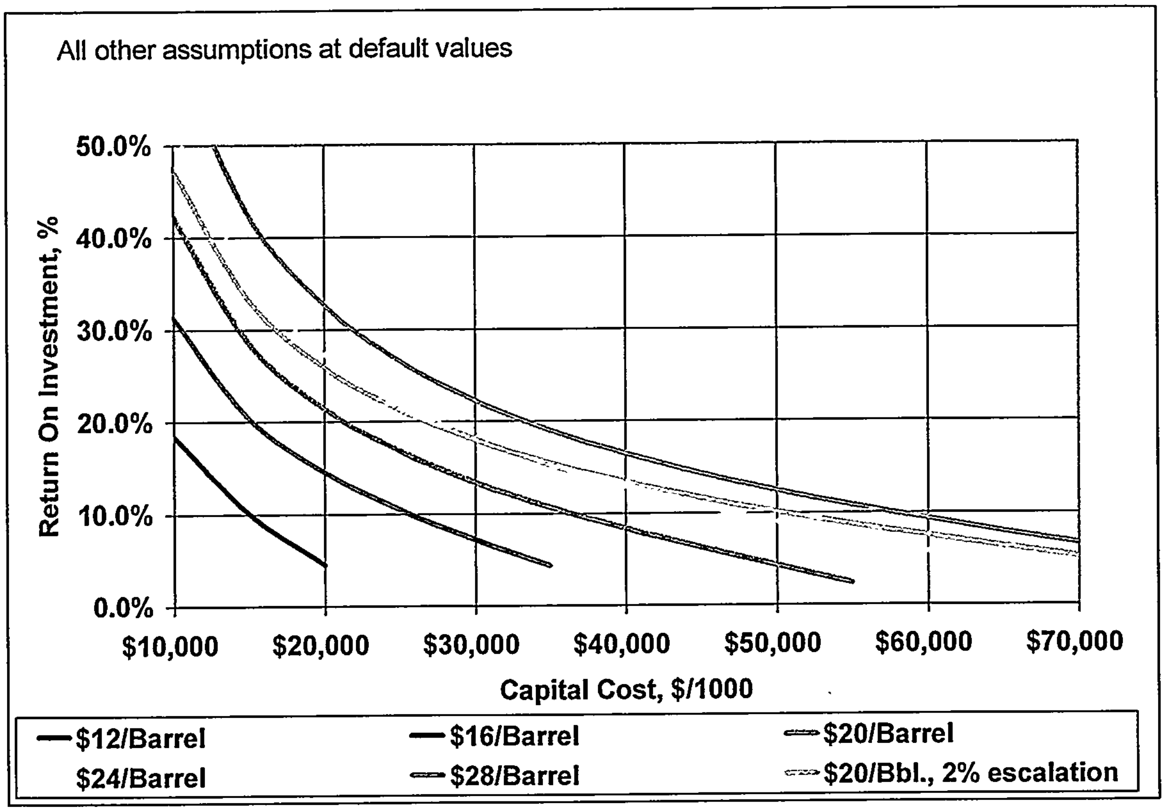


Figure 8–1: Impact of Fossil Fuel Cost & Escalation on Return on Investment

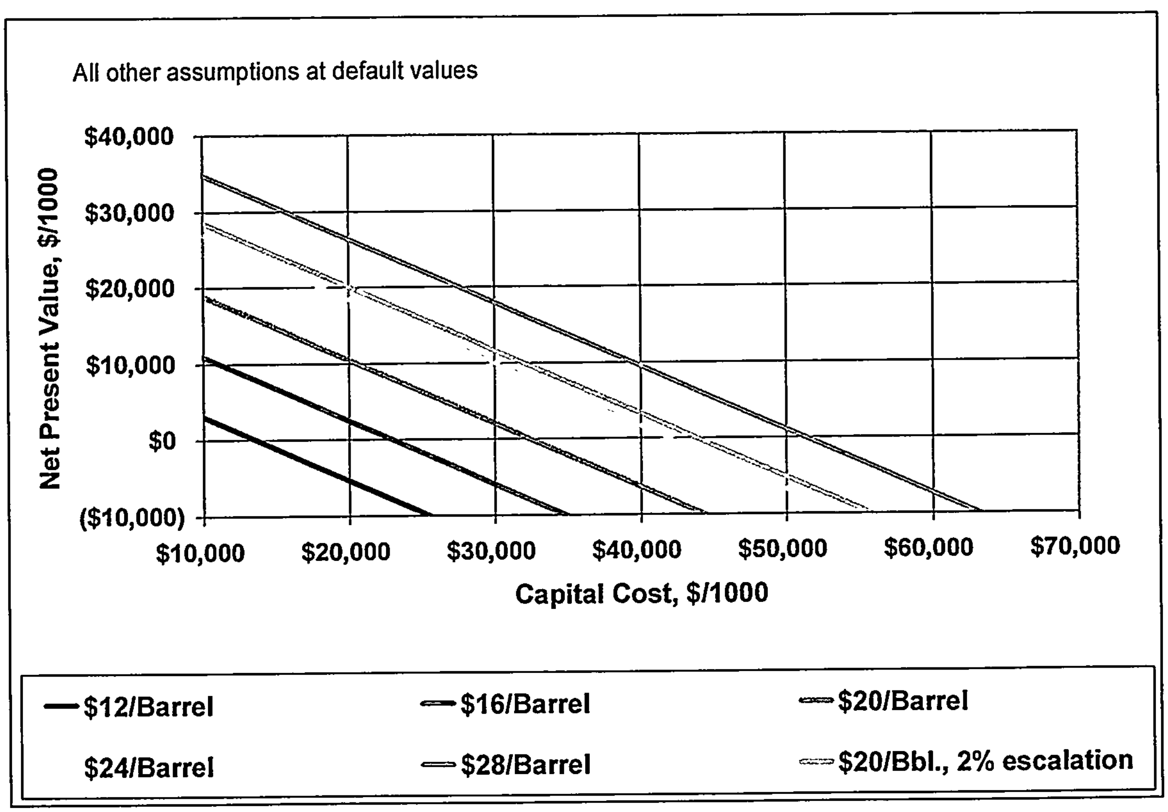


Figure 8–2: Impact of Fossil Fuel Cost & Escalation on Net Present Value

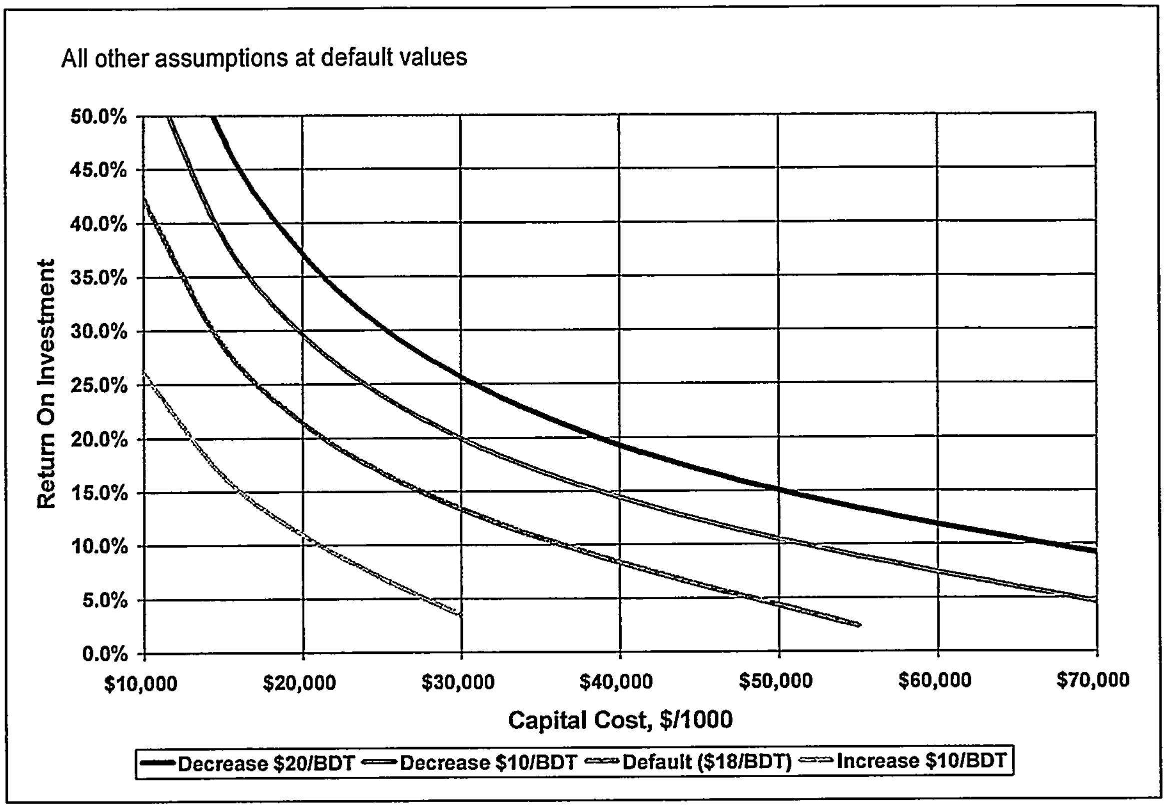


Figure 8–3: Impact of Average Biomass Fuel Cost on Return on Investment

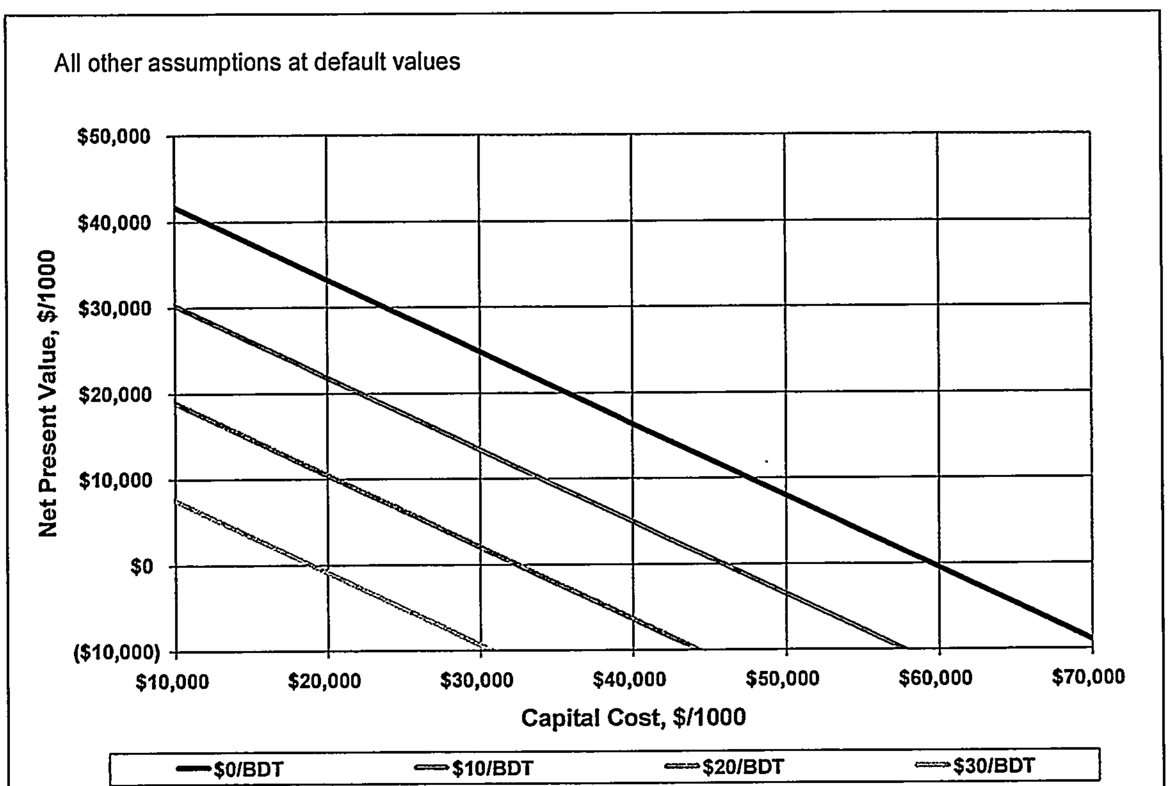


Figure 8–4: Impact of Average Biomass Fuel Cost on Net Present Value

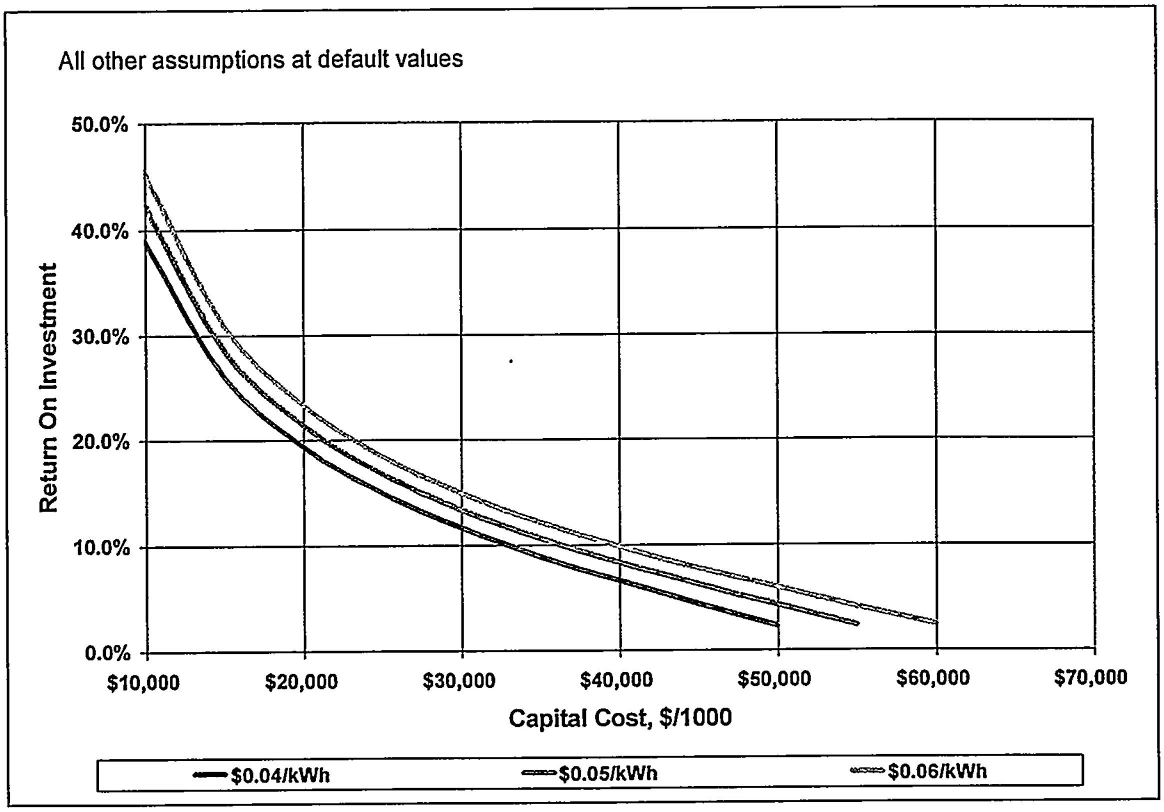


Figure 8–5: Impact of Displaced Purchased Power Value on Return on Investment

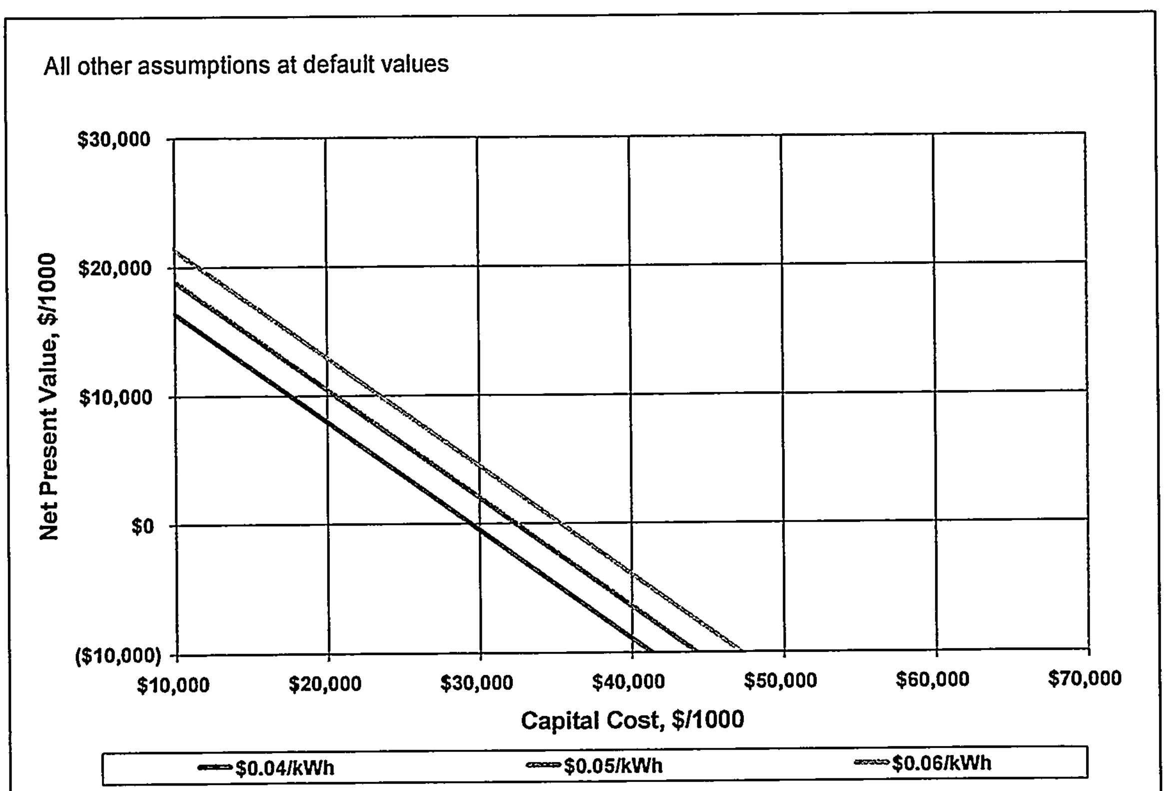


Figure 8–6: Impact of Displaced Purchased Power Value on Net Present Value

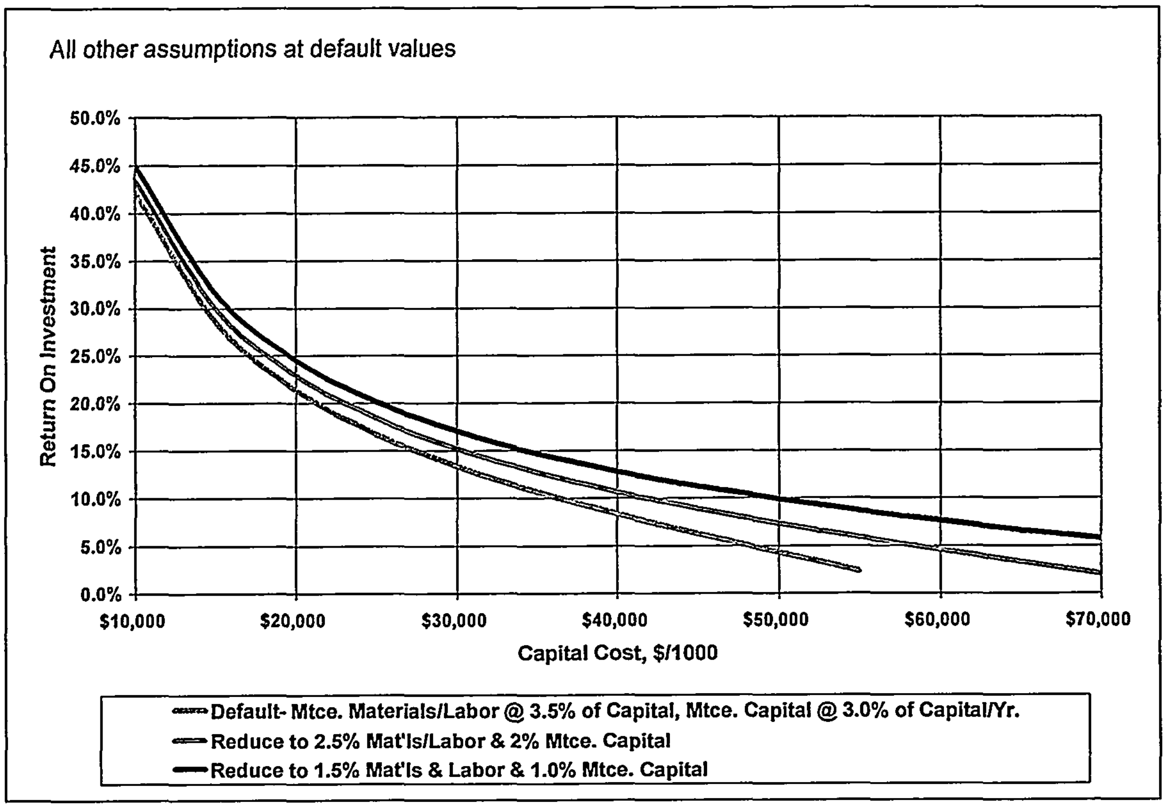


Figure 8–7: Impact of Maintenance Cost Assumptions on Return on Investment

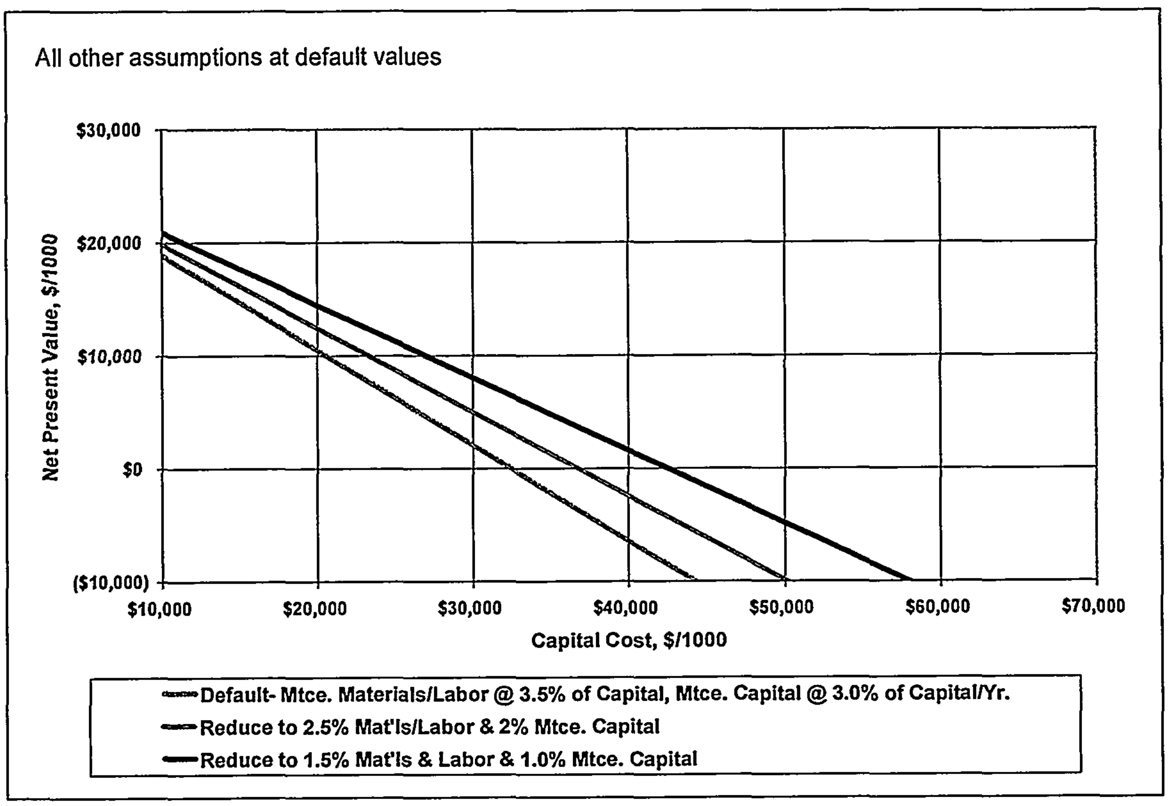


Figure 8–8: Impact of Maintenance Cost Assumptions on Net Present Value

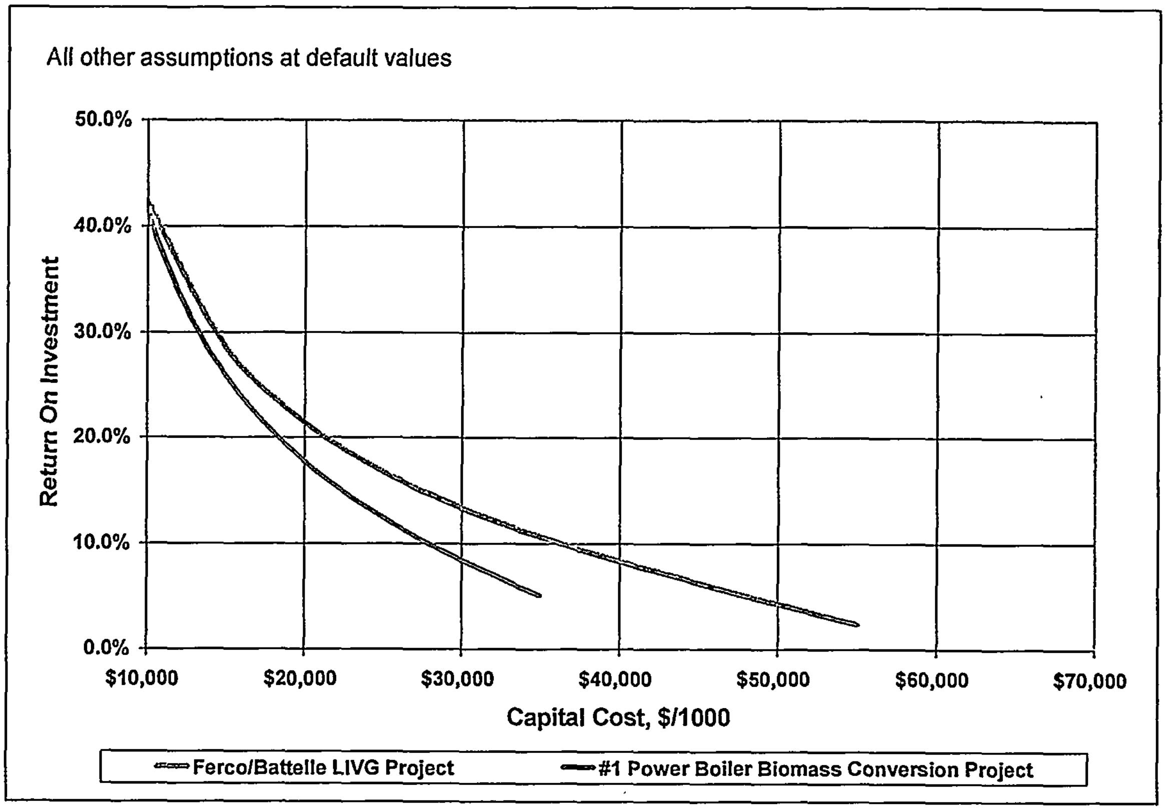


Figure 8–9: Comparison with No. 1 Power Boiler Relifing Project–Return on Investment

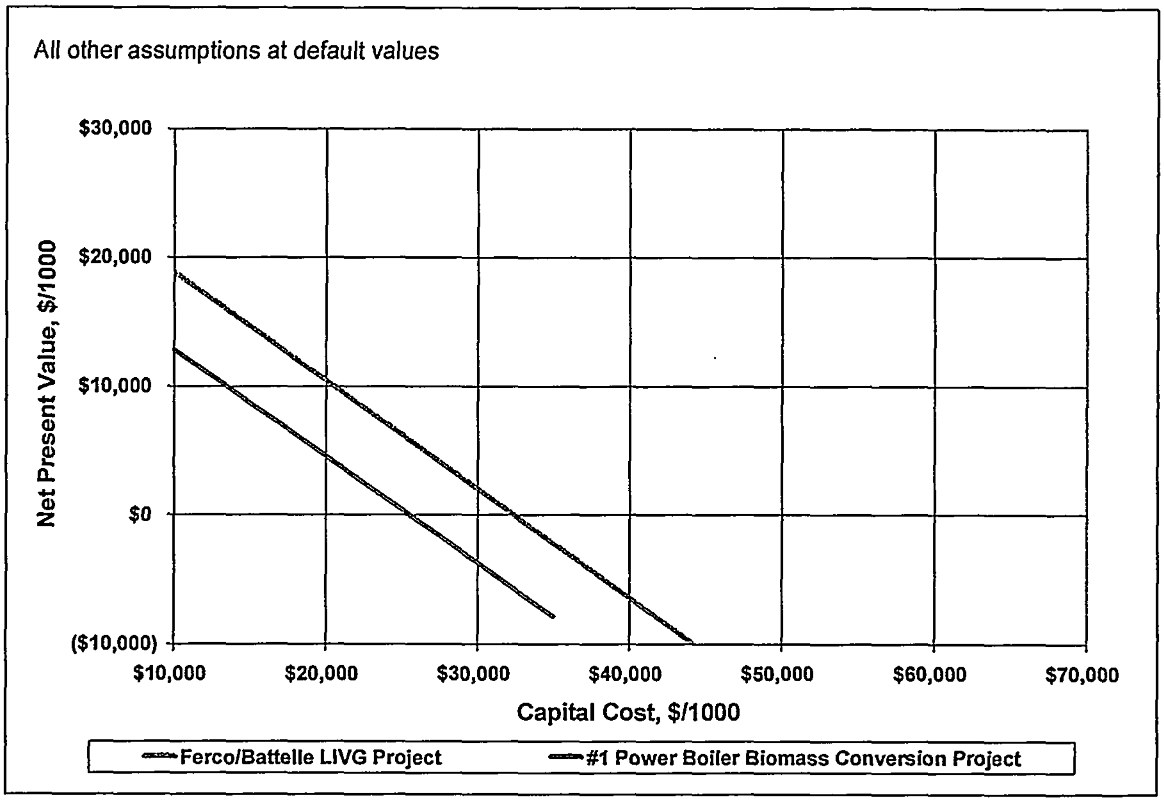


Figure 8–10: Comparison with No. 1 Power Boiler Relifing Project–Net Present Value

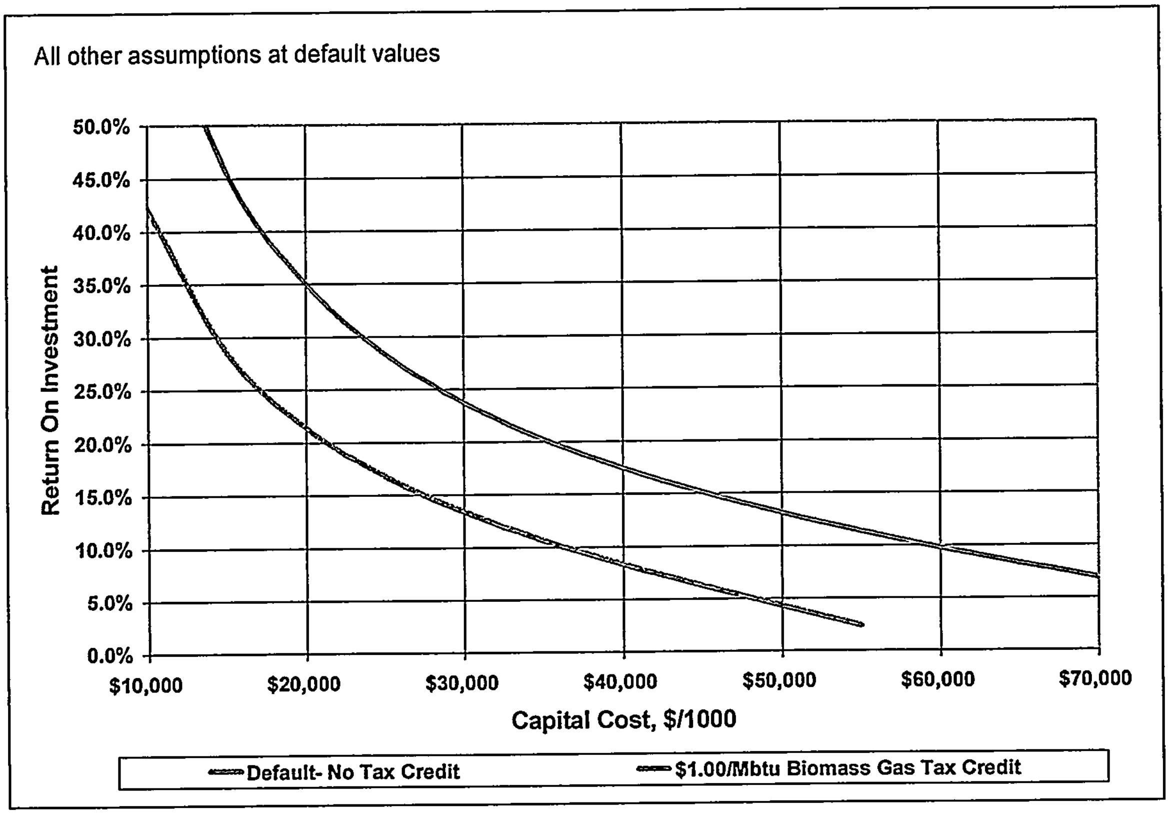


Figure 8–11: Impact of Fuel Gas Tax Credit on Return on Investment

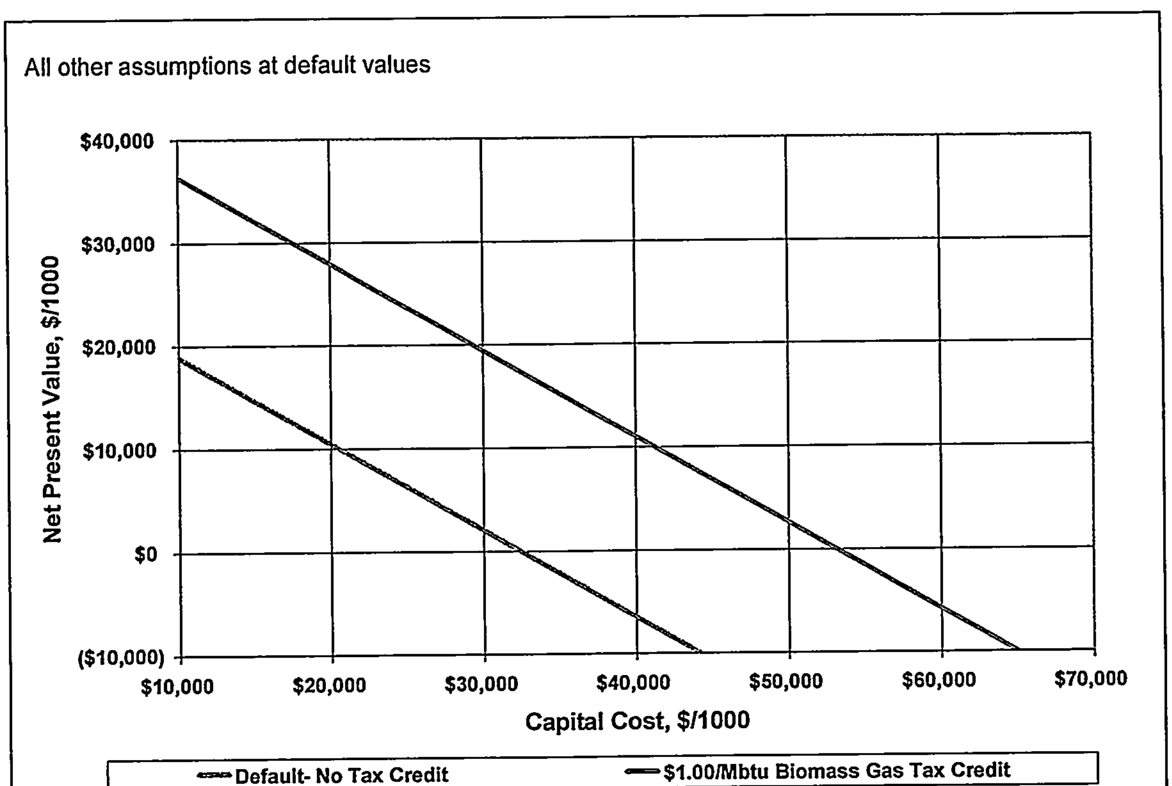


Figure 8–12: Impact of Fuel Gas Tax Credit on Net Present Value

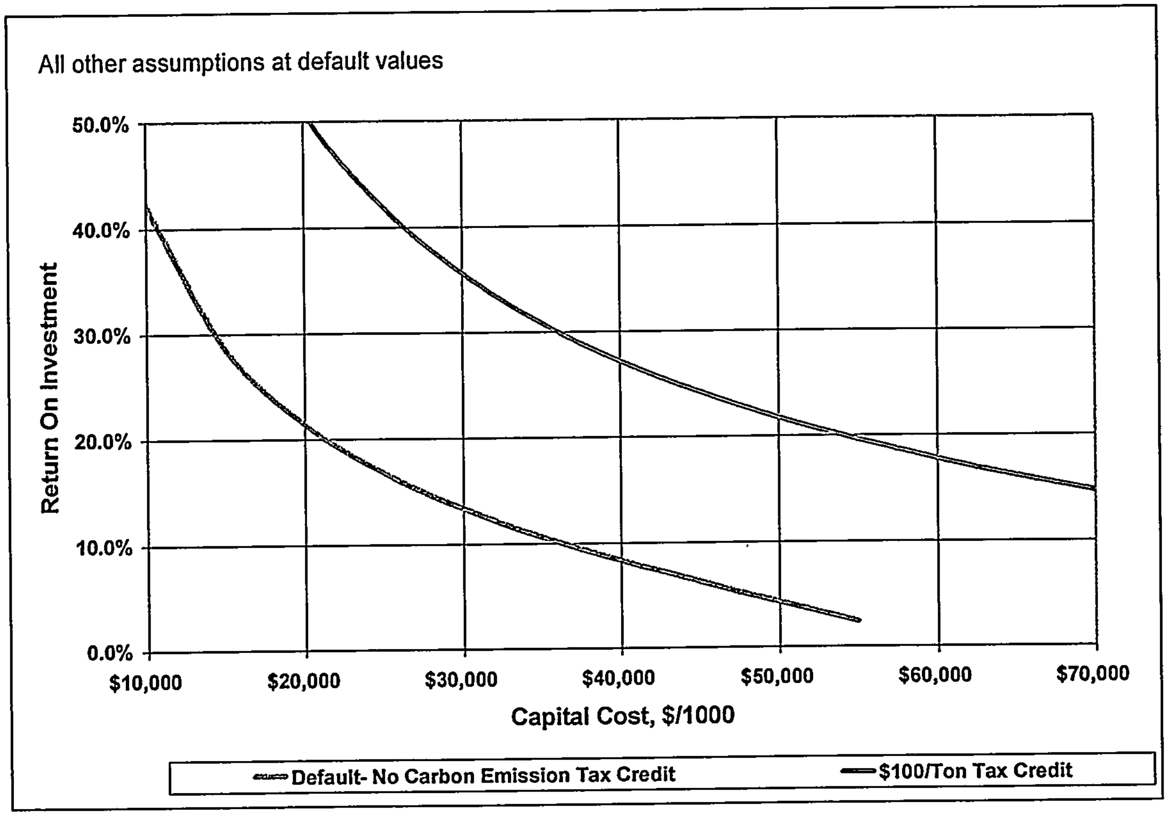


Figure 8–13: Impact of Tax Credits for Avoided Carbon Emissions on Return on Investment

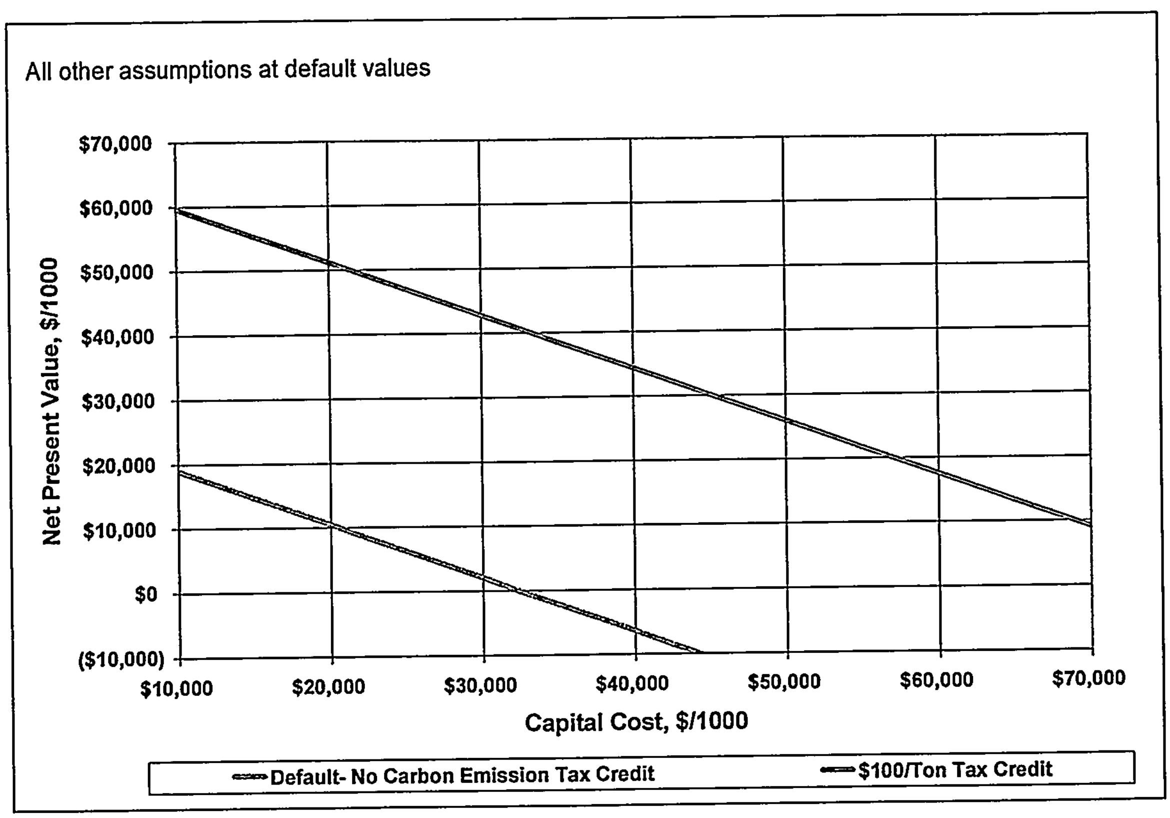


Figure 8–14: Impact of Tax Credits for Avoided Carbon Emissions on Net Present Value

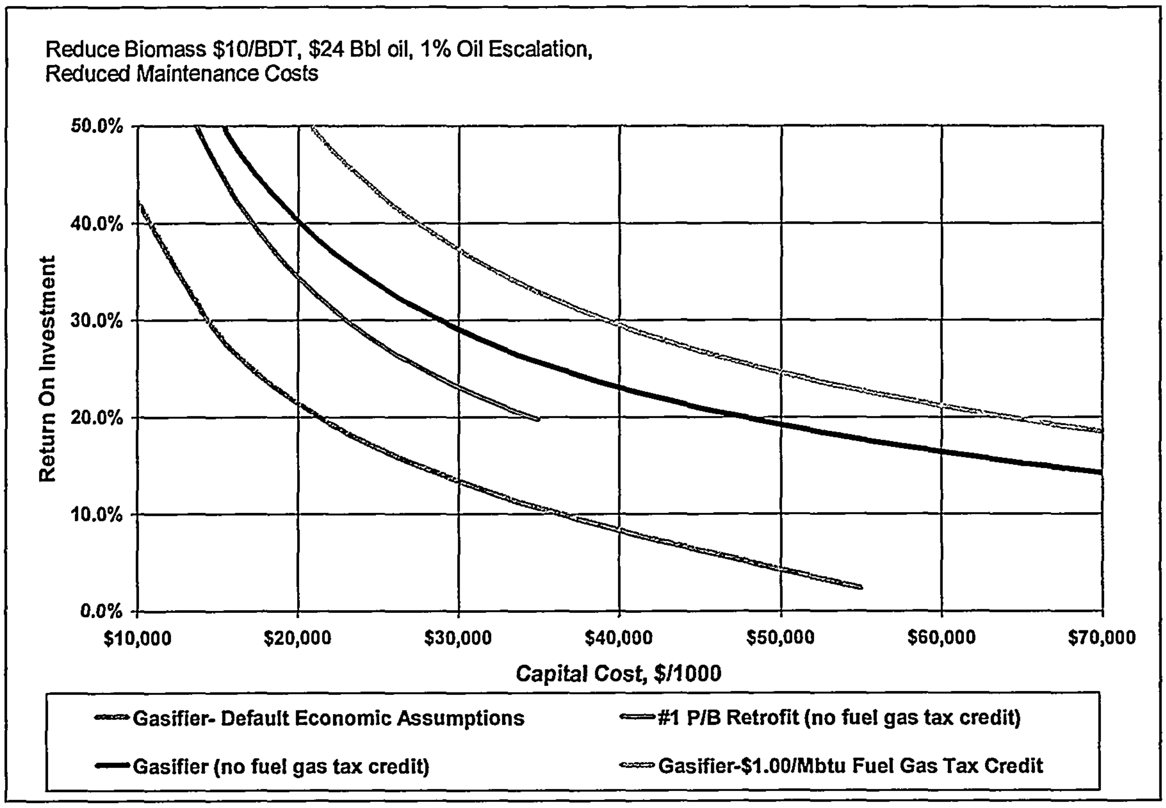


Figure 8–15: Impact of Favorable Economic Assumptions on Return on Investment

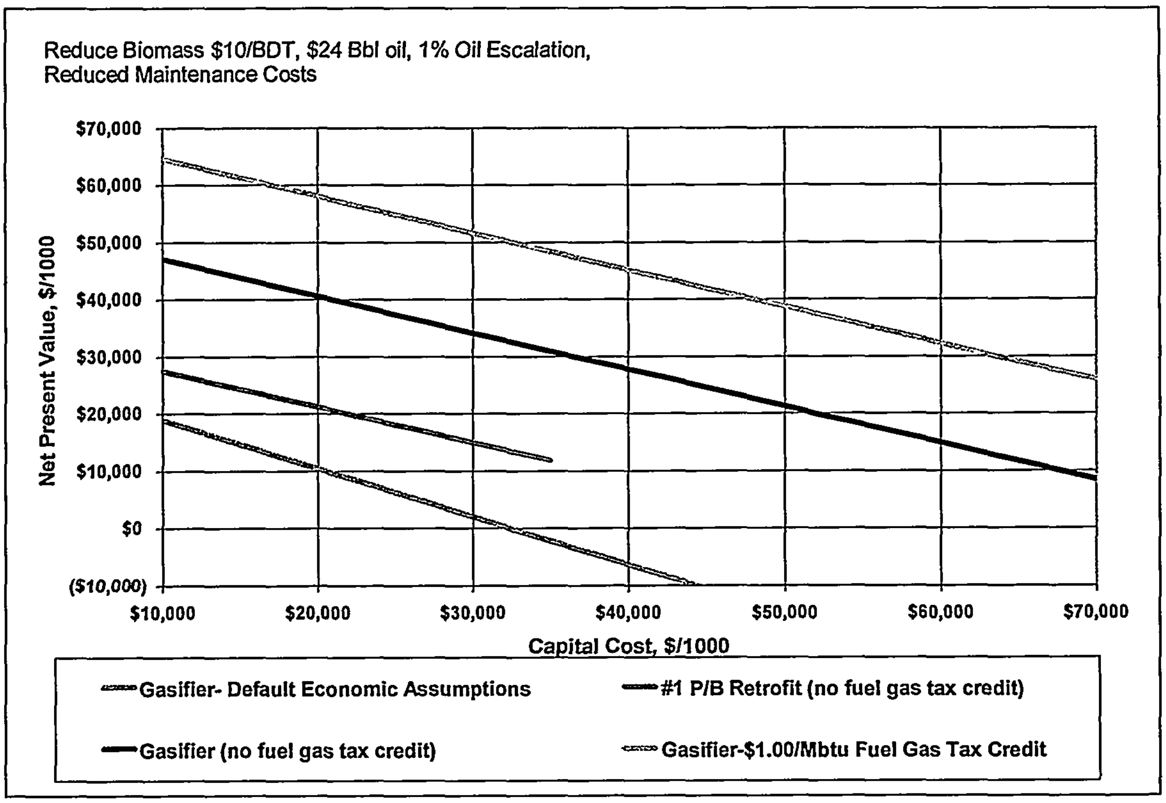


Figure 8–16: Impact of Favorable Economic Assumptions on Net Present Value

For purposes of this study, a range of ROI "hurdle rate" values from 12% to 19% has been defined to represent the minimum threshold required for project economic viability. The low end of the range has been set based on informal discussions with electric power industry independent power project developers. Given a commercially proven technology, this represents a minimum weighted average return to debt and equity project participants that constitutes an economically viable project. The 19% high end of the range is based on Weyerhaeuser's publicly stated goal of achieving financial performance of at least 19% return on net assets (RONA) in it's major businesses across the business cycle. Granted, projects with pro forma ROI forecasts of below 19% ROI can generate contributions greater than 19% RONA over the life of a project. The 19% ROI figure has been selected as a benchmark to represent the rate of return above which manufacturing companies may decide investment is warranted. Based on the above range of threshold returns, the Gasifier Project defined for New Bern will support a capital investment in the range of $22.0 million to $31.8 million using the default economic assumptions.

Figures 8–1 and 8–2 display the sensitivity of economic figures of merit to assumptions about initial oil price and assumed escalation rate. The default values ($20/barrel and 0.1% real escalation) are based on Energy Information Agency forecasts and recent New Bern experience, but recent volatility in oil markets makes even the determination of current trend price somewhat speculative. As seen in these figures, a $4/barrel movement in oil price is roughly equivalent to an increase in oil escalation rate from the default value to 2% (real)/yr. and increases economic value of the Gasifier Project (as measured by NPV) by roughly $9 million. Disruptions in oil markets, such as supply-side shocks, would clearly have a major impact on project viability.

As can be observed by examining Figures 8–1 through 8–8, significant deviations from the default values of key fuel and power cost and/or escalation assumptions are needed to bring project economic value into line with the estimated capital investment of nominally $70 million. Table 8–3 below takes each sensitivity parameter individually and back-calculates how far it would have to move in order to generate project ROI's in the threshold range for the "Next Plant" estimated capital cost.

Parameter	Default Value	Next Plant Capital Cost = $69.7M	
		Value for 12% ROI	Value for 19% ROI
#6 Fuel Oil Escalation, %/yr.	0.1%	5.8%	10.2%
Beginning Oil Price (2000), $/Bbl.	$20	$39	$56
Capital Cost Support (One Time Payment), $	N/A	$38M	$48M
Average cost of biomass , $/BDT	$18	-$8	-$34
Value of displaced purchased electricity, $/kWh	$0.05	$0.20	$0.33

Table 8–3: Escalation Factors for Economic Viability

Table 8–3 suggests it's unlikely that movement of any single fuel and power related parameter will change markedly enough to establish the Gasifier Project economic viability at the New Bern site in the absence of some manner of public policy-related initiative.

Figures 8–9 and 8–10 indicate that given the same ROI "hurdle rate" range and default economic assumptions, the No. 1 Power Boiler Relifing Project will support capital expenditure in the range of $18.6 million to $24.8 million. This range compares favorably with the estimated project capital of $22.6 million and suggests that further investigation regarding the viability of this project is warranted.

Given the much greater fossil fuel displacement which is afforded by the LIVG technology, it is somewhat surprising that the incremental value of the Gasifier Project above the Boiler Relifing Project isn't greater than is observed in Figures 8–9 and 8–10. Given the default assumptions, only $3.5 to $7.0 million in incremental capital investment is warranted in the threshold ROI range. This is due to several factors:

- The average biomass fuel cost is significantly higher for the gasifier option due to the higher volume of fuel required.
- Parasitic electrical loads are significantly higher for the gasifier case as can be seen from Table 8–1. This further increases the fuel requirements and average biomass fuel cost for the gasifier case.
- Operating manpower requirements for the gasifier case are higher due to increases in process equipment scope and fuel handling requirements.

Figures 8–11 through 8–14 briefly examine the impact of two forms of public policy incentive. Figures 8–11 and 8–12 demonstrate the impact on project economics of a biomass gas tax credit applied for the life of the project at $1.00/MBtu of fuel gas (based on higher heating value). The graphics indicate that the fuel gas tax credit by itself would not be sufficient incentive to project implementation given the default assumptions used in this analysis.

Figures 8–13 and 8–14 demonstrate the impact of a hypothetical tax credit for displacement of atmospheric carbon emissions. The tax credit assumes that the gasification project as operated at New Bern would displace carbon emissions from coal and fuel oil combustion by 70,000 tons per year. This figure is the sum of atmospheric carbon emissions estimated from the New Bern base case plus carbon emissions that would be displaced from a bituminous coal-fired power plant generating the same net amount of electricity as the two biomass alternatives (48,355 MWh/yr.). By comparison, 37,000 tons per year of avoided carbon emissions would result from implementation of the No. 1 Power Boiler Relifing Project.

Table 8–4 indicates the levels of several hypothetical public-policy incentives that would be necessary to achieve economic viability for the Gasifier Project as defined for New Bern. Conceptual options include a fuel gas tax credit, a tax credit for avoided atmospheric carbon emissions, or an emissions credit for avoided atmospheric carbon emissions (treated as taxable income). Table 8–4 also shows the range of capital cost subsidy needed to achieve threshold levels of economic return for the "Next Plant" case. Capital support as the only incentive to a Next Plant project would need to be in the range of 54 to 68 percent of the estimated capital cost of the facility to bring economic return into the threshold range.

Parameter	Next Plant Capital Cost = $69.7M	
	Value for 12% ROI	Value for 19% ROI
Fuel gas tax credit, $/MBtu (based on higher heating value of product gas)	$2.20	$3.79
Tax Credit for avoided atmospheric carbon emissions, $/ton avoided carbon emission	$94	$163
Emission credit (taxable) for avoided atmospheric carbon emissions, $/ton avoided carbon emission	$152	$262
Capital Cost Support (One Time Payment), $	$38M	$48M

Table 8–4: Public Policy Incentives–Levels for New Bern Gasifier Project Economic Viability

A wide variety of "what-if scenarios" could be created to determine what conditions would favor investment in the Gasifier Project at the New Bern site. Figures 8–15 and 8–16 exemplify one such case and makes changes in several important economic parameters to create a scenario more favorable to biomass utilization than is currently envisioned. The following economic assumptions are changed:

- Fuel oil initial price of $24/Bbl. rather than $20/Bbl.
- Fuel oil real escalation at 1% rather than 0.1%
- Average biomass fuel price reduced by $10/BDT
- Displaced purchased power value at $0.060/kWh rather than $0.050/kWh
- Maintenance costs (expense and capital) at 1.5% and 1.0% respectively, rather than 3.5% and 3.0%

As can be seen from the charts, these changes in assumptions bring the gasifier project returns into the threshold range at the estimated "Next Plant" capital cost. Incremental capital above what can be spent on the boiler retrofit option is also increased. It is interesting to note, however, that economic value above and beyond what is created by the No. 1 Power Boiler Relifing Project is only produced if public policy incentives (such as the fuel gas tax credit) are present. This can be seen by examining Figure 8–16 and is shown in Table 8–5.

Economic Assumptions	Biomass Gasifier Project Net Present Value—Capital = $69.7M	No. 1 Power Boiler Retrofit Project Net Present Value—Capital = $22.6M
Default values	-$30 M	$2 M
Favorable to biomass: • $24/Bbl. • 1% oil escalation • $0.06/kWh power • $8/BDT biomass • Reduced maintenance expenses and capital	$9 M	$20 M
Favorable biomass assumptions plus: • Add $1.00/MBtu fuel gas tax credit (Gasifier Project Only)	$26 M	$20 M

Table 8–5: Economic Value as a Function of Economic Assumptions

8.4.2 Discussion – Comparison to Biomass Gasification Combined Cycle (BGCC) Technology

The potential application of biomass gasification combined cycle (BGCC) technology at New Bern was investigated in the previous "New Bern Biomass to Energy Project Phase 1 Feasibility Study" (LOI No. RCA-3-13326) conducted in 1994-95. In that study, BGCC systems were defined for the New Bern site based on both the TPS and Tampella low-Btu gasification technologies. That study concluded that export power prices above $0.05/kWh in conjunction with capital subsidies for early implementations of the technology yielded a development path that could lead to commercially viable BGCC combined heat and power systems.

BGCC system configurations have not been proposed for New Bern in the current study, in part because regional power markets do not currently support the necessary power prices to make such a project viable. This and other factors dictated that gasification system configurations in the current study be defined with an emphasis on energy self-sufficiency.

In order to revisit the findings of the "New Bern Biomass to Energy Project Phase 1 Feasibility Study", information from that study has been used to compare the economic performance of a conceptual BGCC system to the economic performance of the biomass projects defined in the current study using the same economic assumptions and evaluation methodology. Heat and material balances for the BGCC technology option are based on the Tampella gasification technology using a steam dryer for fuel preparation. The balances have been adapted to allow direct comparison to the two biomass systems defined in the current study. Key performance parameters are defined in Table 8–6.

Description	BGCC System Value
Approximate capital cost (escalated to 2000 dollars)	$110 M
Net BGCC electrical output	39 MW
Net power export	34 MW
Net BGCC system usable thermal export	190-270 MBtu/hr.
Fuel requirement	319,000 BDT/yr.
Average fuel cost	$20/BDT

Table 8–6: Performance Parameters for BGCC Technology Comparison

The net thermal energy that can be exported from the BGCC system is stated as a range, depending on how much useful heat is recovered from the steam dryer exhaust stream. The mill's non-recovery thermal requirements can be met within the range stated in Table 8–6, although how dryer waste heat would be integrated to satisfy thermal process demands at New Bern has not been specifically determined. The average fuel cost displayed in Table 8-6 is based on biomass fuel supply data presented in Section 2 of this report. Economic assumptions used are the same as for the biomass projects defined in the current study. Economic performance of the BGCC system is compared to the biomass options of the current study in Figures 8–17 and 8–18 below.

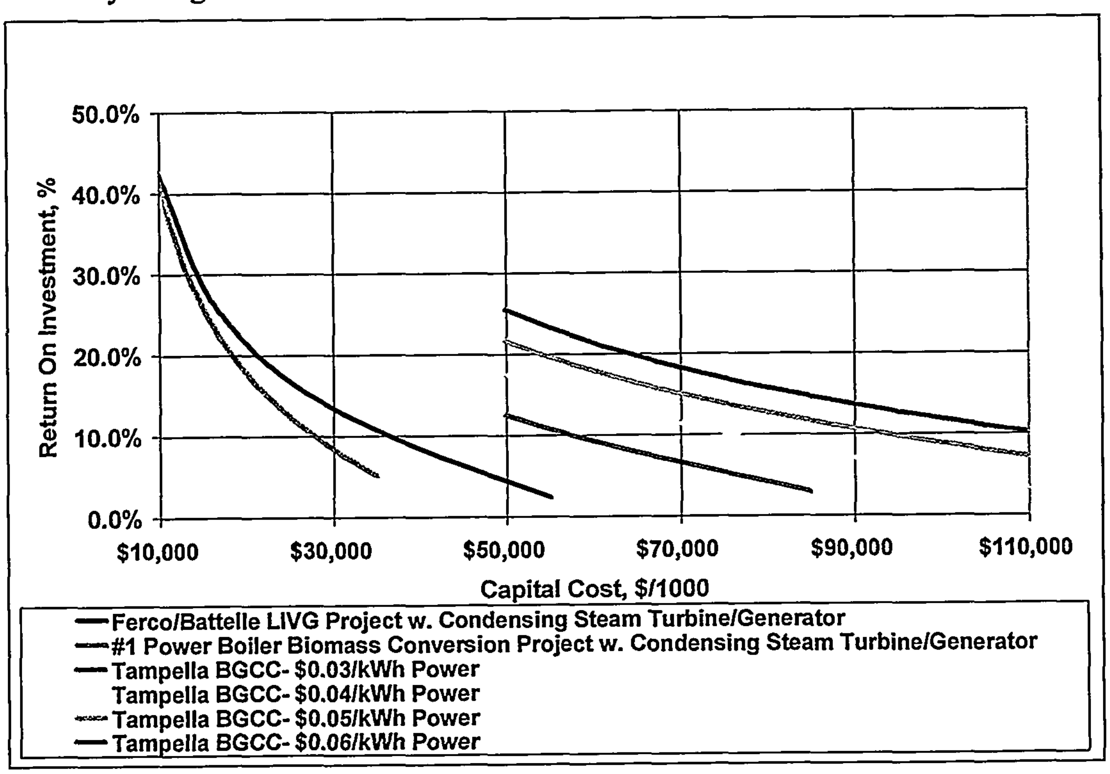


Figure 8–17: New Bern DOE Study Options vs. Tampella BGCC/LOI Study – Return on Investment

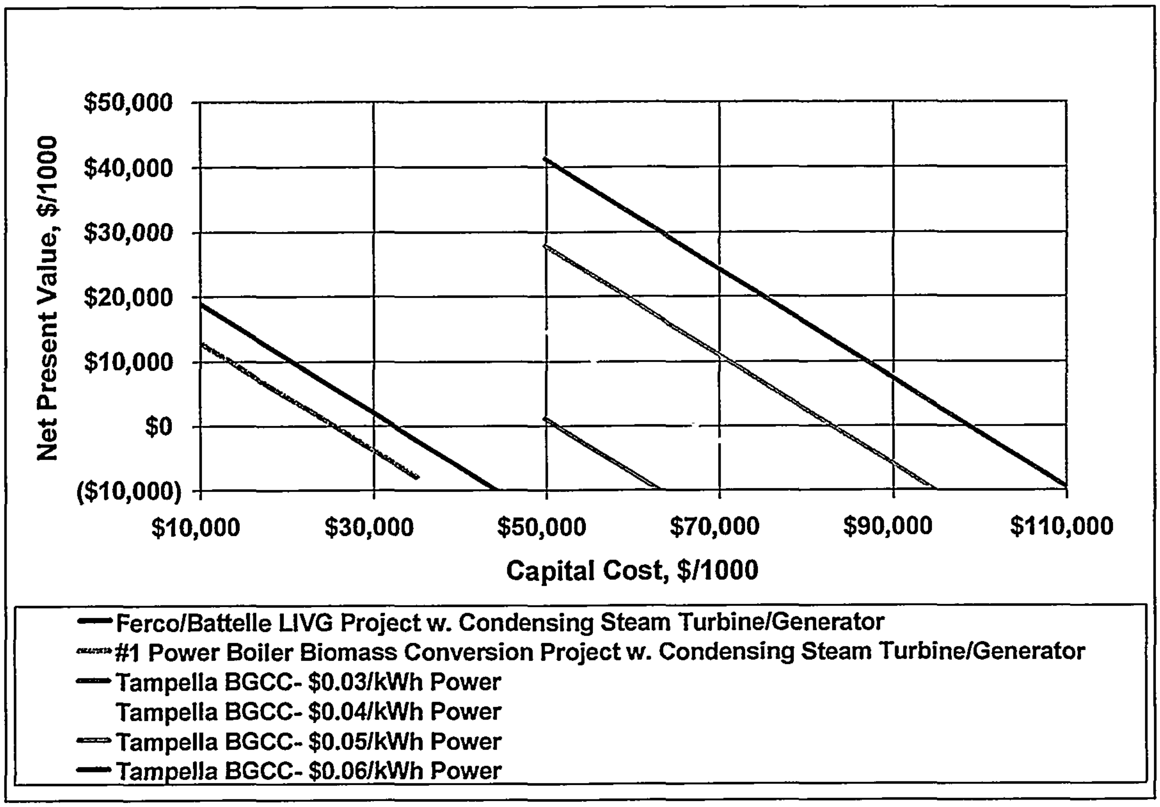


Figure 8–18: New Bern DOE Options vs. Tampella BGCC – Net Present Value

Again using an economic return threshold of 12-19% ROI, the BGCC option will support capital investment in the ranges shown below in Table 8–7 as a function of export power price.

Case Description	Estimated Capital Requirement	Supportable Capital at 19% ROI	Supportable Capital at 12% ROI
No. 1 Power Boiler Relifing Project with Condensing Steam Turbine	$23M	$19M	$25M
FERCO/Battelle LIVG Project with Condensing Steam Turbine	$70M	$22M	$32M
BGCC System with power sales at $0.04/kWh	$110M	$46M	$67M
BGCC System with power sales at $0.05/kWh	$110M	$57M	$83M
BGCC System with power sales at $0.06/kWh	$110M	$67M	$99M

Table 8–7: Supportable Capital Summary for New Bern Biomass Options

These results are consistent with findings of the New Bern Biomass to Energy Feasibility Study, indicating that a power price of $0.05/kWh or more would be needed to attain project viability.

8.5 Conclusions: New Bern Gasification Project Economic Analysis

The economic analysis of the Gasification Project option for New Bern indicates that, given default values of key economic assumptions, project viability would require significant external subsidy to the project in one form or another. Sensitivity analysis of key economic assumptions indicates that favorable shifts in several key economic assumptions would have to occur in concert to ensure the Gasifier Project's viability. Economic value creation above what is possible with conventional technology occurs only when favorable economic assumptions are combined with public policy incentives geared toward expanding biomass fuels utilization.

It is important to note that these conclusions are highly specific to the New Bern site. Key factors about the New Bern situation decrease the value of the gasification technology below what its value could be at other implementation sites. These factors include:

Biomass fuel market characteristics – Weighted average biomass fuel cost is ~$18/BDT at the volume required by the Gasifier Project. This is higher than may be the case in other regions—in part due to the local presence of a large biomass-fueled independent power producer (the 45 MW Craven County Wood Energy Project). In addition, the New Bern mill currently has a reasonably good market for selling its manufacturing residual. Economic return of both biomass projects suffer from the fact that implementation of either technology alternative means loss of fuel revenues to the site from fuel sales. This positive situation with respect to residual sales was uncertain when the project was conceived in 1996.

Presence of a boiler suitable for biomass firing – The conventional technology alternative in this case is based on retrofitting an existing boiler rather than installing a new biomass-fired boiler. The conventional technology option would look much less attractive were a new biomass-fired boiler required.

Low emphasis on electric power production – The New Bern situation does not currently lend itself to maximization of electric power production or the export of baseloaded electric power. A key prospective feature of the LIVG technology is its ability to use biomass fuels in combined-cycle power systems. This alternative was not considered in the current study, largely due to power market conditions. As shown in the BGCC technology comparison for New Bern (Figures 8–17 and 8–18; Tables 8–6 and 8–7) higher power values are necessary to support a BGCC-based approach. At the conception of the project, a resolved and attractive power market was anticipated.

Little opportunity for avoided capital expenditure – Biomass fuel conversion projects are sometimes driven, in part, by the need to invest significant capital in the existing facility in order to maintain the status quo. Examples would include capital expenditure (and associated operating costs) to mitigate SO_2 or NOx emissions. This situation does not currently exist at New Bern. In 1996, the need for a new power boiler was imminent. In fact, one was purchased, which removed the opportunity for avoided capital to be factored into the gasification alternative. Had the project been able to move more rapidly, this might not have been the case.

Favorable fossil fuel economic forecast – Assumptions for current fossil fuel cost and real escalation rate for New Bern are lower than may be the case for other localities. Comparison to a base case situation featuring natural gas as the default fuel with higher escalation assumptions would yield more favorable economics for a gasification-based energy project. In 1996, a 3.1% oil price escalation was anticipated. This is significantly higher than the consensus belief today.

Given the significant changes in the New Bern mill operating parameters and external factors impacting the project, it was realized in late 1998 that the likelihood of an early implementation at New Bern was low. With the DOE's concurrence, a scope change redirected the project to focus on opportunities for improving the capital and operating economics and defining the characteristics of a more viable implementation site. As a result, a generic gasification island was developed. Section 9 addresses the design and economic factors to be considered for selecting a site that will provide sustainable economics.

Section 9

Public Policy & Sustainable Economic Considerations

9.0 Public Policy & Sustainable Economic Considerations

9.1 Approach

As stated in the last section, the LIVG process economic performance at New Bern is negatively impacted by several factors. Key among these factors is that the biomass fuel market in the area is currently quite healthy compared to some other regions in North America, resulting in reduced spread between biomass and fossil fuel pricing. The existence of a power boiler on site that can be converted to biomass firing gives the mill a less capital intensive option for firing biomass than would be available to many other industrial sites. The current New Bern situation offers little opportunity for a gasifier project to displace other capital that would be necessary to sustain plant operation. In addition, although there is opportunity to displace a purchased electric load of modest size, the electric power market does not lend itself to development of base load power generation for sale to the power grid. Finally, the price and escalation assumptions used for future #6 oil utilization are not as favorable to biomass alternatives as pricing assumptions would be for a site firing natural gas. Many of these elements are quite different now than when the project was conceived in 1996.

The intent of presenting a "Generic" look at economics of the LIVG process is to provide potential users of the technology with a starting point for understanding what conditions favor its use. To that end, economic performance projections are presented for a broader array of biomass and fossil fuel costs than in the previous section. In addition, projections are added for different levels of capacity utilization. As before, economic figures of merit are displayed as a function of capital employed. By incrementing the Nth Plant Design Generic Application Capital Cost Estimate (see Table 5–6) to better reflect a given site's situation, a feasibility-level capital cost can be estimated for a specific user's situation at the same fuel processing capability (790 BDT/day). Appropriate scaling adjustments would need to be made by the reader for systems at other sizes.

The "Generic" assessment of economic viability of the FERCO-LIVG process is conducted using the same basic methodology used to evaluate the New Bern projects. A base case and LIVG project case are defined as was done for New Bern. Assumptions have been changed to reflect a typical industrial fossil fuel use situation where biomass retrofit may be considered. Key elements of the analysis are highlighted below:

- LIVG process performance assumptions remain unchanged.
- LIVG product gas substitutes for fossil fuel at the host site at equal thermal efficiency.
- Steam from the product gas HRSG and surplus waste steam from the fuel dryer are valued at the value of steam generated from fossil fuel in the base case. This implies there is a process steam load large enough to consume at least this amount of steam on a year-around basis.
- The host site operates on a 355 day, 24 hour/day basis.
- Consistent with the Generic capital cost estimate (Table 5-6), no condensing steam turbine is included.

- There is no credit for "avoided capital" which must be spent in the base case. Readers can examine this impact by adjusting the capital required for their site to reflect the impact of avoided capital spending.

Potentially, the most promising commercial application of the LIVG process is in providing fuel to combustion turbines in combined cycle application. The above approach was chosen in order to separate the economics of fuel substitution from the economics of power generation. Thus, as long as the "export steam product" of the LIVG process can be used, this comparison is indifferent to whether the product gas fires a boiler, a combustion turbine, or a direct-fired process heater. The key factor is that the medium-Btu product gas from the LIVG process be directly substitutable for the fuel currently in use. This analysis assumes the fuel utilization efficiencies are the same, although minor differences in utilization efficiency will not have material impact on the results and conclusions drawn from the analysis. Limitations of this approach are that it does not recognize any synergy or economic value that that may result from combining biomass fuel utilization and export power production (e.g., potential "green power applications").

As in the New Bern-specific economic case, results of the economic analysis are presented as a function of capital requirement in order to focus on what level of capital expenditure can be supported by the economic benefits provided by the project. This analysis does not differentiate "Next Plant" from "Nth Plant" in process performance from either a thermal or reliability/operability perspective; the LIVG process is defined to have a high level of thermal efficiency and is assumed to operate with a level of reliability that is normally expected of fully commercial process systems in continuous process industries. Therefore, evaluation of economic results at the "Generic Plant Capital Cost" of $50.0M (see table 5–6) allows inferences to be drawn regarding economic viability of Nth plant applications of the process.

9.2 Overview of Alternatives

Table 9–1 below summarizes the major impacts of the generic LIVG project on the fuel and purchased power requirements of the host site. As seen in the table, the only electrical cost impact to the project is from the electrical load of the new gasification island. Appropriate parameters have been zeroed out so that the table shows only incremental values for the key parameters.

Parameter	Base Case: Generic Fossil Fuel User	LIVG Process Retrofit
Capital Cost	0	$50.0 million (Nth plant)
Fossil Fuel Use	546.3 MBtu/hr.	0 MBtu/hr.
Capacity Utilization	N/A	80%
Disposition of Site Fuel Residuals	N/A	N/A
Purchased Biomass Fuel	None	33.41 BDT/hr. (full load)
Purchased Electric Power	N/A	3,990 kW incremental to base case (gasification island load)

Table 9–1: Overview of the Generic LIVG Project

9.3 Analytical Method, Assumptions and Key Inputs

As in the New Bern case, the net economic benefits the generic LIVG retrofit project are reduced to an after-tax cash flow stream. Economic assumptions are the same as for the New Bern case with qualifications as follows:

Investment tax credits (North Carolina-specific) – Retained at 15% for biomass projects. Although this tax credit structure is North Carolina-specific, it was retained for the generic case in that other states may have measures which encourage increased utilization of renewable fuels. The relative importance of this factor will be investigated as part of the project sensitivity analysis.

Depreciation schedules & tax credits – Five year double declining balance (DDB) depreciation was used in the New Bern analysis whereas fifteen year DDB is more typical for industrial equipment. This preferential treatment for biomass options was retained for the generic case. The importance of this assumption is examined through sensitivity analysis.

Project residual values – Based on after-tax cash flow in last year of operation

The operating cost/benefit impacts of the generic LIVG project are considered in the following cost categories:

Biomass fuel cost – Biomass fuels similar in specifications to those found in the New Bern case are purchased on the open market. The analysis focuses on what biomass costs are required for project viability. It is assumed that average moisture of fuel into the LIVG process is 50%, wet basis. Biomass fuel prices are escalated at the nominal rate of inflation (zero percent real price escalation). The default value of biomass fuels used when investigating the sensitivity of other key economic assumptions is $10/BDT, half the average biomass cost used in the New Bern cases. This is an arbitrary figure intended to reflect a host site fuel supply which is favorable to new biomass energy projects. Biomass fuel cost sensitivity is investigated from $0/BDT to $30/BDT (roughly equivalent to typical coal pricing).

Fossil fuel cost – Biomass fuel utilization displaces fossil fuel in host site users at the same fuel utilization efficiency as in the base case. A default value of $3.00/MBtu is used for fossil fuel with fossil fuel price as a major parameter investigated in economic sensitivity analysis. This value is midway between EIA average year 2000 values cited for residual oil and natural gas. Fossil fuel price real escalation is assumed at a default value of 1.0%/yr., in line with EIA "Reference Case" projections for natural gas pricing for industrial users . A thermal credit for surplus dryer exhaust steam is given as in the New Bern project case. Fossil fuel use is assumed as "back-up fuel" 4% of operating time to cover biomass fuel system operating issues.

Purchased electric power – Purchased power escalation assumptions are the same as used in the New Bern cases. Gasifier island electrical load is costed at $0.044/kWh consistent with EIA average industrial electric power prices.

Operating labor – Labor for the biomass alternatives is added based on the staffing requirements estimated in Section 7.6.1. Fully loaded labor rates of $22/hr. are used and are assumed to escalate at the nominal inflation rate.

Maintenance costs – Expensed maintenance labor and materials are estimated to be 3.5% of initial capital per year escalated at the nominal inflation rate. Maintenance capital is added at 3%/yr. These values are based on pulp and paper industry experience and data.

Boiler Feedwater, Waste Water Treatment, Cooling Water and Miscellaneous Chemicals/Operating Supplies – Allowances are made on a case-specific basis and escalated at the nominal inflation rate.

9.4 Results and Discussion: Generic LIVG Process Economics

Results of the economic analysis are shown in the following paired graphics, Figures 9–1 through 9–16. As in the New Bern cases, when an acceptable ROI "hurdle rate" is specified, the figures allow estimation of how much capital can be spent to capture the economic benefits provided by the project. The economic value of the project can then be estimated from the accompanying NPV graphic. In all figures, the green trend lines represent the use of the "default" assumptions for all parameters (except capital cost).

The following sensitivities are investigated independently:

- Oil and biomass price sensitivity: Figures 9–1 through 9–8
- LIVG system capacity utilization: Figures 9–9 and 9–10

The impact of current public policy incentives for biomass utilization is examined in Figures 9–11 and 9–12 where economic figures of merit are compared with and without preferences applied to biomass projects in the area of investment tax credit and depreciation schedule. The potential impact of public policy-based incentives to encourage expanded use of biomass fuels is also investigated. Figures 9–13 and 9–14 demonstrate how LIVG project ROI and NPV are affected by a $1.00/MBtu biomass fuel gas tax credit. Figures 9–15 and 9–16 demonstrate the potential impact of tax credits associated with reduction of atmospheric carbon emissions assuming that biomass substitution (from renewable sources) for fossil fuels would qualify for such tax credits.

9.4.1 Economic Assumptions

Table 9–2 summarizes the default assumptions used in this analysis and embodied in Figures 9–1 through 9–16.

Parameter	Default Value
General inflation rate, %	2.5%
Discount rate, %	12%
Income tax rate, %	38%
Investment tax credit	15% for biomass projects 5% for other capital projects
Tax depreciation	5 yr. double declining balance for biomass projects 15 yr. double declining balance for other capital projects
Project life	25 years
Displaced fossil fuel, $/MBtu.	$3.00
Real escalation rate – fossil fuel, %	1.0%
Average Power Cost – ¢/kWh	4.4¢
Real escalation rate – purchased electric power	2000–2005: -0.5%/yr. 2006 –2010 -1.0%/yr. 2011–2015 +0.7%/yr. 2016 to end -0.3%/yr.
Average biomass price, $/BDT	$10 (at Gasifier Project volume)
Maintenance capital requirement, % of capital/yr.	3.0%
Maintenance materials and labor, % of capital/yr.	3.5%
Capacity Factors (based on 365 day year)	Mill- 92% Gasifier Project- 88%
Start Up Dates	Gasifier Project- 2003
Capital Spending Period	Gasifier Project- Two Years

Table 9-2: Summary of Default Economic Assumptions (Generic Case)

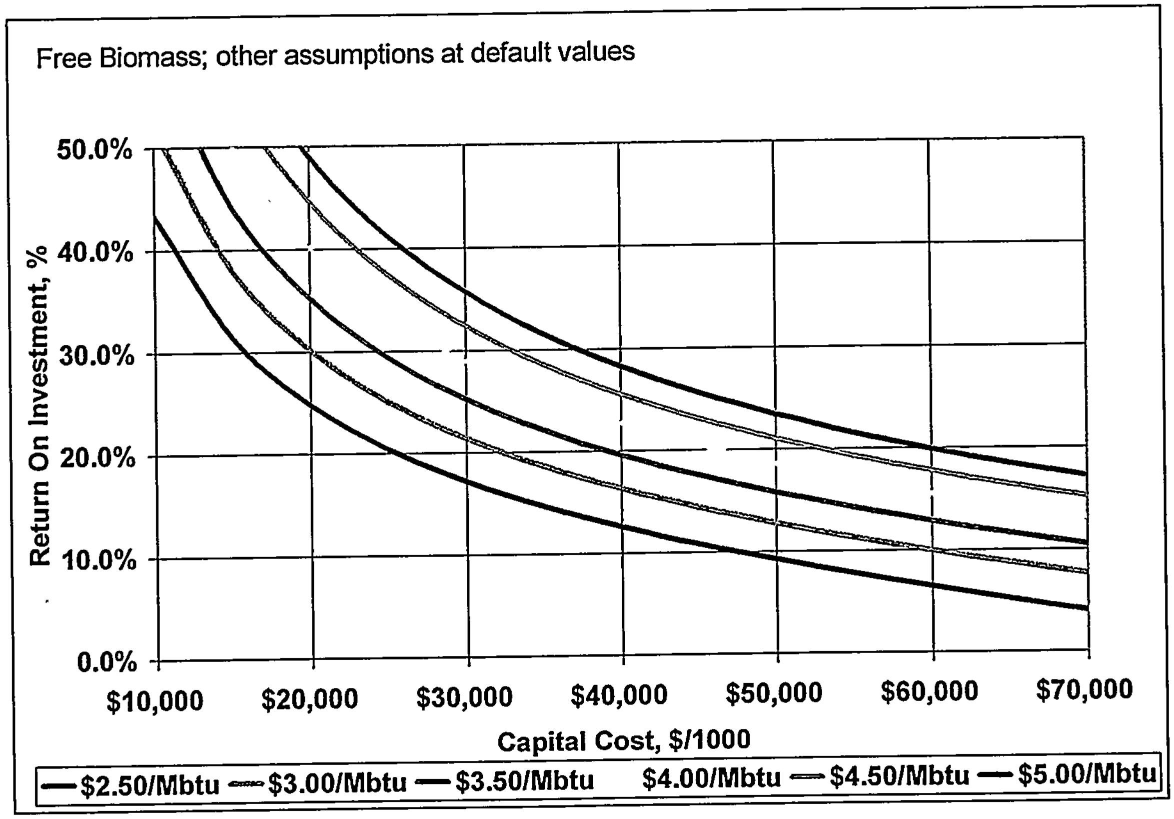


Figure 9–1: Impact of Fossil Fuel Cost on Return on Investment

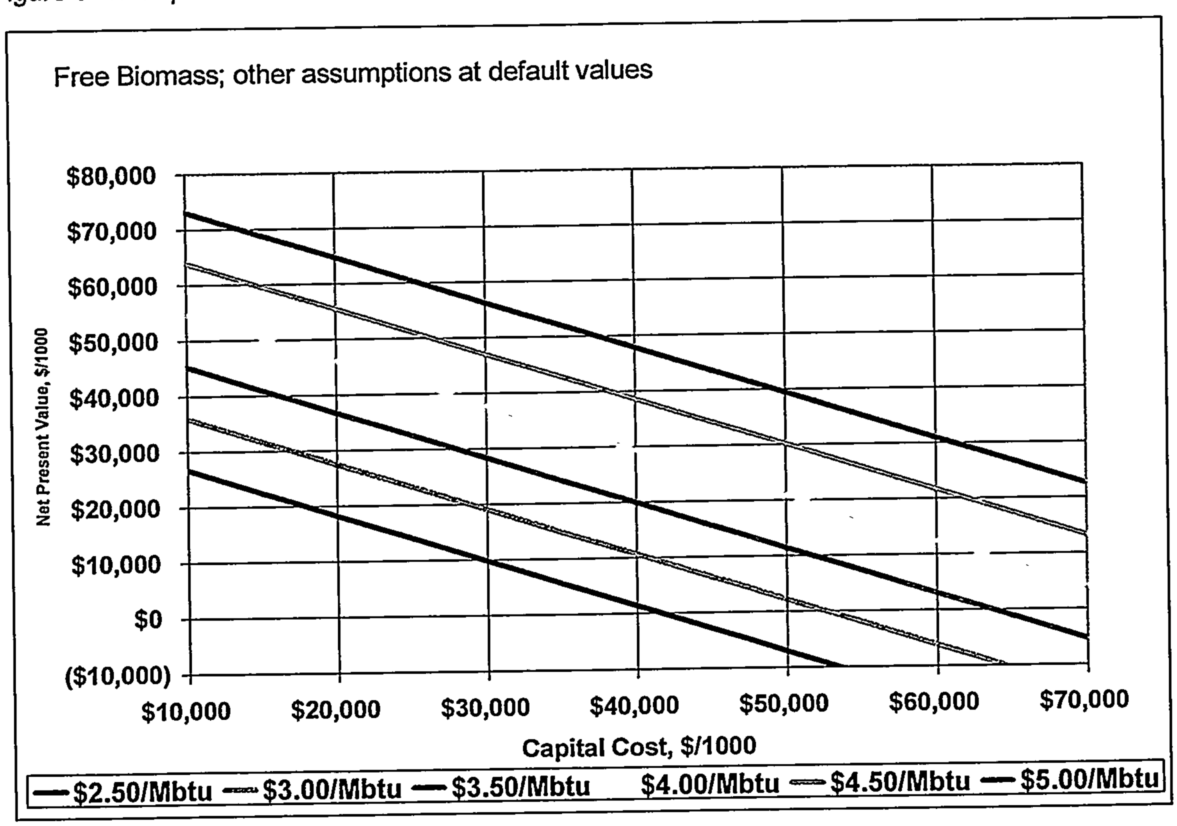


Figure 9–2: Impact of Fuel Costs on Net Present Value

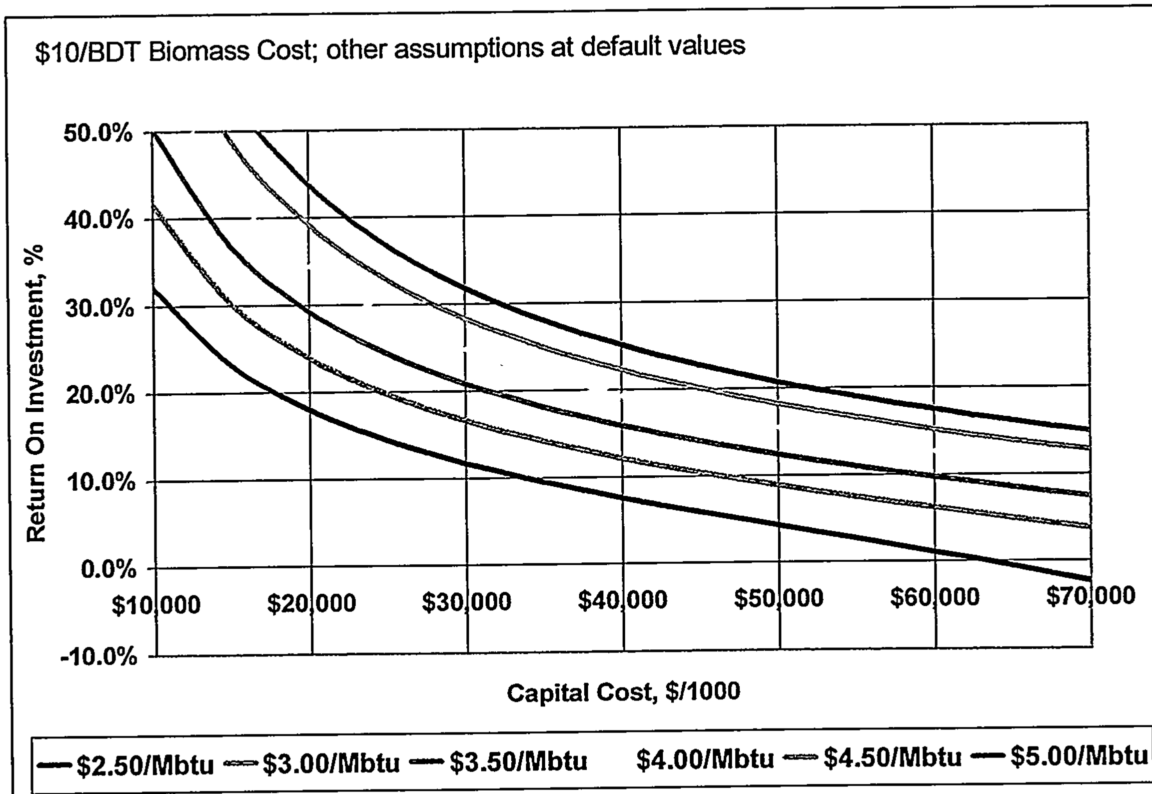


Figure 9–3: Impact of Fossil Fuel Cost on Return on Investment

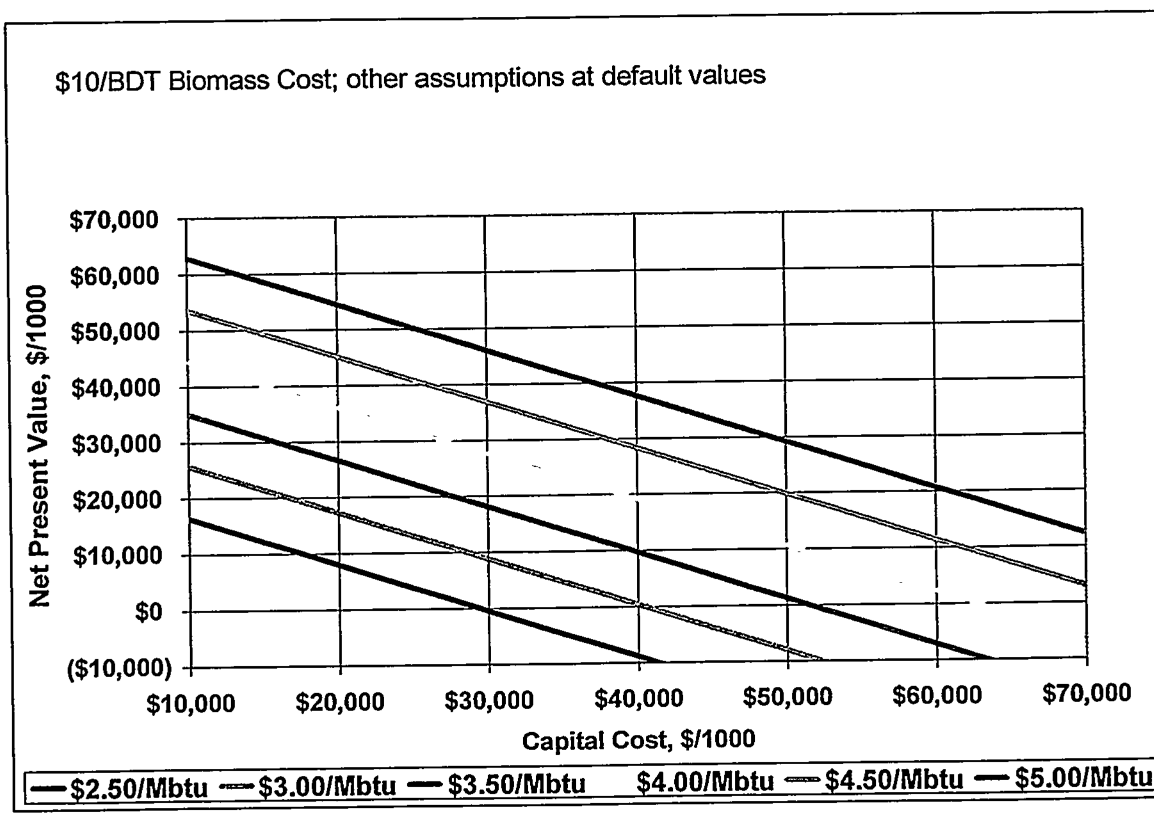


Figure 9–4: Impact of Fuel Costs on Net Present Value

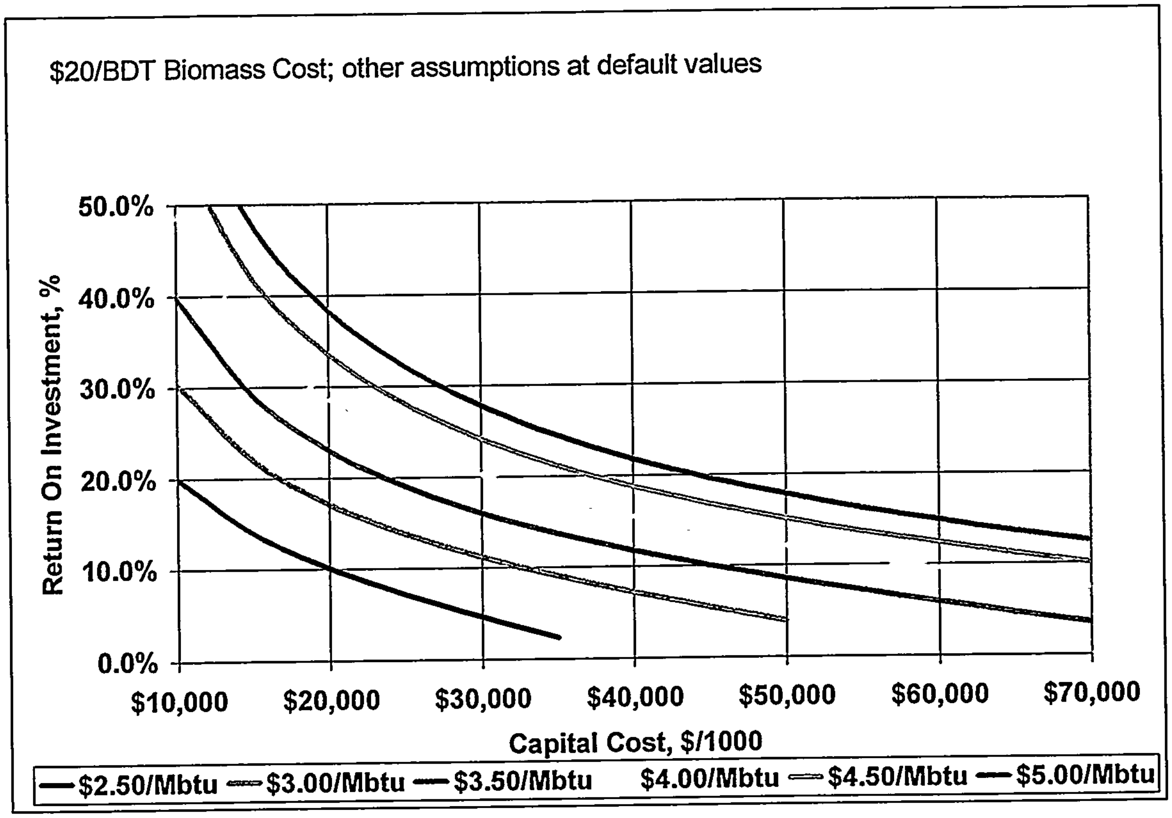


Figure 9–5: Impact of Fossil Fuel Cost on Return on Investment

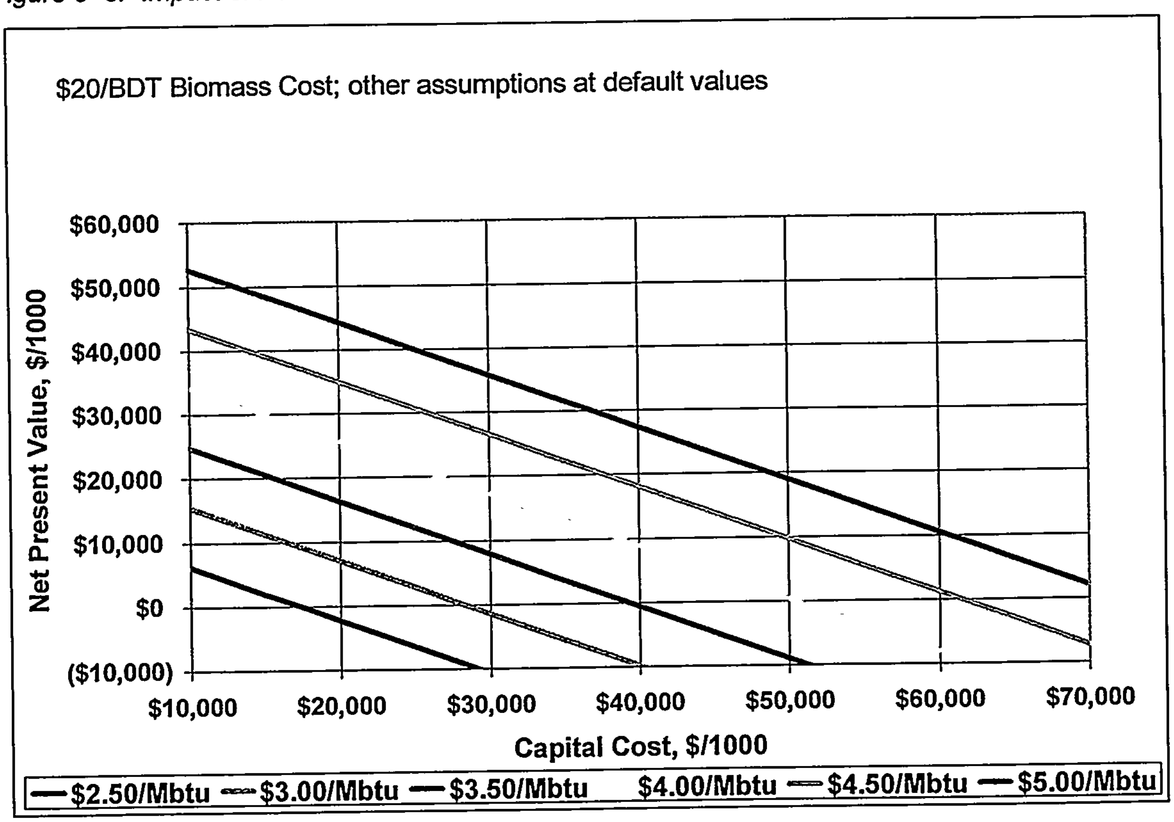


Figure 9–6: Impact of Fuel Costs on Net Present Value

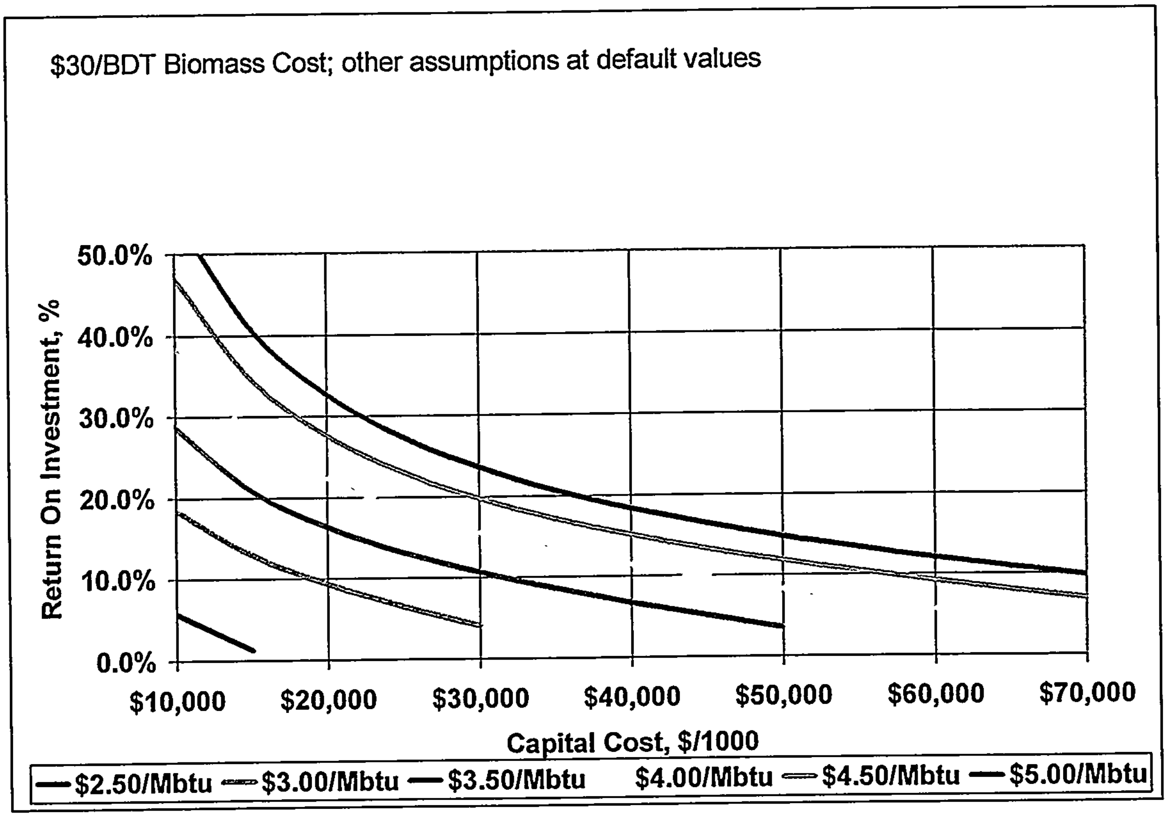


Figure 9–7: Impact of Fossil Fuel Cost on Return on Investment

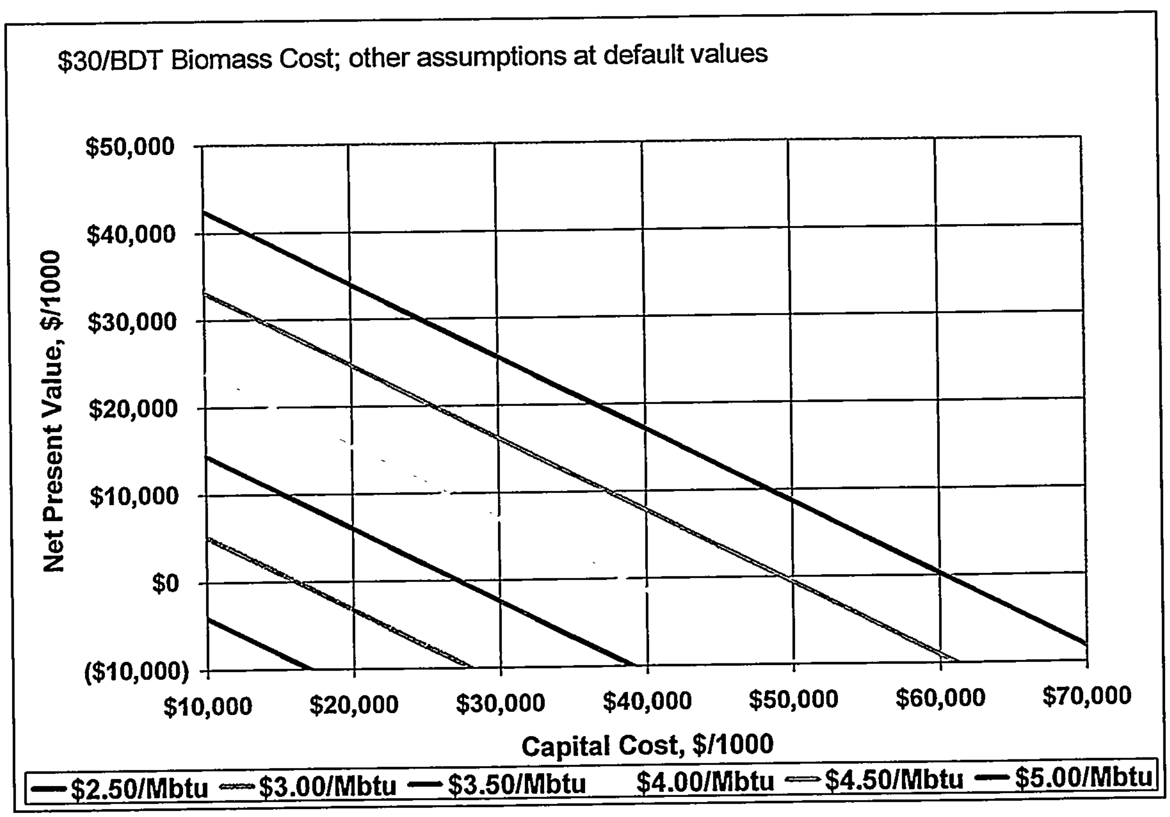


Figure 9–8: Impact of Fuel Costs on Net Present Value

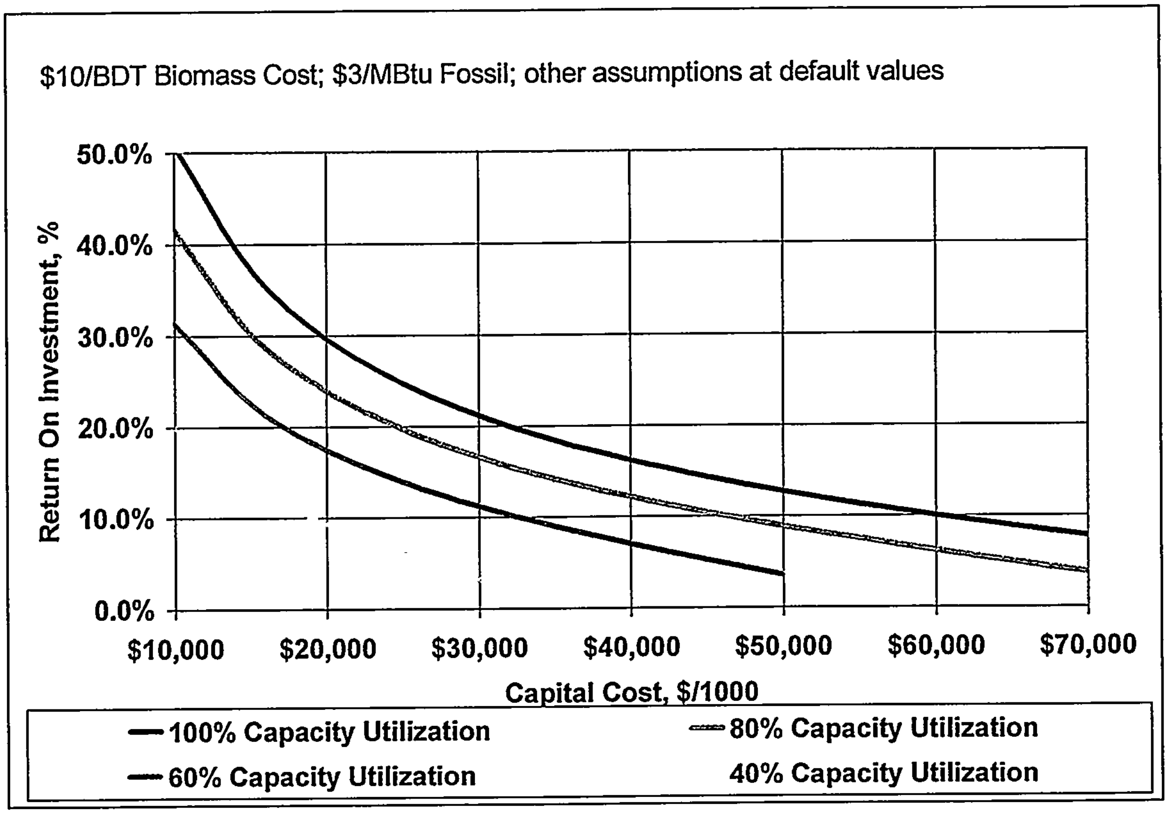


Figure 9–9: Impact of Capacity Utilization on Return on Investment

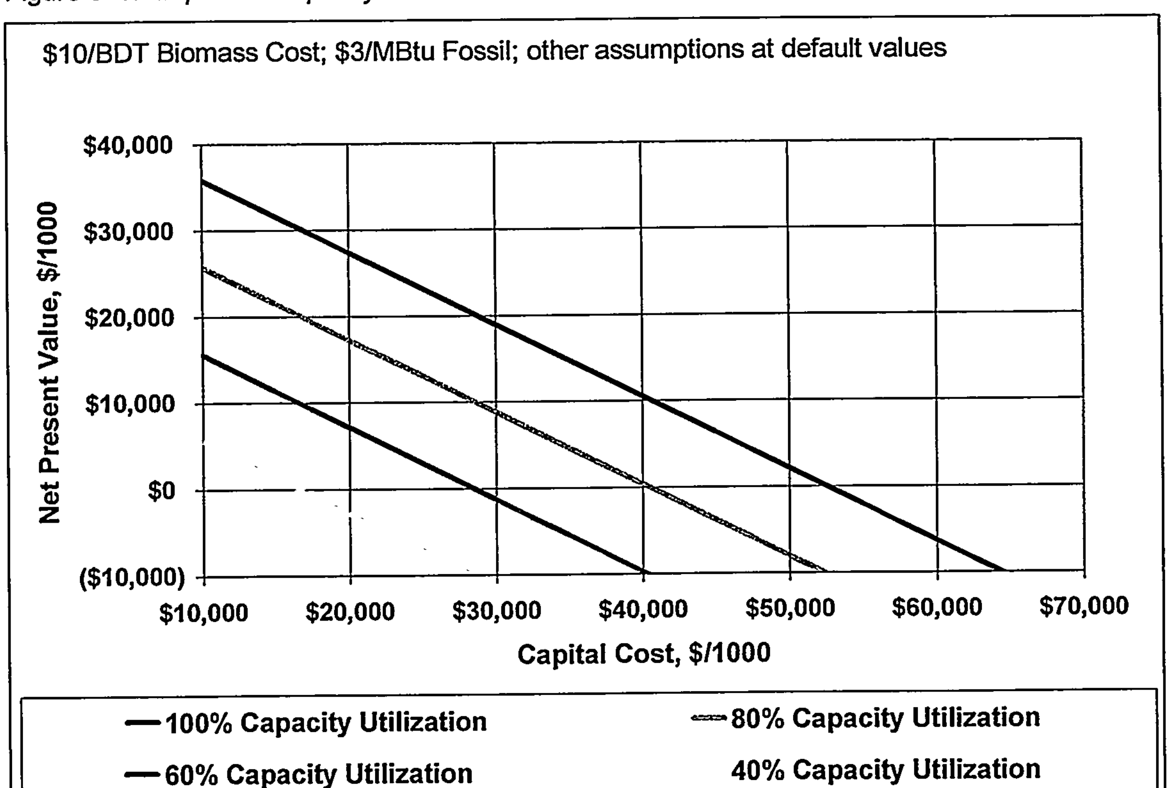


Figure 9–10: Impact of Capacity Utilization on Net Present Value

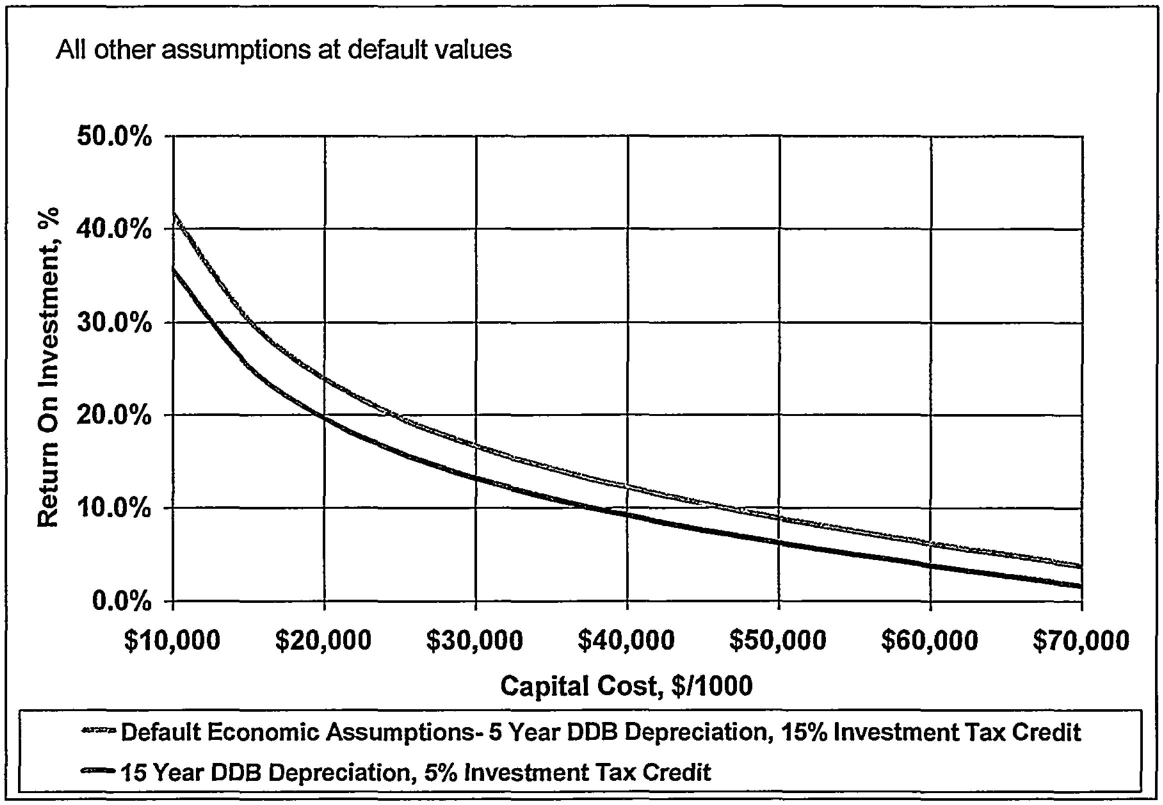


Figure 9–11: Impact of Preferential Tax Treatment on Return on Investment

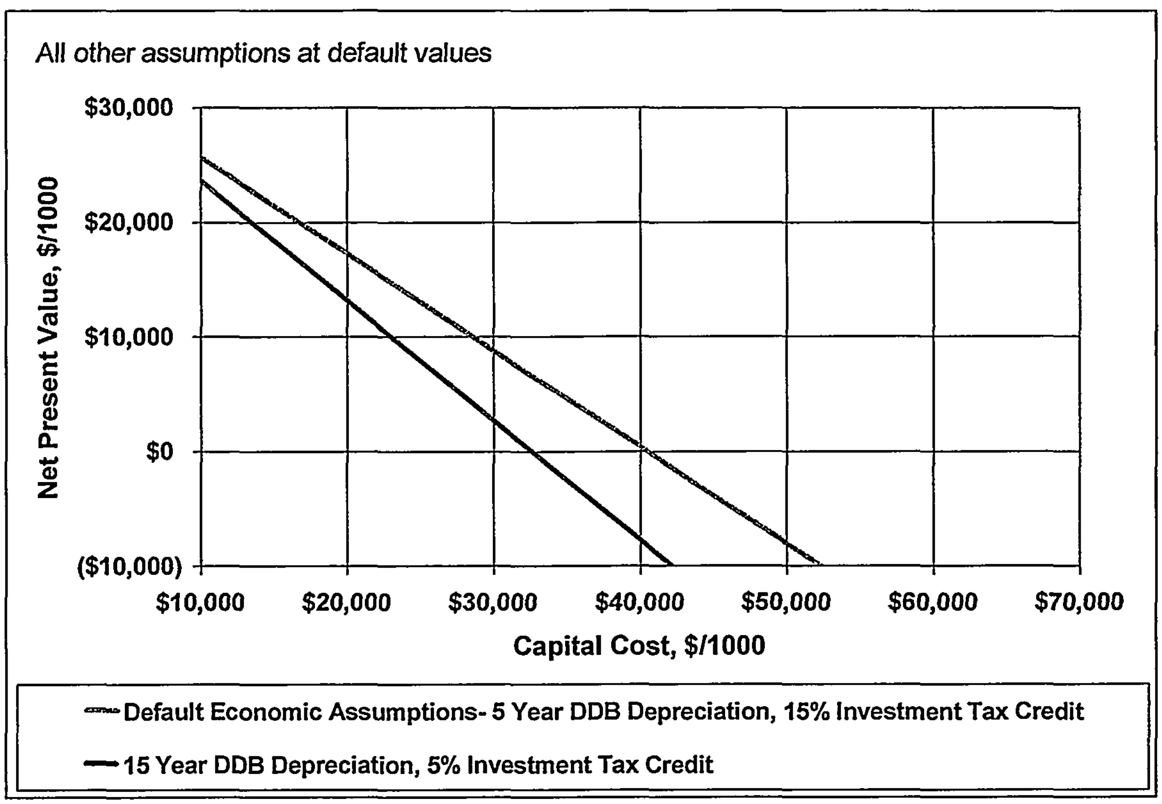


Figure 9–12: Impact of Preferential Tax Treatment on Net Present Value

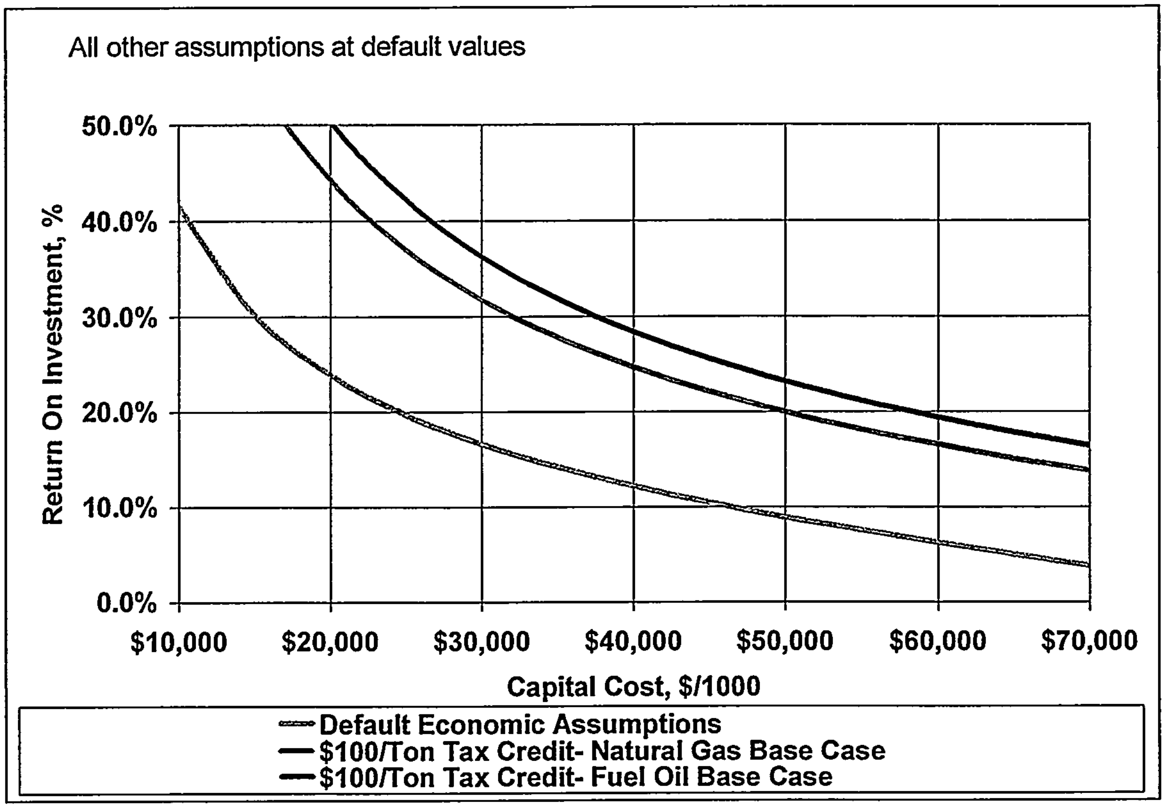


Figure 9–13: Impact of Tax Credits for Avoided Carbon Emissions on Return on Investment

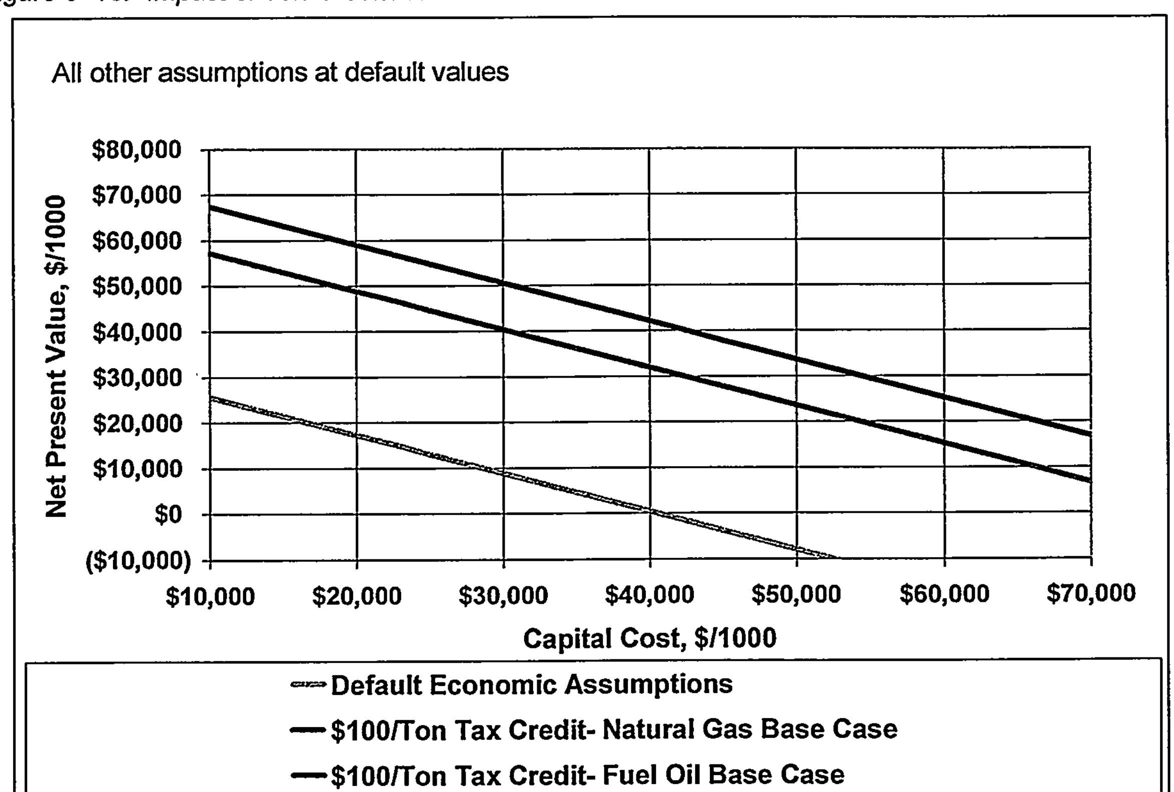


Figure 9–14: Impact of Tax Credits for Avoided Carbon Emisisons on Net Present Value

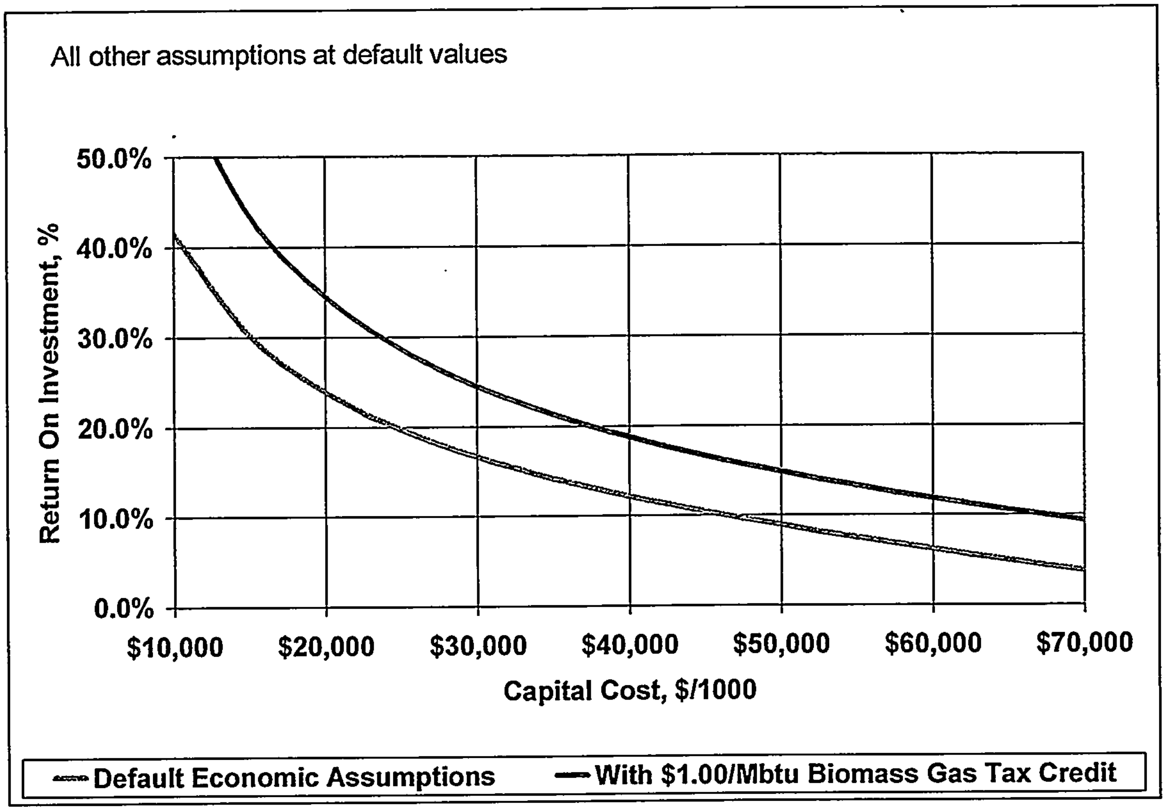


Figure 9–15: Impact of Fuel Gas Tax Credit on Return on Investment

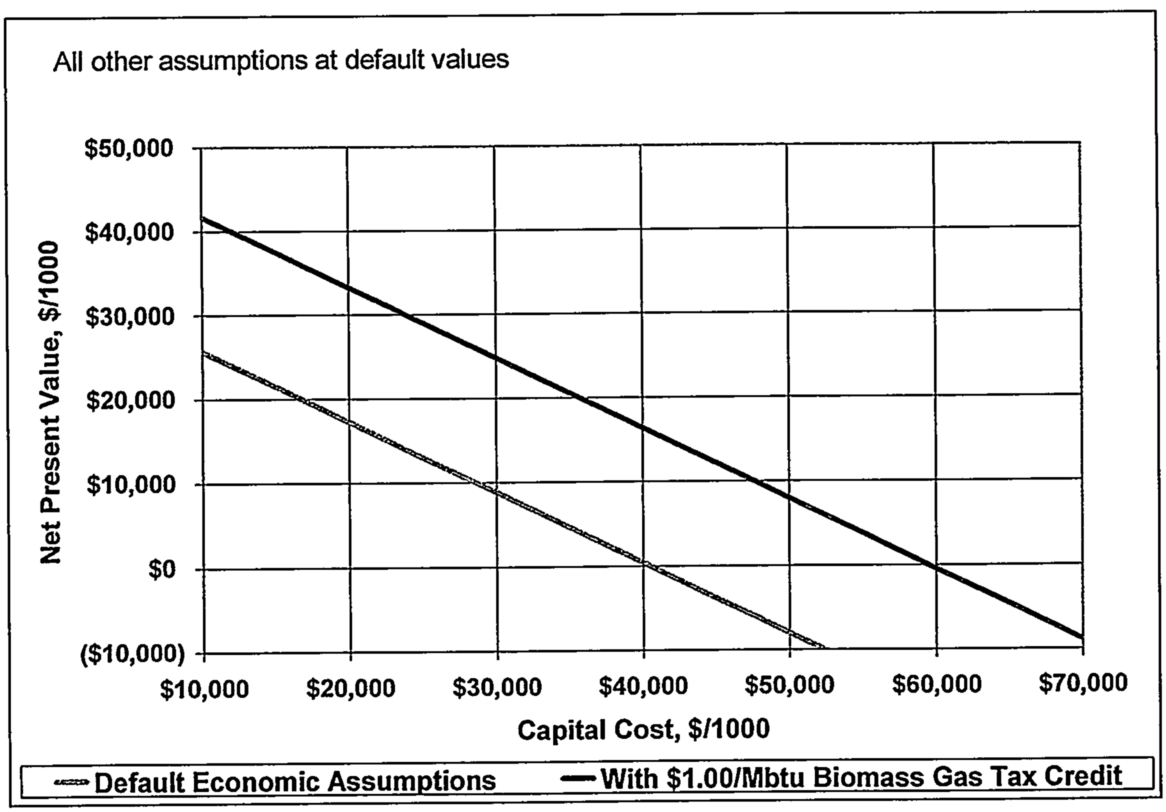


Figure 9–16: Impact of Fuel Gas Tax Credit on Net Present Value

As in the New Bern cases, a range of ROI "hurdle rate" values from 12% to 19% has been defined to represent the minimum threshold required for project economic viability. In Table 9–3, below, supportable capital for the generic LIVG project is displayed as a function of biomass and fossil fuel prices.

	Fossil Fuel, $3.00/MBtu		Fossil Fuel, $4.00/MBtu		Fossil Fuel, $5.00/MBtu	
Biomass Fuel Cost, $/BDT	Supportable Capital @ 19% ROI	Supportable Capital @ 12% ROI	Supportable Capital @ 19% ROI	Supportable Capital @ 12% ROI	Supportable Capital @ 19% ROI	Supportable Capital @ 12% ROI
$0/BDT	$34.2M	$52.6M	$48.8M	$74.7M	$63.3M	$96.4M
$10/BDT	$26.1M	$40.2M	$40.6M	$62.5M	$55.1M	$84.5M
$20/BDT	$17.9M	$28.2M	$32.4M	$50.4M	$46.9M	$72.4M
$30/BDT	$9.7M	$16.1M	$24.2M	$38.1M	$38.7M	$60.3M

Table 9–3: Supportable Capital Summary

Generic system capital ($49.9M) is supportable in unshaded portion of table. As expected, greater spread in fossil vs. biomass fuel pricing increases the supportable investment in the technology. Similarly, decreasing investor expectations with regard to return on investment also increase the level of supportable investment.

Figures 9–9 and 9–10 address the impact of capacity utilization. In the default case, the project operates at 80% of design rating for a 355 day annual operating schedule. In all cases, it is assumed that fossil fuel is fired 4% of the time due to gasifier island downtime. As is typical of any solid fuel utilization technology, this process lends itself to high-utilization or base loaded applications in order to justify the capital expenditure.

Figures 9–11 and 9–12 show the impact of changing project depreciation schedule from five year DDB to fifteen year DDB and removing the 15% tax credit assumed to be available for biomass projects. As seen in Figure 9–11, these measures increase the supportable investment in the generic project by $6 million to $9 million.

The impact of potential renewables or carbon emission-related public policy incentives to encourage biomass utilization is displayed in Figures 9–11 through 9–16. In Figures 9–11 and 9–13, it is seen that—given the default economic assumptions—these policy incentives bring project returns into the threshold range at the $50 million capital investment estimated to be necessary for the generic case. Table 9–4 displays public policy incentive values needed , given the default economic assumptions, to bring project viability (as measured by ROI) into an acceptable range.

PARAMETER	Generic Plant "Nth Plant" Capital Cost = ~$50.0M	
	Value for 12% ROI	Value for 19% ROI
Fuel gas tax credit, $/MBtu (based on higher heating value of product gas)	$0.49	$1.77
Tax credit for avoided atmospheric carbon emissions, $/ton avoided carbon emission **Natural Gas as Base Case Fuel**	$24.87	$89.85
Income from taxable emission credit for avoided atmospheric carbon emissions, $/ton avoided carbon emission **Natural Gas as Base Case Fuel**	$40.11	$144.91
Tax credit for avoided atmospheric carbon emissions, $/ton avoided carbon emission **#6 Fuel Oil as Base Case Fuel**	$18.85	$68.08
Emission credit (taxable) for avoided atmospheric carbon emissions, $/ton avoided carbon emission **#6 Fuel Oil as Base Case Fuel**	$30.40	$109.80
Capital Cost Support (One Time Payment), $	$9.5M	$23.9M

Table 9–4: Level of Public Policy Incentive to Reach Threshold Rate of Return

As can be seen in the table, the magnitude size of public policy-based incentives are lower for the generic case than for the analogous incentives in the New Bern-specific case (see Table 8–4). This is due mainly to two differences between the generic and the New Bern cases: 1) the wider spread between fossil fuel and biomass fuel pricing in the generic case, and 2) the lower capital cost inherent in defining the generic case. Also noted above, the magnitude of carbon-based incentives will have to be larger in cases where natural gas is displaced due to the lower carbon emissions from natural gas firing.

9.5 Conclusions

In the absence of public policy incentives, the generic LIVG project looks economically attractive for combinations of high avoided fossil fuel price and low biomass fuel price as shown in Table 9–3. Given the default economic assumptions used in this analysis, which includes an avoided fossil fuel price of $3.00/MBtu, investment in the generic LIVG project is warranted only at very low market values for biomass fuels. Investment would only be warranted at the low end of the defined threshold range of project ROI. This range of return would likely be attractive to investors only for well proven process technologies used where future revenue streams are well understood (such as in the independent power production projects being developed today). Given that the generic project represents an "Nth Plant" situation, additional incentives —such as significant "buy down" of capital cost—will most likely be necessary for early applications of the technology.

Public policy incentives typical of those used today to encourage biomass use (e.g., accelerated depreciation schedules, modest investment tax credits) have a significant impact on the economic performance of projects such as this one (see Figures 9–11 and 9–12). However, given the default assumptions used here, they would not be sufficient to support project implementation except where biomass fuels were free or where a disposal problem exists.

Public policy incentives which give economic recognition to the value of renewable fuels or to the avoidance of atmospheric carbon emissions are likely to play a key role in the viability of technologies such as the LIVG process. This is certainly true in the current technology development phase. Whether it is also true given commercially proven process technologies depends on the future direction of fossil fuel prices.

Section 10

Overall Conclusions

10.0 Overall Conclusions

Gasification combined cycle continues to represent an important defining technology area for the forest products industry. The "Forest Products Gasification Initiative", organized under the Industry's Agenda 2020 technology vision and supported by the DOE "Industries of the Future" program, is well positioned to guide these technologies to commercial success within a five- to ten-year time frame given supportive federal budgets and public policy. Commercial success will result in significant environmental and renewable energy goals that are shared by the Industry and the Nation.

The Battelle/FERCO LIVG technology, which is the technology of choice for the application reported here, remains of high interest due to characteristics that make it well suited for integration with the infrastructure of a pulp production facility. The capital cost, operating economics and long-term demonstration of this technology are a key input to future economically sustainable projects and must be verified by the 200 BDT/day demonstration facility currently operating in Burlington, Vermont.

The New Bern application that was the initial objective of this project is not currently economically viable and will not be implemented at this time due to several changes at and around the mill which have occurred since the inception of the project in 1995.

The analysis shows that for this technology, and likely other gasification technologies as well, the first few installations will require unique circumstances, or supportive public policies, or both to attract host sites and investors.

Examples of supportive public policies are:

- Tax credits for biomass gas production ($0.50/MBtu or higher)
- Tax credits for avoided atmospheric carbon emissions ($25/ton avoided carbon or higher)
- Capital cost support for the first 2–3 plants (50% or greater)
- Flexibility of EPA rules and permitting procedures to allow for time to implement and time to develop alternative solutions in the event of technology failure

Examples of unique circumstances are:

- High non-recovery fuel cost ($3.00/MBtu or greater)
- High electric power value ($0.05/kWh or greater
- Low wood residual cost ($10/BDT or lower)
- Disposal costs or issues
- Aging power infrastructure that requires replacement or major relifing costs

These policy and circumstance areas are not mutually exclusive, nor will one area alone justify a project. It is likely that a number (but not all) of the above will have to work together to make the first few projects economically sustainable and interesting enough to justify the risk and attract the investors.

Weyerhaeuser continues to support the development and commercialization of gasification combined cycle technologies in general, and the Battelle/FERCO LIVG technology specifically, in order that they may become viable commercial choices for Weyerhaeuser and the Industry within the current decade.