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OR-0377-8

DOE/OR/03054-30
(DE84013522)

STEAM/FUEL SYSTEM OPTIMIZATION REPORT. 6,000-tpd SRC-I DEMONSTRATION PLANT

By
T. D. Vakil

Work Performed Under Contract No. AC05-78OR03054

International Coal Refining Company
Allentown, Pennsylvania

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Price: Printed Copy A05
Microfiche A01

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Distribution Category UC-89

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ABSTRACT

This report describes how the design for the steam and fuel system of the SRC-I Demonstration Plant was optimized to increase overall efficiency, reliability, and flexibility. The system was optimized primarily for the most likely modes of plant operation; however, it is operable under all anticipated modes of operation.

EXECUTIVE SUMMARY

The design and configuration of the steam and fuel system for the 6,000-ton-per-day (tpd) SRC-I Demonstration Plant have been optimized, based on requirements for each area of the plant that were detailed in Area Baseline Designs of December 1982. The system was optimized primarily for the two most likely modes of plant operation, that is, when the expanded-bed hydrocracker (EBH) is operating at either high or low conversion, with all other units operating. However, the design, as such, is also operable under four other anticipated operating modes. The plant is self-sufficient in fuel except when the coker/calciner unit is not operating; then the required fuel oil import ranges from 80 to 125 MM Btu/hr, lower heating value (LHV). The system affords stable operation under varying fuel gas availability and is reliable, flexible, and efficient. The optimization was based on maximizing overall efficiency of the steam system.

The system was optimized to operate at five different steam-pressure levels, which are justifiable based on the plant's steam requirements for process, heat duty, and power. All identified critical equipment drives will be run by steam turbines.

Also part of the optimization was elimination of the steam evaporator in the wastewater treatment area. This minimized the impact on the steam system of operating in either the discharge or zero-discharge mode; the steam system remains essentially the same for either mode.

Any further optimization efforts should be based on overall cost-effectiveness.

PROCESS DESCRIPTION

The SRC-I Demonstration Plant is designed to process 6,000 tpd of high-sulfur coal to produce liquid and solid fuels. The plant includes numerous processing steps, support processes, and utility systems. This report describes the design and optimization work performed by ICRC for the plant's steam and fuel system.

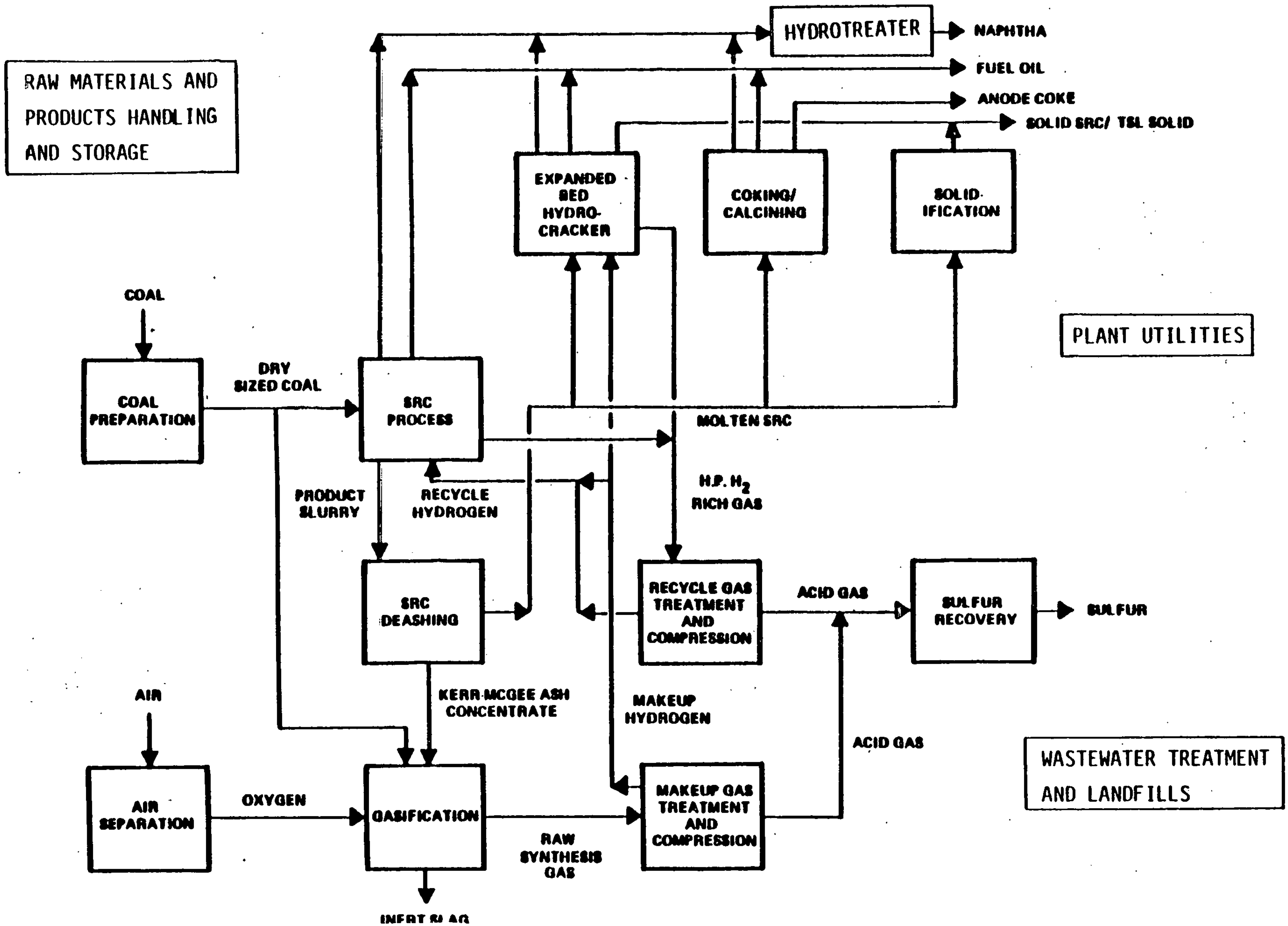
Figure 1 is a demonstration plant schematic showing major process units. Coal preparation comprises receiving, unloading, conveying, storing, reclaiming, drying, and pulverizing the coal used as feed for the process units. The SRC process unit involves slurrying, dissolution, hydrogenation, and desulfurization of coal, and separation of products. SRC deashing separates SRC/ash slurry into liquid SRC and ash using a deashing solvent. The separated ash, along with unconverted coal, is mixed with supplemental coal and sent to the gasification area. This area converts ash into inert slag and produces makeup hydrogen required for the SRC, expanded-bed hydrocracker (EBH), and naphtha hydrotreater (NHT) areas. The air separation unit provides oxygen for the gasification reaction.

The makeup gas treatment area includes shift, Selexol, and methanation units. The recycle gas treatment area includes the hydrogen purification unit (HPU), the diethanolamine unit (DEA), and the liquid petroleum gas (LPG) recovery unit. The sulfur recovery area includes the Beavon sulfur removal unit (BSRU) and the Claus plant.

The combination of SRC production followed by EBH is known as two-stage liquefaction (TSL). The EBH process receives part of the molten SRC and converts it catalytically into naphtha, fuel oil, and low-sulfur SRC solids, called TSL solids. The coker/calciner unit receives part of the molten SRC and converts it to anode coke, fuel oil, and naphtha. The balance of the liquid SRC is solidified to solid SRC fuel.

Main plant products include naphtha, middle distillate, heavy oil, and solid SRC/TSL. The by-products are sulfur and LPG. The plant also produces some light hydrocarbon gases in the SRC, EBH, and coker areas. These gases are cleaned and used within the plant heaters and boilers as fuel gas.

FIGURE 1
DEMONSTRATION PLANT SCHEMATIC



PLANT STEAM/FUEL SYSTEM

The demonstration plant has several heat recovery systems that produce steam at various pressures and temperatures. Numerous plant units require steam/boiler feedwater (BFW)/condensate as process feed streams. Utility steam is required throughout the plant as a heating medium in plant exchangers, jacketed vessels, and steam coils. In addition, some of the plant's critical pumps and compressors are driven by steam. The steam system had to be designed so that it was responsive to plant demands under start-up, shutdown, and normal operating conditions. Moreover, it had to economically and efficiently balance the plant steam production and requirements at various steam-pressure levels. This required a rather complex, integrated design.

Evolution of Design

Area Contractor Estimates. The current steam/fuel system design and configuration evolved from estimates of steam production and of requirements for steam and fuel that were prepared by area contractors. Each area contractor was responsible for process and equipment design of one of eight major process areas that subdivide the SRC-I plant:

Area no.	Contractor	Description
11	The Rust Engineering Co.	Raw materials and products handling and storage
12	Catalytic, Inc.	SRC process, deashing, and solidification
13	The Lummus Company	EBH, coker/calciner
14	Air Products	Air separation unit, HPU
15	The Ralph M. Parsons Co.	Gasification, recycle and makeup gas treatment, compression, and sulfur recovery
16	The Rust Engineering Co.	Utility systems
17	The Rust Engineering Co.	Waste and water treatment
NHT	Stearns-Roger	Naphtha hydrotreatment

The estimates forming the basis of the design were included in Design Baselines for each plant area.

Operating Cases. The design was optimized by considering six major operating cases that were assumed for the plant:

Case 1: All units operating; EBH at high conversion

Case 2: All units operating; EBH at low conversion

Case 3: Coker/calciner down; EBH at high conversion

Case 4: Coker/calciner down; EBH at low conversion

Case 5: EBH down

Case 6: Both coker/calciner and EBH down

Cases 1 and 2, the most likely, were assumed to prevail more than 80% of the time. However, even though the other four cases are less likely, the steam and fuel system had to be designed to be operable under all cases.

Fuel Gas Availability. The SRC-I plant generates fuel gas, LPG, liquid and solid fuels, and sulfur. In designing the plant, ICRC's philosophy was to consume all unsalable fuel and to market all salable fuel. All fuels but the plant-generated fuel gas are salable. Therefore, the plant's numerous heaters and the steam boiler were designed to fire the plant-generated fuel gas.

The fuel gas is generated from two sources:

a. Gasifier-produced residual hydrogen, which is left over after satisfying plant chemical demands

b. Reaction yields of hydrocarbon gases from the SRC, EBH, coker, and NHT areas

The following chart approximates the fuel gas availability from these areas under expected normal yields:

Area	Total fuel gas availability under normal yields from sources a and b above (MM Btu/hr, LHV)	
	EBH at high conv.	EBH at low conv.
SRC	444	444
EBH	283	337
Coker	143	143
NHT	16	17
Plant total	886	941

Out of all plant-generated fuel gas, approximately 10% is extractable as LPG fuel (the C_3-C_5 cut), on a Btu basis. The BSRU area needs constant-Btu fuel equivalent to about 2% of the total plant fuel gas requirements. Also, plant burners require constant-Btu fuel for pilots, equivalent to about 1% of the total requirements. The plant-recovered LPG fuel is considered constant-Btu fuel. Thus, at all times, the plant constant-Btu fuel requirements will be met by extracting, as a minimum, the required amount of LPG for consumption. The fuel system collects plant-generated fuel gas, recovers an appropriate amount of LPG as dictated by the plant fuel balance, and then distributes the residual fuel gas to process heaters and the boiler (in that order).

When the total fuel gas generated exceeds plant requirements, the excess can either be recovered as LPG product or burned in the boiler. The upper limit on LPG recovery is dictated by the maximum recoverable LPG present in the fuel gas. Any excess existing LPG, after recovering the maximum extractable LPG, will remain in the fuel gas and will be fired in the boiler, producing additional steam. Such excess steam is utilized for power recovery using steam turbines. Thus, any unrecoverable excess fuel gas, instead of being flared, is used to generate high-pressure steam.

When the amount of fuel generated does not meet demand, only the LPG needed for constant-Btu fuel and pilots is recovered; the residual fuel gas is distributed first to the plant burners and then to the boiler. The boiler fuel deficiency (cases 3, 4, and 6) is made up by importing fuel oil. In some instances, such as operating cases 5 and 6, when the EBH is down, the plant fuel deficiency is supplied by excess hydrogen available from the gasifiers, which is blended into the plant fuel gas. However, for the six operating cases considered, the plant always produces enough fuel gas (including excess hydrogen fuel) to satisfy process plant fuel requirements (excluding the boiler).

Need for Optimization

The steam system for the SRC-I plant must ensure plant operability under all anticipated operating conditions, including start-up and shutdown. Based on start-up and net operating steam requirements, ICRC realized that the plant must generate high-pressure steam in a boiler. The steam system design had to be optimized to ensure efficient usage of all available steam at the highest possible pressure levels, since this will directly affect the plant's overall thermal efficiency. Optimization was also required to establish overall cost-effective power recovery schemes with due consideration to driving identified critical equipment with steam. Although the steam system configuration had to be optimized for only the most likely cases, operability for the other less likely cases also had to be guaranteed.

Also requiring consideration was the effect of alternative discharge modes (either zero discharge or discharge of wastewater into the Green River) included in the wastewater treatment area design. The zero-discharge mode requires an evaporator, whereas the discharge mode does not. Other process differences within the wastewater treatment area for these alternate modes do not impact the steam system design. Thus, of major concern in optimizing the steam/fuel system design was whether the evaporator was steam-driven or not. This problem is discussed in the next section.

OPTIMIZATION

Design Philosophy

Overall, ICRC optimized the steam and fuel system for the SRC-I plant based on a philosophy that incorporates the following points:

1. All residual plant-generated fuel gas (after LPG extraction) is consumed within the plant. No fuel gas is flared.
2. Steam turbines are employed to use any excess available steam to produce electric power.
3. Any excess available hydrogen from the gasifiers is blended with the plant fuel gas. Any net plant fuel deficiency is supplied by imported fuel oil.
4. At all times, enough LPG is recovered to supply plant constant-Btu and pilot requirements. Any additional LPG recovery as plant product or back-up fuel is dictated by the plant's fuel balance.
5. The plant fuel gas production was estimated by ICRC based on the Area Baseline yield structures. Fuel gas production was estimated for normal, maximum, and minimum yields (Table 1).
6. The plant steam/fuel requirements and production estimates were based on the revised Area Baselines of December 1982 (Table 2 and Attachment A).
7. The steam/fuel system was optimized essentially for the normal operating cases, i.e., cases 1 and 2. The base case efficiency was not sacrificed to "suboptimize" alternative, less likely cases. The optimized design is operable under all anticipated cases.
8. All critical plant equipment identified in the Area Baselines [raw syngas compressor, LPG compressor, EBH reaction area compressor, SRC area pumpressor, high-pressure BFW pumps, and the boiler forced draft (FD) fan] was assumed to be on steam drives.
9. Steam letdown from higher to lower pressure levels was minimized. Where possible, excess available steam at various

pressure levels was routed to steam turbines for power recovery. No attempt was made to match the recovered power level with the power requirements of additional plant equipment that could be put on stream drive.

10. Steam requirements for the raw syngas and LPG compressor steam turbines were supplied by Parsons. Requirements for other steam turbines were based on information received from Elliott Co. (Table 3).
11. Required condensation of excess low-pressure steam prior to the deaerator, as dictated by the deaerator heat balance, was minimized.
12. Heat losses in the steam system piping and associated equipment were assumed to be negligible. This assumption greatly simplified calculations. Even though not strictly correct, its impact on the overall steam system heat balance is judged minimal.

The steam system was optimized by considering factors such as efficiency of steam usage, the optimum number of steam-pressure levels, power recovery using steam turbines, steam system reliability and operability, and type of turbine. These factors are discussed in detail in this section.

Selection of Steam-Pressure Levels

Attachment A lists the steam production and fuel requirements for each area of the SRC-I plant. Based on the pressure data provided by Area Contractors, ICRC selected five different pressure levels for the demonstration plant:

- 900 psig, 850°F superheated
- 450 psig, saturated
- 150 psig, saturated
- 75 psig, saturated
- 27 psig, saturated

900-psig, 850°F Steam Level. The shift unit requires steam at 900 psig, the highest level for the plant. The coker and SRC areas can produce substantial quantities of superheated 900-psig steam. A steam boiler is specified at this level to provide any plant steam deficiencies and to produce additional steam from excess plant fuel gas. Moreover, power recovery is very efficient at this level. Some of the critical equipment is steam-driven at this level on a continuous basis. A boiler producing steam at this level ensures a reliable, continuous supply of steam to critical equipment specified at this and lower steam levels. Any excess steam due to burning excess plant fuel gas is directed to a power-recovery steam turbine specified at this level. Because of its high quality, 900-psig steam is not intended for heat transfer.

450-psig, Saturated Steam Level. The 450-psig saturated steam was chosen primarily for power recovery. The pressure is high enough to allow efficient power recovery and can be used to drive the remainder of the steam-driven critical equipment. A substantial amount of 450-psig steam can be produced in Catalytic's and Parsons' areas. Because of its high quality, use of this steam for heat transfer should be minimized.

150-psig, Saturated Steam Level. About 33% of the total steam required as a heating medium in the plant's heat exchangers is at the 150-psig level. Also, the Catalytic, Lummus, and Parsons areas need medium-pressure steam for process use. The Lummus and Parsons areas can produce steam at this pressure level.

75-psig, Saturated Steam Level. A steam-pressure level of 75 psig was chosen based on sizable production of such low-pressure steam in the Catalytic and Parsons areas. About 56% of the total steam required for heating in plant exchangers is at 75 psig. Also, Catalytic, Lummus, and Parsons areas need such steam for process use.

27-psig, Saturated Steam Level. The 27-psig steam level was chosen primarily to accommodate the deaerator's low-pressure steam requirements. The GKT gasifier produces enough 27-psig saturated jacket steam for the deaerator. Also, 10% of the total steam needed as a heating medium in plant exchangers is at this level.

Other Levels Considered. Some variations in the steam pressure levels were considered. To make available better-quality steam for power recovery, 650-psig steam was considered for the 450-psig level. The GKT area can upgrade its 450-psig steam production to 650 psig at extra cost. However, the benefits of slightly higher power recovery compared to increased capital costs were judged marginal. During a more definitive design phase in the future, a detailed trade-off study should be performed.

Dropping either the 150- or 75-psig level was also considered, as was its alternative--combining the two into one intermediate level. However, some area contractors specifically required the saturated 150-psig steam temperature to ensure sound engineering design of certain equipment, and other area contractors were unable to produce steam at 150 psig in lieu of 75 psig. Furthermore, because 89% of the total steam duty for the plant's heat exchangers is at these two levels, such factors as the economics of heat exchanger sizes, pressure ratings, and LMTD's would play a major role in choosing appropriate steam levels for individual exchangers. Thus, ICRC opted to maintain both levels in the design.

Boiler Feedwater (BFW) and Steam Condensate Headers. BFW is available to each area at two pressures, 1,110 and 220 psig, based on the plant's requirements for steam production. Equipment generating steam at 450 psig and above uses 1,100-psig BFW; 150-psig and lower pressure steam is generated using 220-psig BFW. Supplying BFW at more than two pressure levels is uneconomical, because any horsepower savings by doing so would not justify incorporating additional BFW supply headers.

One common condensate return header will collect steam system condensate from various areas. This condensate is sent to the deaerator after "polishing" treatment and then recycled to the process plant as part of the BFW. Steam system blowdown is collected in individual areas and routed to the cooling water return header.

Need for Turbine Drives

The demonstration plant is a fairly large coal refinery, having complex, interrelated process areas, some of which are not proven on a commercial scale. Because individual process areas are highly interdependent, minimizing critical equipment failures, and thus avoiding possible shutdown of the plant, is desirable. Critical equipment is that equipment which, when not operating, forces the plant to shut down. Examples of such equipment, in order of priority, are the raw syngas compressor, high-pressure BFW pumps, boiler forced-draft fans, the SRC area pumpressor, the EBH reaction area compressor, etc. If such critical equipment were driven by electricity, a power outage would cause the plant to shut down. This can be avoided, at least for short-term power outages, by driving such equipment with power supplied reliably, constantly, and continuously by steam turbines. Thus, the plant's critical equipment will be steam-driven, using boiler steam, which is considered a reliable source.

A second set of steam turbines is specified in the plant steam system for power recovery. These turbines are incorporated primarily to improve the plant's thermal efficiency by most efficiently using any available excess steam for power recovery. Unlike the critical equipment turbines, these turbines are not essential for the overall integrity of plant operation. If need be, they can be shut off without shutting down the plant. Also, this category of turbines would probably see varying steam flow because of fluctuating amounts of fuel gas available.

Reliability and Operating Flexibility

For proper plant operation, a reliable steam/fuel system that is flexible enough to permit smooth transition from one of the six operating cases (discussed previously) to another is essential. The system must be able to respond to changes in steam/fuel demands and to adjust to expected variations in the amount of fuel gas generated. The fuel gas will vary primarily because of two factors: changes in operating modes and inherently uncertain fuel gas yields from process areas.

An example of the first factor is when the coker unit is shut down. When the coker is not operating, the plant loses (1) significant amounts of 900-psig steam that is normally produced in this area and (2) net fuel gas generation. Thus, the plant not only loses a fuel source, but it has to produce additional steam to make up the deficit caused by the loss of high-pressure steam. Under normal yield conditions, the plant is fuel deficient when the coker is down, requiring fuel oil import.

Table 1 lists normal fuel gas yields for the plant under the six operating cases (step process changes). From the table, the normal yield changes relative to case 1 can be summarized as follows:

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
% change in fuel gas generation	0	+6	-16	-10	-2	-18

Plant fuel balances show surplus fuel for cases 1, 2, and 5. However, cases 3, 4, and 6 are fuel deficient and require fuel oil import to satisfy plant steam/fuel demands.

The second factor responsible for fuel gas variability is the inherent uncertainty in determining the yield structures for reaction areas, i.e., in determining the extent that reactants are chemically converted to hydrocarbon gases in the SRC, EBH, coker, and NHT areas. The yield structures for these areas are derived from pilot plant data; the uncertainties exist because of scale-up and other assumptions. Table 1 provides normal, maximum, and minimum gas yields for the plant under the six operating cases. The yield variability compared to normal can be summarized as follows:

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Maximum	+13%	+12%	+16%	+15%	+13%	+17%
Normal	0%	0%	0%	0%	0%	0%
Minimum	-4%	-4%	-2%	-2%	-4%	-2%

Based on normal plant yields, the plant has a surplus of fuel in cases 1, 2, and 5, and a deficit of fuel in cases 3, 4, and 6. The expected variation in fuel gas yields for each case is favorable--the probability of having lower than normal fuel yields is quite low compared to having higher than normal yields. If yields do fall below normal, fuel oil can be imported to make up the difference. However, if yields are higher than normal, the steam system must be able to use the additional fuel in the boiler to make excess steam and generate power.

The 900-psig steam level is the controlling steam level. A boiler is specified at this level, since any deficiency at this and any lower levels can be most reliably and continuously supplied by boiler-generated steam. Steam at 900 psig, the highest steam pressure in the plant, is most efficient for power recovery. For these reasons, some of the plant's critical equipment is driven using 900-psig steam. A power recovery turbine is specified at this level. The rest of the plant's critical equipment is driven by 450-psig steam rather than 900-psig steam for two reasons:

(1) The plant has significant amounts of net surplus 450-psig steam

(2) Turbine application for low horsepower (less than 10,000) recovery using 900-psig superheated steam is uneconomical.

Steam at pressures below 450 psig is not as efficient for power recovery. Moreover, if the excess 450-psig steam used to drive critical turbines is not available due to an upset condition, the boiler can provide backup steam. Although the boiler steam pressure would have to be reduced to 450 psig, the supply is reliable.

Vendor Information on Turbine Drives

A preliminary review of the steam system indicated that power recovery turbines could be used in addition to the critical equipment turbines. Since the plant has five different steam levels at which turbines can be employed, and since turbines can be categorized as "back-pressured" or "condensing," numerous alternative combinations were possible.[1] Turbine design information, including cost, efficiency, and applications, was needed to evaluate alternative configurations. Thus, discussions were held with several turbine vendors to improve ICRC's understanding of turbine applications, and to obtain necessary design data.

Design data for several turbines applicable to the plant steam system that were obtained from turbine vendors are listed in Table 3. No firm cost data for these turbines were available; preliminary cost

[1]In addition to the standard "condensing" or "back-pressured" turbines, several other types are available, including (1) extraction turbines that can supply steam at some constant pressure between the turbine inlet (throttle) and exhaust; (2) induction turbines that accept steam at two or more different pressure levels; and (3) combined extraction/ induction turbines, which must be specially designed on an individual basis.

estimates received for selected turbines varied appreciably from vendor to vendor. ICRC believes that the cost data were not firm enough to merit inclusion in these optimization efforts. Because time constraints prevented further investigation of the turbine costs, the current steam system optimization was carried out based on optimizing only the overall efficiency of the system. However, the final design should be dictated by an overall cost-effective optimization, i.e., optimization that is based on equipment costs as well as efficiency.

Turbine vendors have indicated that back-pressured rather than condensing turbines are more cost-effective for low-horsepower turbines (less than 1,000 bhp), primarily because of the large turbine exhaust sections needed for the condensing type. For example, a condensing turbine would need a 36-in. exhaust, compared to 10-in. exhaust for a back-pressured turbine of equal horsepower.

According to the vendors' information, limited casing sizes are available for condensing turbines producing steam above 800 psig--the minimum casing size is for 10,000 bhp. Hence, specifying high-pressure condensing turbines for low brake-horsepower equipment, although very efficient, is not cost-effective, since the casing would have to be oversized. Off-the-shelf turbines with standard metallurgy are common for pressures of 650 psig and lower, but turbines for pressures above 650 psig would require careful review. Furthermore, some high-pressure (>800 psig), high temperature (>500°F) turbines require special metallurgy. Also, some vendors have indicated that the moisture content in the turbine exhaust can be critical for stable operation as well as turbine life, because of erosion problems. Specifically, one vendor stated an upper limit of 12 to 14% on the exhaust moisture content; contents above 14% would necessitate exotic metallurgy.

Vendors have also indicated that equipment can be "dual-coupled" with steam and electric drives. Primary power would be supplied by the available excess steam via the steam turbine, and the balance would be automatically provided by the electric drive. This type of arrangement is relatively simple and easy to implement, and would be very useful for power recovery turbines using varying or intermittent steam flows.

On the basis of these considerations and turbine design data in Table 3, appropriate turbines were selected for the plant's critical equipment drives and power recovery schemes. Critical equipment turbines were chosen primarily at the higher pressure levels of 900 and 450 psig, because of their efficiency and reliability. The power recovery turbines were employed primarily to use excess available steam at any given steam level, and to supply prevailing steam deficiencies at any given level by steam letdown through turbines, thereby recovering power.

Critical Equipment Turbines. The raw syngas compressor turbine is the most critical equipment that is steam-driven. Two alternative turbine designs were considered for this equipment. Initially, the design consisted of a turbine with a 900-psig, 850°F throttle coupled with a 450-psig saturated induction and 4-in. Hg exhaust. Later, a second design specified a 450-psig, 520°F superheated steam throttle, exhausting to 4 in. Hg. The second design added a new high-pressure LPG compressor turbine, using a 900-psig, 850°F throttle, back-pressured to 450 psig. The exhaust from this LPG turbine was combined with enough 450-psig saturated steam to compose feed to the revised raw syngas turbine design.

The basic difference between the two designs is that the initial design specified an induction turbine, whereas the revised design calls for a straight condensing turbine. Since the available 900-psig, 850°F steam to this turbine is expected to vary because of fuel gas variability and changes in operating modes, the throttle-to-induction ratios in the initial design would vary. At low throttle-to-induction ratios, the moisture content within the turbine may exceed an indicated upper limit of 12-14%, thereby necessitating exotic metallurgy.

The revised design calls for a combination of LPG and raw syngas turbines. The LPG turbine requires less 900-psig throttle steam than that required for the earlier raw syngas (RSG) turbine design. Thus, the revised LPG/RSG turbine system requires a reduced amount of 900-psig steam flow, flow that the steam system can deliver on a constant basis under normal operating modes. The combined turbine system can now be base-loaded with 900-psig steam. Preliminary indications from turbine vendors suggest that the capital cost differences between two schemes on an equivalent power recovery basis are indistinguishable.

The 725-bhp compressor turbine for the EBH reaction area is specified at 900 psig in the Baseline Design for that area. Based on vendor information, this small service is not cost-effective at such a high steam level. This concern was pointed out in an ICRC memo[2] that recommended usage of the 450-psig steam level. In Area 12, the pumpressor, high-pressure BFW pumps, and boiler F.D. fan turbine drives use 450-psig steam since an excess of steam is available at this level, and the level is efficient for power recovery. In emergencies, the steam boiler can supply these steam requirements.

Power Recovery Turbines. The choice of 450-psig steam for the critical equipment turbines also depended in part on a specific configuration for the power recovery turbines. Numerous alternate configurations for the critical equipment and the power recovery turbines were evaluated for maximum efficiency. The current optimized configuration is judged to yield the best steam system efficiency. However, the configuration may not be optimum on an overall cost-effective basis. Also, the power recovery turbines recover power from excess available steam, which varies from case to case; thus, the level of power recovery will vary. In contrast, the level of power recovery is constant from case to case for the critical equipment turbines. To some extent, the power recovery turbines serve as a flywheel for the steam/fuel system. These turbines can absorb the variability in the steam/fuel system demands and production.

Zero-Discharge and Discharge Modes

The presence of an evaporator in the wastewater treatment area can significantly impact the steam system design. The evaporator is required only for the zero-discharge operating mode. If needed, the evaporator can be either a "steam-type" or "vapor recompression-type." A steam evaporator requires large amounts of 75-psig steam for evaporation, whereas the vapor recompression evaporator consumes only electric power for vaporization. The Utilities and Off-Sites Baseline specifies a steam-type evaporator (zero-discharge mode), requiring 106,000 lb/hr of 75-psig steam on a continuous basis. This steam requirement, if present, can adversely affect the efficiency of the steam system in two

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[2] T. D. Vakil to J. R. Gough, "Steam System Design for Baseline II," 13 August 1982.

ways. First, since this is not a critical service, use of electric drive would be more economical. Second, since the 450-, 150-, and 75-psig steam headers are roughly balanced without this evaporator steam requirement, an equivalent amount of 850-psig steam would have to be let down by either turbines or pressure-reducing valves to make up the deficit that would prevail in the 75-psig header should the evaporator be on-stream. This would significantly reduce efficiency. For these reasons, the evaporator was changed from a steam to a vapor recompression type, requiring no steam. This change, in addition to the above benefits, provides additional steam at 450 psig, since most of the previous back-pressured (450-psig throttle/75-psig back pressure) turbines can now be condensing type, requiring less 450-psig throttle steam. The additional 450-psig steam that is freed up can be used to drive critical equipment turbines at 450 psig.

Although the current Utilities and Off-Sites Baseline specifies a "steam-type" evaporator for the zero-discharge mode, ICRC process engineering has internally decided to change the design to a "vapor recompression" evaporator. Thus, the current steam system design is based on having such an evaporator system. In addition to the benefits discussed above, an important impact of the decision to eliminate evaporator steam requirements is that the steam system design remains unaffected for either zero-discharge or discharge modes.

CURRENT STEAM/FUEL SYSTEM DESIGN

Configuration

The current energy-optimized steam system design consists of:

(a) Five different steam collection/distribution headers, at nominal pressure levels of 900 (superheated, 850°F), 450, 150, 75, and 27 psig
(b) One condensate return header
(c) Two separate BFW distribution headers at 1,100- and 220-psig pressure levels
(d) A steam boiler producing makeup steam at the 900-psig, 850°F level
(e) A deaerator for BFW preparation
(f) Steam turbines for driving the plant's critical equipment, i.e., the raw syngas compressors, the SRC area pumpressor; the EBH reaction area compressor, the high-pressure BFW pumps, and the boiler F.D. fan
(g) Three power recovery turbines
(h) Steam letdown valves connecting each level steam header to the next lower level steam header
(i) A steam condenser for excess 27-psig steam
(j) Pumps and auxiliary equipment

Discussion and Design Data

Based on this optimized steam system design, the following design information has been developed.

Steam system heat-and-material balances were developed for the six operating cases based on the optimized design. In addition, a seventh "maximum" case material balance was developed to aid in line sizing. However, this "maximum" case does not represent an operating case.

The material balances of Attachment B are based on the steam requirements summarized in Attachment A. Attachment A provides a detailed unit-by-unit summary of steam requirements for each area, including normal and maximum requirements. This summary is based on information contained in the Area Baselines of December 1982.

The material balances assume normal yields. Plant operating cases 1 and 2 of Attachment B represent the most likely operating modes; the steam system design is based on optimizing the efficiency for these two cases only. However, as can be seen, the steam system is also operable for the other four modes.

For cases 1 and 2, the 900-, 150-, and 27-psig steam levels are deficient of steam, whereas the 450- and 75-psig levels have a surplus. The deficiency at the 900-psig level is made up by the steam boiler, that at 150 psig is made up by power recovery turbine no. 2, and that at 27 psig is made up by letting down excess 75-psig steam to 27-psig through pressure-reducing valves. Since the required amount of 75-psig steam letdown is relatively small, a power recovery turbine for this purpose was judged uneconomical.

Essentially, all surplus 450-psig steam is used to drive the plant's critical equipment turbines. Surplus 75-psig steam is utilized in power recovery turbine no. 3. Because of excess plant fuel available for case 2, the boiler produces steam in excess of that required. Power recovery turbine no. 1 is specified at the 900-psig level to use this excess steam. This turbine also acts as a flywheel for the steam/fuel system, by absorbing fluctuations in the amounts of excess 900-psig steam that occur because of fuel gas variability, and by stabilizing the steam system.

The amount of fuel gas available has a major impact on the steam system. Based on plant fuel generation and requirements, fuel recovery and distribution diagrams were developed for one maximum and six operating cases. Reference to Attachment C indicates that, under all operating cases considered, the normal fuel gas availability exceeds the process requirements (excluding the boiler). Thus, the boiler always receives residual plant fuel gas. The residual gas to the boiler may be either less than (cases 3, 4, 6, and 7) or more than the boiler requirements (cases 1, 2, and 5). When the fuel gas sent to the boiler is less than required, enough fuel oil is imported to the boiler to offset the difference. When residual gas is in excess of boiler requirements, an equivalent amount of LPG, up to the maximum extractable amount, is recovered as product prior to fuel gas distribution. If an excess still exists after all recoverable LPG is extracted, the gas is burned in the boilers to produce excess 900-psig steam for power recovery using power recovery turbine no. 1.

A special situation arises when the EBH, a major hydrogen consumer, is not operating (cases 5 and 6). Since the plant's overall process H_2 consumption decreases because the EBH requirements are eliminated, there exists a surplus of process hydrogen (from the gasifiers), which is available to the plant as fuel. In such cases, the excess hydrogen is blended with the plant fuel gas for distribution. Operating cases 5 and 6 of Attachments B, C, D, and E reflect this H_2 blending. Note that case 5 assumes all three gasifiers are producing hydrogen at normal rates. However, the steam balance for this case (Attachment B) shows that the boiler receives excess fuel, equivalent to the steam flow rate to power recovery turbine no. 1. It is possible, for this case, to turn down the gasifiers to a point where the excess boiler fuel is eliminated. Table 4 indicates that a gasifier turndown of about 10% may be possible for case 5. However, the attached balances do not consider any such gasifier turndown. A similar situation exists for case 6, but here the coker, a major steam and fuel producer, is also down. Because the plant is fuel-deficient even when the gasifiers are producing hydrogen at normal design rates, no gasifier turndown is possible for case 6.

Table 1 attempts to estimate the fuel gas variability in two ways. First, the variability associated with the defined yield structures for process reaction areas is shown. For each of the six operating cases, normal, maximum, and minimum levels of fuel gas generation are presented. The second variability in fuel gas arises from step changes in the plant's operating modes. The compositions of the fuel gas distributed in each of the six operating cases of Table 1 (under normal yields) are included in Attachment E.

Power Recovery

The power recovery for various operating cases is also summarized in Table 4. The system configuration is optimized to recover maximum power for the most probable operating cases (1 and 2). Since the basis for optimization is maximum system efficiency, the practical aspects of turbine applications are ignored. For example, the level of power recovery for power recovery turbine no. 1 ranges from 277 to 4,572 bhp.

Vendors have indicated that, in practice, a minimum of 10,000-bph recovery is desirable for such 900-psig condensing turbines in order to ensure cost-effectiveness. In addition, it is assumed that the power recovered in such turbines can be used to drive suitable plant equipment, regardless of the level of recovery. No attempt was made to match the level of power recovery with the brake-horsepower of any particular plant equipment. In actual operation, a constant, predetermined level of power recovery from such power recovery turbines is desirable, so that specific users can be identified.

Table 4 indicates that power recovery turbine no. 1 recovers 277 and 3,890 bhp for cases 1 and 2, respectively. Turbine 2 recovers 1,100 bhp for both cases, and turbine 3 recovers 968 and 1,016 bhp, respectively, for the two cases. A glance at Table 5, listing likely additional candidates for steam drive, indicates that the main cooling water circulating pump and the air compressors are rated for 3,500 and 900 bhp, respectively. Obviously, if power recovery turbines 1, 2, and 3 could recover 3,500, 900, and 900 bhp, respectively, on a constant basis, the recovered power could be used to drive one cooling water circulation pump (3,500 bhp) and two air compressors (900 bhp each) on a continuous basis. To achieve this, the steam system must be modified so that:

(a) Turbine 1 recovers 3,500 bhp under all operating cases. Table 4 shows that additional fuel must be imported to produce enough additional steam for turbine 1 to allow the desired 3,500-bhp power recovery for case 1. Case 2 is capable of recovering 3,500 bhp from turbine 1. The other four operating cases are less likely; import of fuel would be required for all except case 5. Flow to this turbine should be constant for all cases.

(b) Turbine 2 recovers a minimum of 900 bhp for all cases. Flow to this turbine should remain constant for all cases. Excess steam, if any, can be let down through valves.

(c) Turbine 3 recovers around 900 bhp for cases 1 and 2. Steam deficiency for case 3 can be supplied by letting down boiler steam, and steam surplus is let down through pressure reduction valves to lower levels.

The above scenario is just one of numerous combinations that can be considered for providing constant power recovery that is compatible with specific equipment needs. Alternatively, equipment can be dual-coupled using steam and electric drives for varying level power recovery turbines.

Any further optimization efforts should be based on overall cost-effectiveness and better-defined applications of the power recovery system.

Equipment

Although the boiler steam production requirements vary from 100,000 to 236,000 lb/hr, the boiler and associated equipment sizing is based on 360,000-lb/hr start-up steam requirements. Excess steam up to 5,000 lb/hr can be handled by a condenser or vented. A condenser was selected because its cost is less than that due to loss of BFW during venting.

Also, various options are available for disposing of excess plant fuel gas:

- Flaring
- Burning excess in boiler, making steam, and recovering power
- Burning excess gas in boiler, making steam, reducing steam pressure through valves, and condensing.

Weighing the cost of equipment with overall plant efficiency dictated the choice of the second option for the plant.

Variation in Fuel Gas Quality

Essentially, ICRC is aware that the variation of fuel is expected in the supply of fuel gas to the boiler and process units. Detailed examination of the equipment has not been carried out in the view of specific design to accept such variation. At the time of equipment purchase, detailed fuel criteria must be provided for the bases of proposal packages for the subject equipment.

Table 1

Estimated Plant Fuel Gas Availability under Normal, Maximum, and Minimum Plant Yields (MM Btu/hr, LHV)

	Case no. and plant operating mode					
	1 All oper., EBH[a] at high conv.	2 All oper., EBH at low conv.	3 C/C[a] down, EBH at high conv.	4 C/C down, EBH at low conv.	5 EBH down	6 Both EBH and C/C down
Normal yields						
Fuel gas[b]	785.48	835.89	644.56	694.99	616.60	475.70
Excess H_2[c]	-	-	-	-	201.52	201.52
LPG[d]	100.76	105.05	100.76	105.05	51.62	51.62
Total	886.24	940.94	745.32	800.04	869.74	728.84
Maximum yields						
Fuel gas[b]	897.75	952.65	757.04	811.93	689.70	546.72
Excess H_2[c]	-	-	-	-	224.35	226.59
LPG[d]	105.05	105.05	105.05	105.05	69.45	69.45
Total	1,002.80	1,057.70	862.09	916.98	983.50	842.76
Minimum yields						
Fuel gas[b]	675.51	725.11	553.70	603.30	470.29	347.34
Excess H_2[c]	89.64	89.64	89.64	89.64	318.81	320.21
LPG[d]	86.40	91.69	86.40	91.69	43.13	43.13
Total	851.55	906.44	729.74	784.63	832.23	710.68

[a] EBH, expanded-bed hydrocracker; C/C, coker/calciner.
[b] This is the residual plant fuel gas after extraction of all available LPG.
[c] This is the residual hydrogen gas available from the Selexol unit.
[d] This is the amount of maximum extractable LPG from plant fuel gas.

Table 2

Plant Fuel Requirements[a]

	Area	Normal operation EBH @ high conv.		Normal operation EBH @ low conv.		Maximum requirements	
		Fuel gas	LPG	Fuel gas	LPG	Fuel gas	LPG
11.	Raw materials & prod. handling & storage	51.4	0.5	51.4	0.5	68.3	0.5
12.	SRC	423.8	4.2	423.8	4.2	518.4	5.2
13.	Coker/calciner	75.2	0.8	75.2	0.8	75.7	0.8
	EBH	31.6	0.3	42.1	0.4	72.4	0.7
14.	ASU	-	-	-	-	-	-
	HPU	6.6	-	6.6	-	6.6	-
15.	Gas systems	-	13.1	-	13.1	-	16.3
16.	Utilities, less boiler	30.2	3.4	30.2	3.4	44.3	3.4
17.	Off sites	-	-	-	-	-	-
TBD	Naphtha hydrotreater	25.1	0.3	25.1	0.3	30.1	0.3
	Subtotal	643.9	22.6	654.40	22.7	815.8	27.2
16.	Boiler firing duty	141.58	2.5	181.49	2.5	311.99	2.5
	Total plant fuel requirements	785.48	25.1	835.89	25.2	1,127.79	29.7

[a]Basis, Revised Baseline documents as of December 1982; units, MM Btu/hr, LHV.

Table 3

Steam Turbine Data

(Items 1-10 Obtained from Elliott Co.;
Items 11-17 Estimated by ICRC)

No.	Steam turbine conditions	hp range	Efficiency (%)	Theoretical steam rate (lb/hp-hr)	Actual steam rate (lb/hp-hr)	% moisture in exhaust[a]	Applications
1.	850 psig, 800°F to 450 psig, 700°F	1,500	70	35.33	50.47[b]	-	LPG compressor
2.	850 psig, 800°F to 4 in. Hg	1,000-5,000	65	5.39	8.29	2.4	Power recovery no. 1
3.	450 psig, 525°F to 4 in. Hg	30,000-35,000	79	6.88	8.71[b]	14.7	Raw syngas compressor
4.	450 psig, sat. to 4 in. Hg	1,000-2,000	70	7.23	10.33	15.3	Pumpressor, high-pressure BFW
5.	450 psig, sat. to 4 in. Hg	500-1,000	60	7.23	12.05	11.9	---
6.	450 psig, sat. to 4 in. Hg	200	55	7.23	13.15	10.2	---
7.	450 psig, sat. to 75 psig	1,000-2,000	65	19.57	30.11	7.2	---
8.	450 psig, sat. to 75 psig	500-1,000	55	19.57	35.58	5.7	---
9.	450 psig, sat. to 75 psig	200	50	19.57	39.14	5	---
10.	75 psig, sat. to 4 in. Hg	0-1,000	60	10.10	16.83	8.0	Power rec. No. 3
11.	850 psig, 800°F to 150 psig, 540°F	500-1,000	65	14.37	22.11	-	Power rec. No. 2
12.	850 psig, 800°F to 75 psig	1,000-2,000	65	11.06	17.02	-	---
13.	850 psig, 800°F to 27 psig	-	65	8.8	13.54	-	---
14.	450 psig, sat. to 150 psig	500-1,000	50	30.65	61.3	3.6	---
15.	450 psig, sat. to 27 psig	200-500	55	14.0	25.45	6.8	---
16.	450 psig, sat. to 27 psig	200	50	14.0	28.0	6.0	Boiler F.D. fan
17.	150 psig, sat. to 75 psig	0-300	50	51.92	103.8	1.5	---

[a] Conditions at turbine exhaust. For condensing turbines (having 4-in. Hg exhaust pressure), the turbine exhaust goes to a condenser for complete condensation of exhaust steam.

[b] Parsons' numbers are used for steam balances of Figures 1-7, Attachment B, instead of these values.

Table 4

Summary of Steam/Fuel System Operation[a]

Case no.	Description	MM Btu/hr of LPG export or fuel oil import	Steam system power recovery (bhp)			Total bhp recovered
			Turbine 1	Turbine 2	Turbine 3	
1	Normal yields/normal steam All units up, EBH @ high conv.	75.66	277	1,100	968	2,345
2	Normal yields/normal steam All units up, EBH @ low conv.	79.85	3,890	1,100	1,016	6,006
3	Normal yields/normal steam Coker/calciner down, EBH @ high conv.	(121.39)	-	891	814	1,705
4	Normal yields/normal steam Coker/calciner down, EBH @ low conv.	(79.66)	-	972	892	1,864
5[b]	Normal yields/normal steam EBH down	26.82	4,572	1,908	1,700	8,180
6	Normal yields/normal steam EBH and coker/calciner down	(125.38)	-	1,787	1,657	3,444
7	Normal yields/maximum steam All units up, EBH @ low conv.	(217.55)	-	6,016	-	6,016

[a] Normal yields mean normal plant gas yields. Normal steam means normal plant steam/fuel requirements. Maximum steam means maximum plant steam/fuel requirements.

[b] All three gasifiers operating at normal rates is assumed. However, it is possible to balance plant fuel requirements by operating the gas systems at an estimated reduced operating rate of 85-90%.

Table 5

Possible Applications for Power Recovery Turbines 1, 2, and 3

Equipment no.	Description	Capacity per unit
P-16603 A-C	Main cooling water (C.T. #1) supply pumps discharging at 97.7 psig, 108°F. Two operating, one spare	3,500 hp, 700 rpm, 221 tdh, 50,000-gpm flow
P-16612 A-C	ASU cooling water (C.T. #2) supply pumps, discharging at 97.7 psig, 108°F. Two operating, one spare	700 hp, 1,200 rpm, 221 tdh, 9,250-gpm flow
C-16701 A-C	Air compressors, discharging at 110 psig. Two operating under normal demand	900 hp, 1,800 rpm, 4,000 icfm at 90°F.

ATTACHMENT A

Baseline II

Area Steam/Fuel Requirements
Normal and Maximum

Legend: All numbers except for fuel are in lb/hr

k/o = Knockout

B/D = Blowdown

HP = High-pressure BFW

LP = Low-pressure BFW

CONS = Consumed within the process area; this portion is not recovered as condensate.

COND = Condensed within the process area; this portion is recovered and returned to Rust Area as condensate

A broken line means that this stream is diverted to k/o pot.

Summary Table at the Top of Each Page

Numbers in parenthesis mean flow out of the unit

Numbers without parenthesis mean flow into the unit

REV.	
AREA	11
BASIS	NORMAL BASELINE II
DATE	12/3/82
BY	TDV

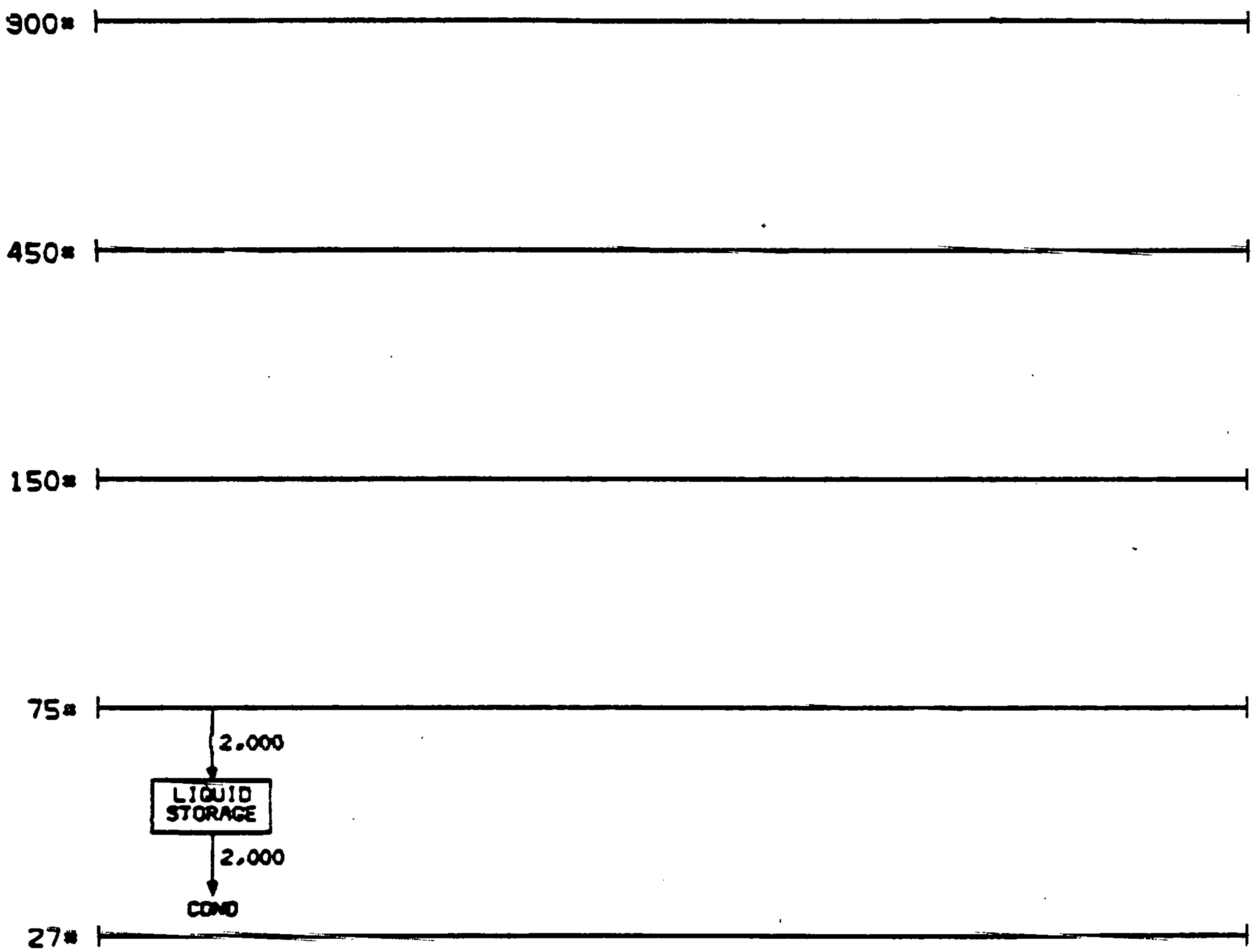
STEAM REQUIREMENTS SUMMARY

HP BFW	-	-	75#, SAT	- 2,000
LP BFW	-	-	27#, SAT	- -
900#, 850°F	-	-	BLOWDOWN	- -
900#, SAT	-	-	CONSUMED	- -
450#, SAT	-	-	CONDENSED	- (2,000)
150#, SAT	-	-	TOTAL	0

FUEL REQ'D
(MM BTU/HR), LHV

GAS = 51.4

LPG = 0.5



F30189

REV. 1 1/10/82

AREA 12

BASIS NORMAL BASELINE II

DATE 12/15/82

BY TDV

STEAM REQUIREMENTS SUMMARY

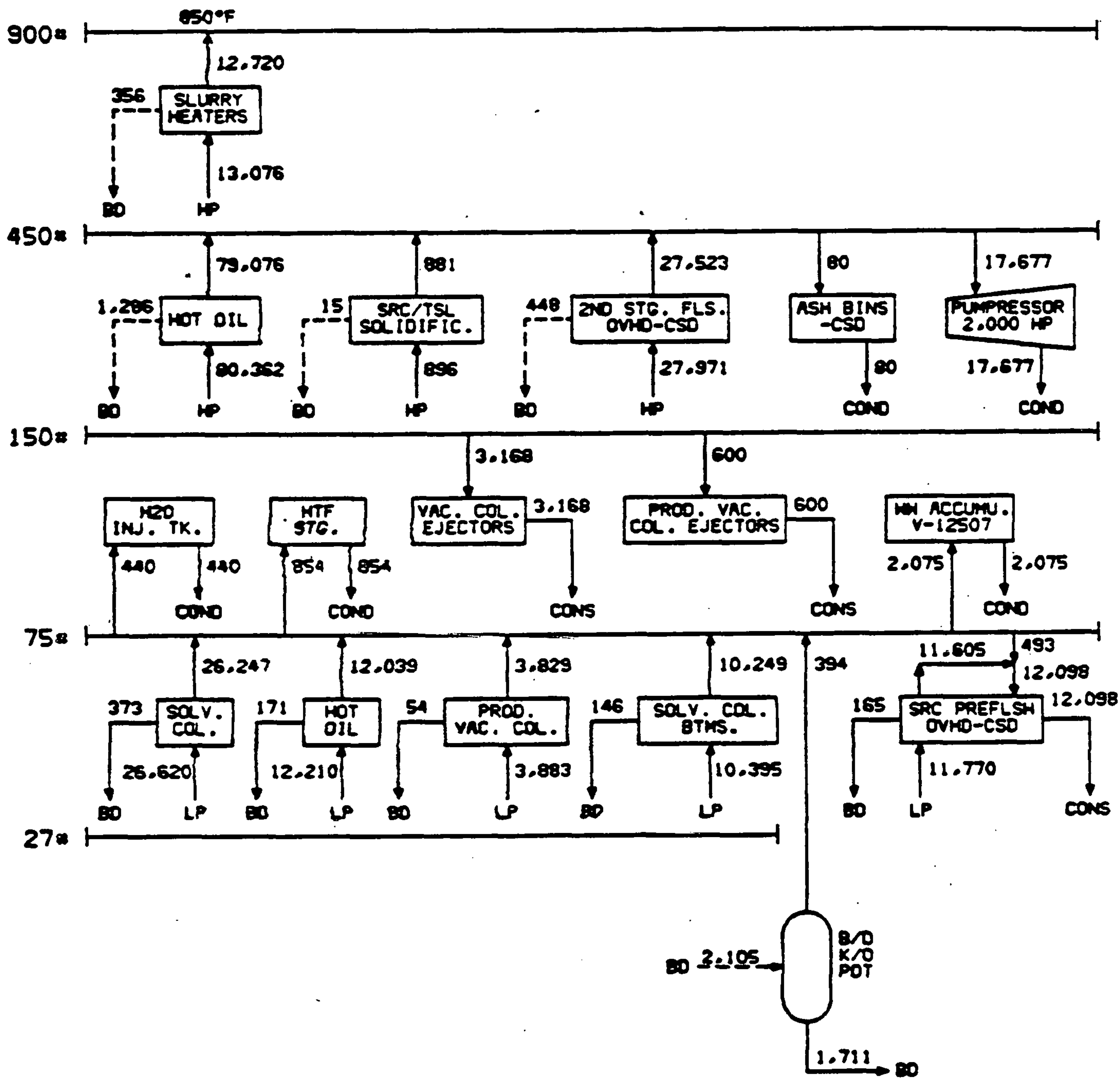
HP BFW	-122,305	75#,SAT	-(48,896)
LP BFW	- 64,878	27#,SAT	- -
900#,850°F	-(12,720)	BLOWDOWN	-(2,620)
900#,SAT	- -	CONSUMED	-(15,866)
450#,SAT	-(89,723)	CONDENSED	-(21,126)
150#,SAT	- 3,768	TOTAL	0

FUEL REQ'D

(MM BTU/HR),LHV

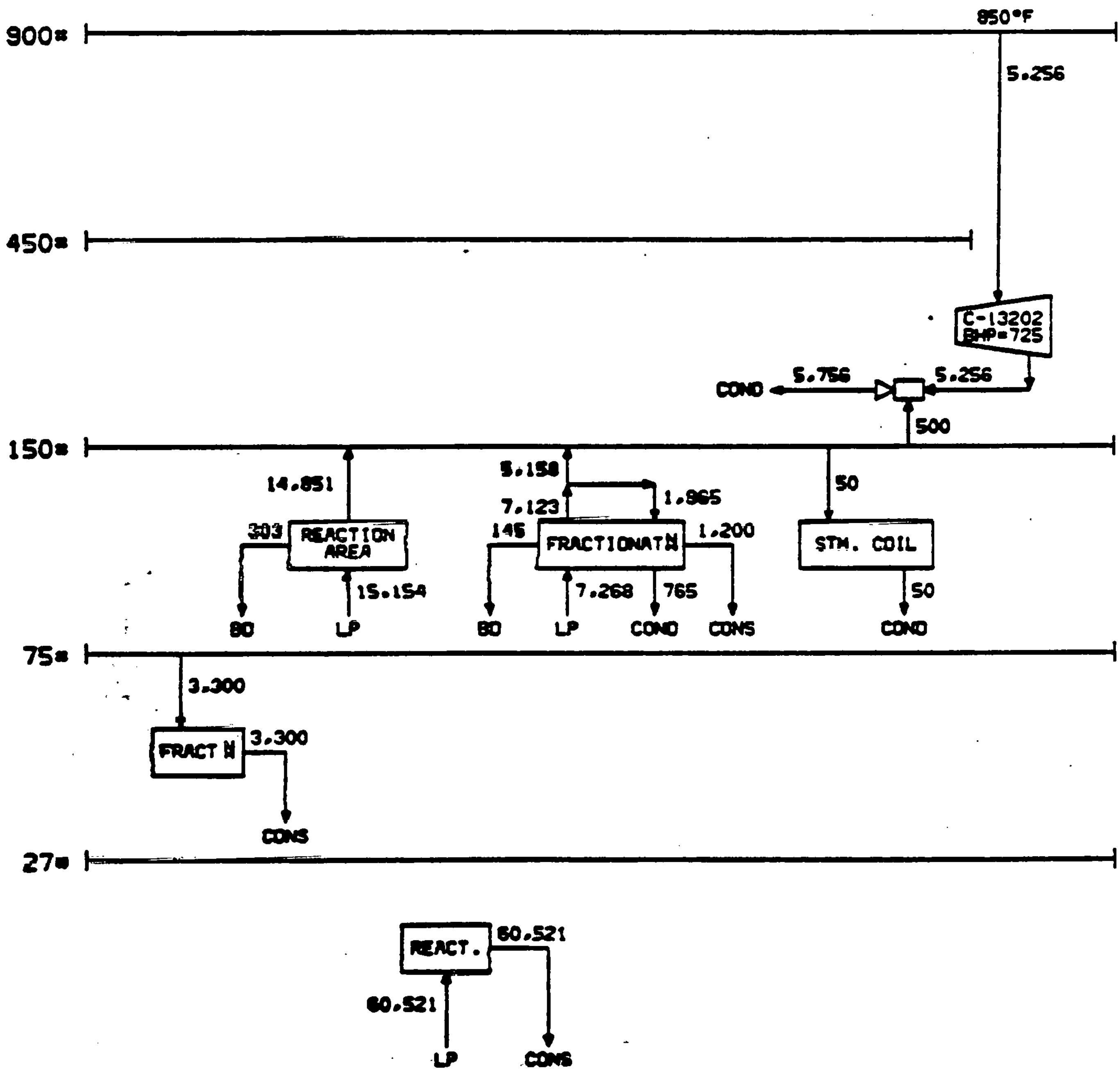
GAS = 423.8

LPG = 4.2



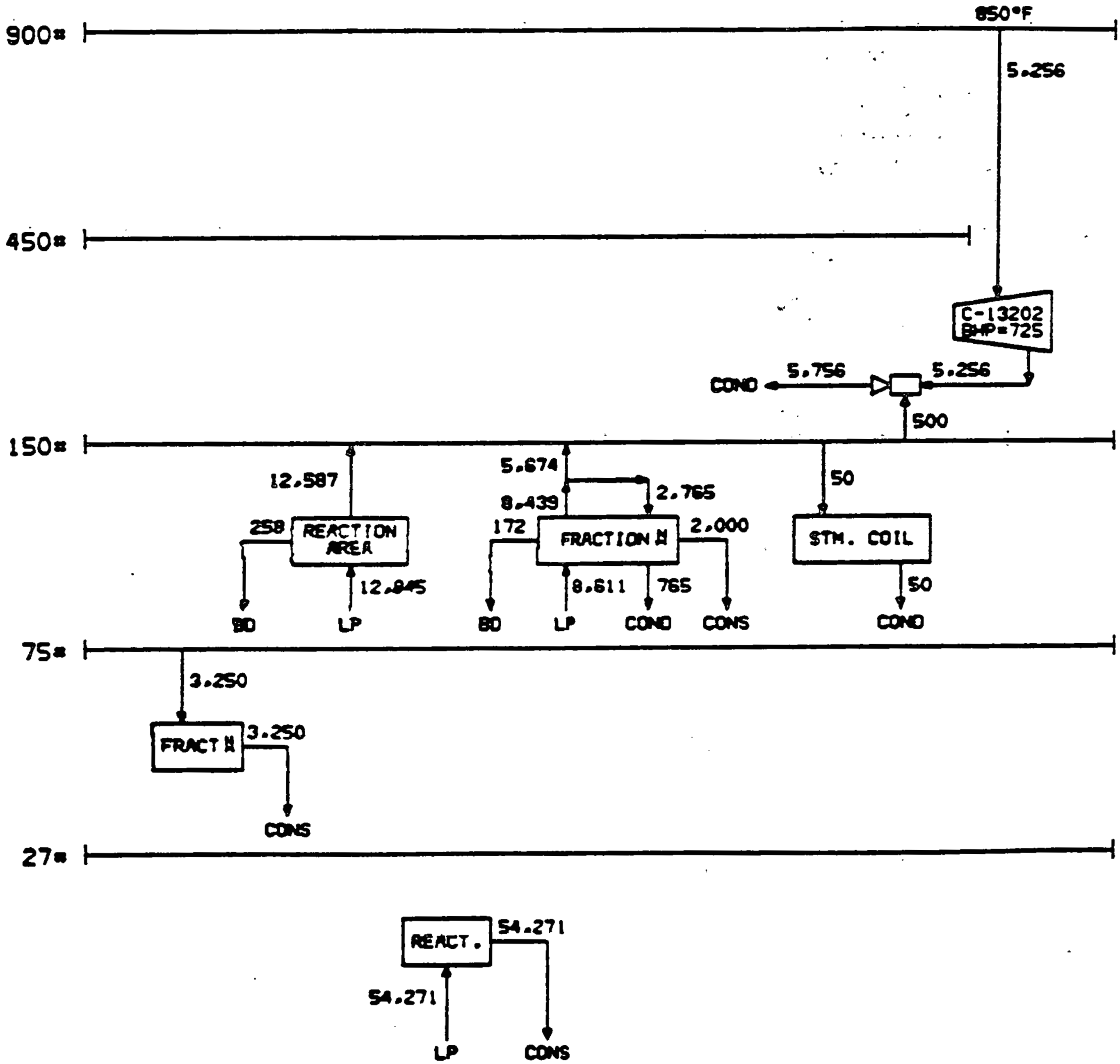
F30190

REV.	STEAM REQUIREMENTS SUMMARY		FUEL REQ'D (MM BTU/HR), LHV
AREA 13 EBH HIGH CONV.	HP BFW - -	75#, SAT - 3,300	
BASIS NORMAL BASELINE II	LP BFW - 82,943	27#, SAT - -	GAS = 31.61
DATE 12/3/82	900#, 850°F - 5,256	BLOWDOWN - (448)	LPG = 0.32
BY TDV	900#, SAT - -	CONSUMED - (65,021)	
	450#, SAT - -	CONDENSED - (6,571) 146°F	
	150#, SAT - (19,459)	TOTAL 0	



F30192

REV.	**STEAM REQUIREMENTS SUMMARY**	FUEL REQ'D (MM BTU/HR), LHV
AREA 13 EBH LOW CONV.	HP BFW - - / 75#, SAT - 3,250	GAS = 42.10
BASIS NORMAL BASELINE II	LP BFW - 75,727 / 27#, SAT - -	LPG = 0.42
DATE 12/3/82	900#, 850°F - 5,256 / BLOWDOWN - (430)	
BY TDV	900#, SAT - - / CONSUMED - (59,521)	
	450#, SAT - - / CONDENSED - (6,571) 146°F	
	150#, SAT - (17,711) / TOTAL 0	



REV.	
AREA	13-C/C
BASIS	NORMAL BASELINE II
DATE	12/3/82
BY	TDV

STEAM REQUIREMENTS SUMMARY

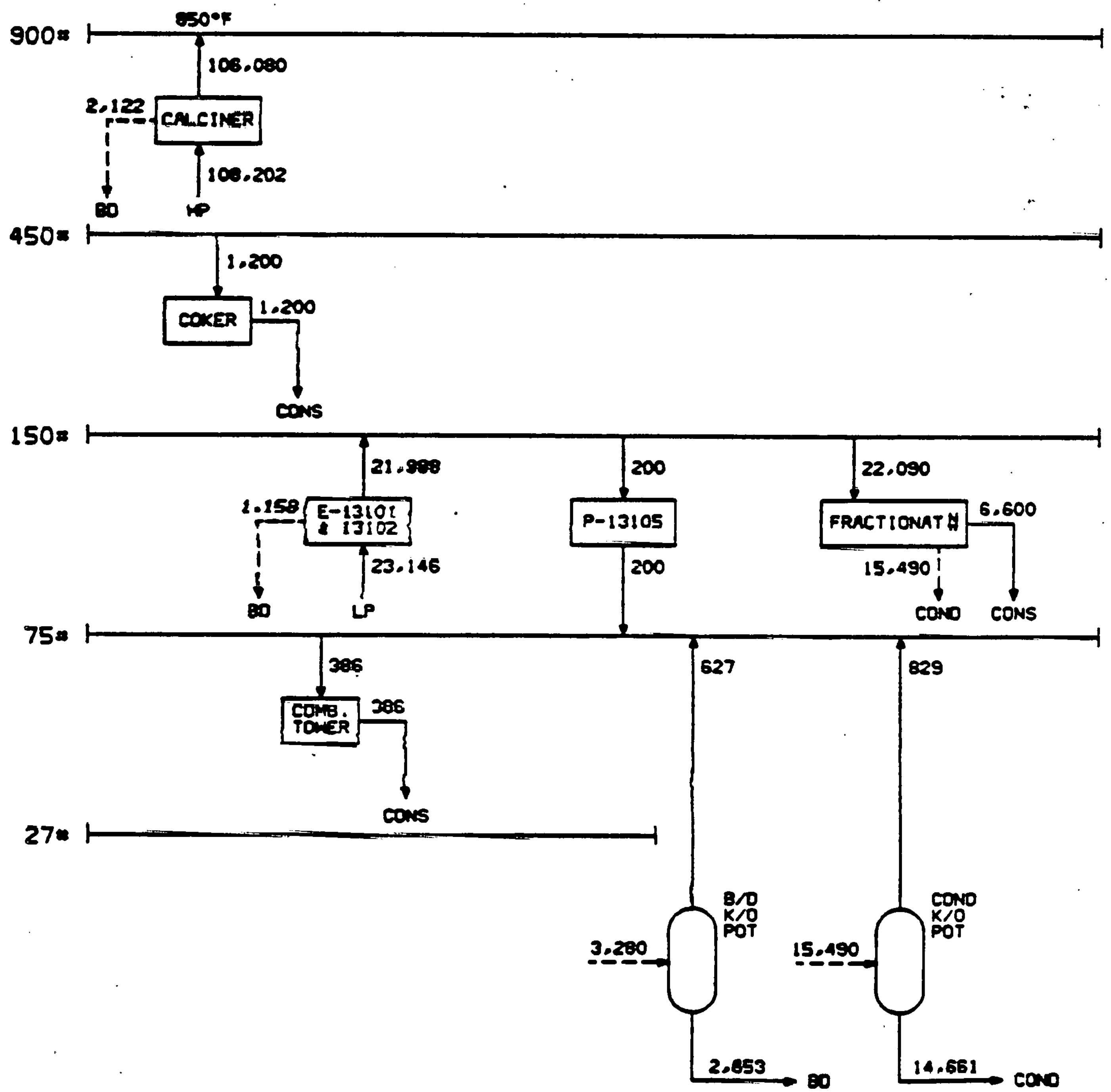
HP BFW	- 108,202	75#,SAT	-(1,270)	
LP BFW	- 23,146	27#,SAT	- -	
900#,850°F	-(106,080)	BLOWDOWN	-(2,653)	
900#,SAT	- -	CONSUMED	-(8,186)	
450#,SAT	- 1,200	CONDENSED	-(14,661)	320°F
150#,SAT	- 302	TOTAL	0	

FUEL REQ'D

(MM BTU/HR),LHV

GAS = 75.21

LPG = 0.75



F30191

REV.		**STEAM REQUIREMENTS SUMMARY**						**FUEL REQ'D** (MM BTU/HR), LHV
AREA	14-ASU ONLY	HP BFW	-	-	75#, SAT	-	-	
BASIS	NORMAL BASELINE II	LP BFW	-	-	27#, SAT	-	-	GAS # -
DATE	12/3/82	900#, 850°F	-	-	BLOWDOWN	-	-	
BY	TDV	900#, SAT	-	-	CONSUMED	-	-	LPG # -
		450#, SAT	-	-	CONDENSED	-	-	
		150#, SAT	-	-	TOTAL		0	

900#

450#

150#

75#

27#

REV. 1 1/10/82

AREA 15 & HPU

BASIS NORMAL BASELINE II

DATE 12/15/82

BY TDV

STEAM REQUIREMENTS SUMMARY

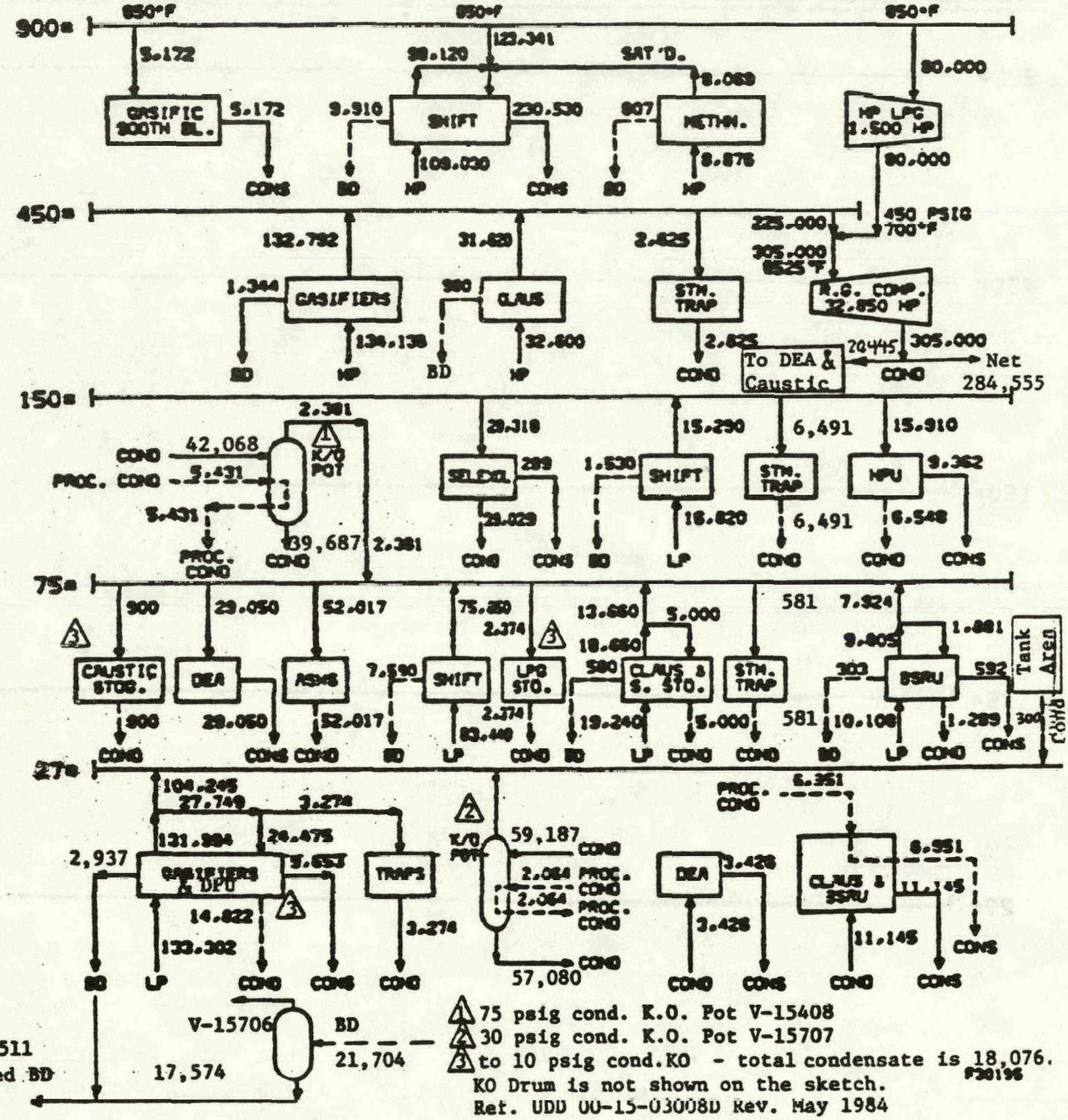
HP BFW	- 284,642	75#,SAT	-(14,052)
LP BFW	- 262,910	27#,SAT	-(108,738)
900#,850°F	- 208,513	BLOWDOWN	-(20,511)
900#,SAT	- -	CONSUMED	-(299,219)
450#,SAT	- 83,213	CONDENSED	-(399,398)
150#,SAT	- 39,039	TOTAL	

FUEL REQ'D

(MM BTU/HR),LHV

GAS = 6.6

LPG = 13.1



75 psig cond. K.O. Pot V-15408

30 psig cond. K.O. Pot V-15707

to 10 psig cond.KO - total condensate is 18,076.

KO Drum is not shown on the sketch.

Ref. UDD 00-15-03008D Rev. May 1984

F30196

REV.

AREA 16 EXCEPT STM. SYSTEM

BASIS NORMAL BASELINE II

DATE 12/3/82

BY TDV

STEAM REQUIREMENTS SUMMARY

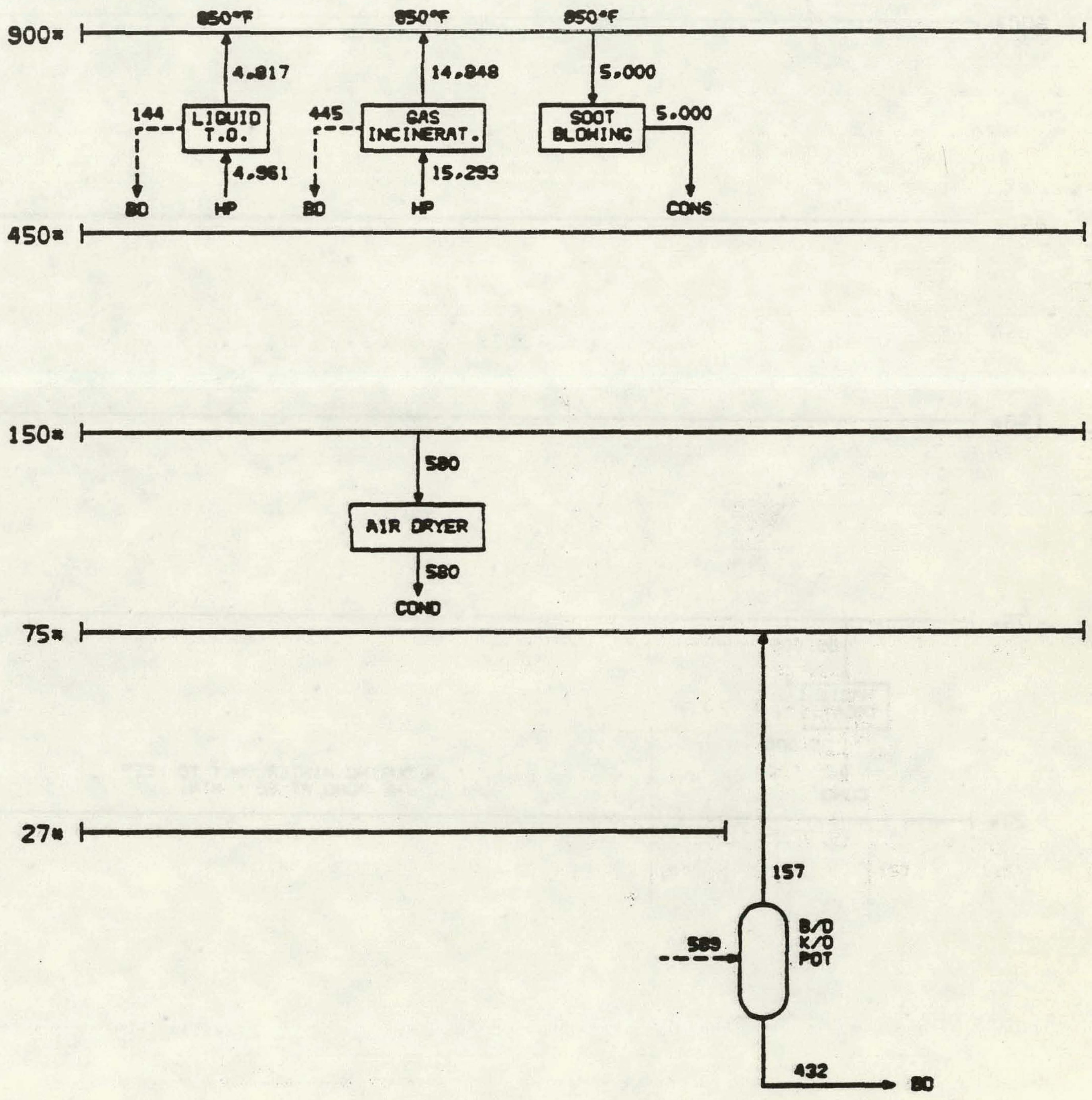
HP BFW	- 20,254	75#,SAT	- (157)
LP BFW	- -	27#,SAT	- -
900#,850°F	-(14,665)	BLOWDOWN	- (432)
900#,SAT	- -	CONSUMED	-(5,000)
450#,SAT	- -	CONDENSED	- (580)
150#,SAT	- 580	TOTAL	0

FUEL REQ'D

(MM BTU/HR),LHV

GAS = 30.2

LPG = 3.4



F30196

REV.

AREA 17

BASIS NORMAL BASELINE II

DATE 12/3/82

BY TDV

STEAM REQUIREMENTS SUMMARY

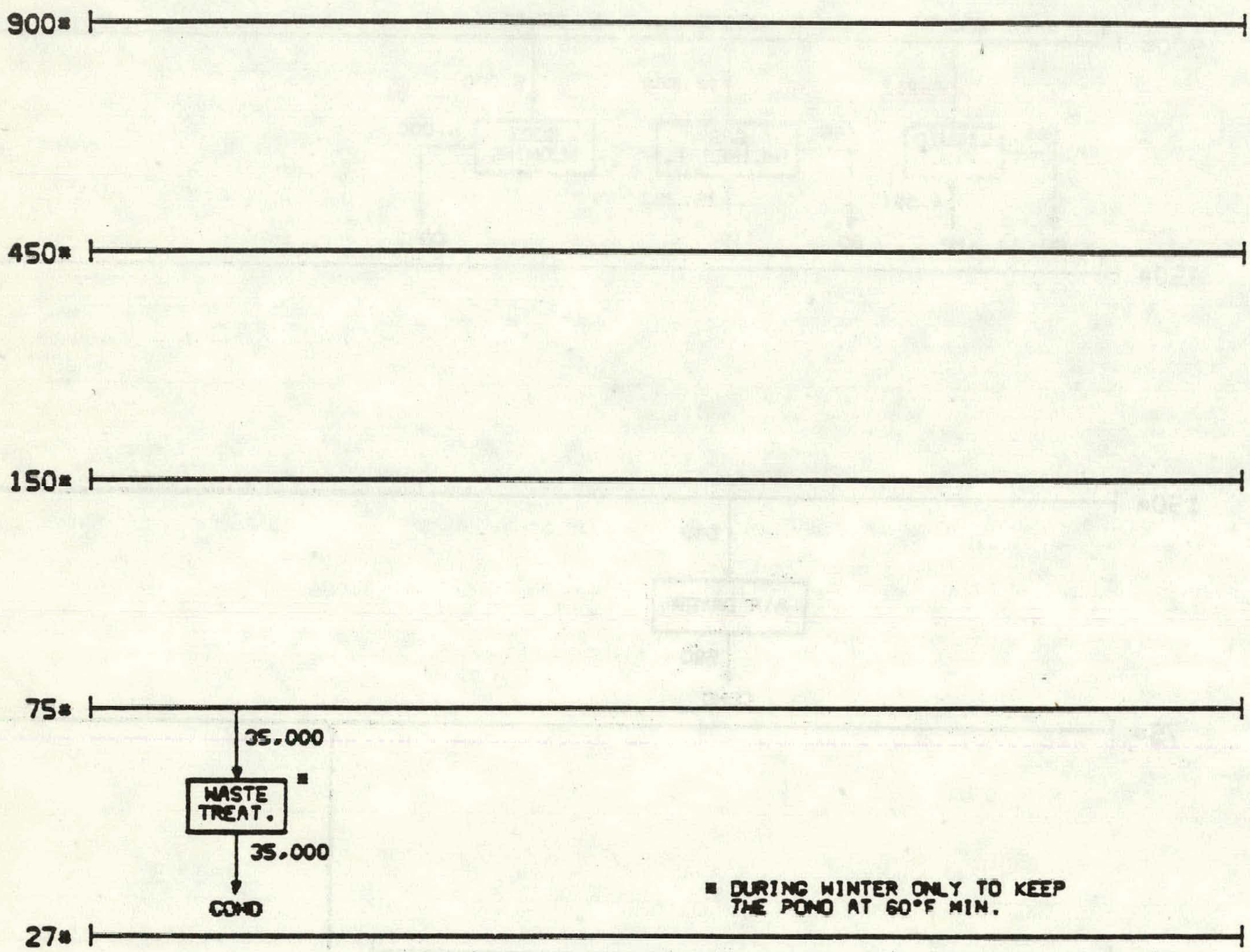
HP BFW	-	-	75#, SAT	-	35,000
LP BFW	-	-	27#, SAT	-	-
900#, 850°F	-	-	BLOWDOWN	-	-
900#, SAT	-	-	CONSUMED	-	-
450#, SAT	-	-	CONDENSED	-	(35,000)
150#, SAT	-	-	TOTAL		0

FUEL REQ'D

(MM BTU/HR), LHV

GAS # -

LPG # -



F30197

REV.	
AREA	NHT
BASIS	NORMAL BASELINE II
DATE	12/3/82
BY	TDV

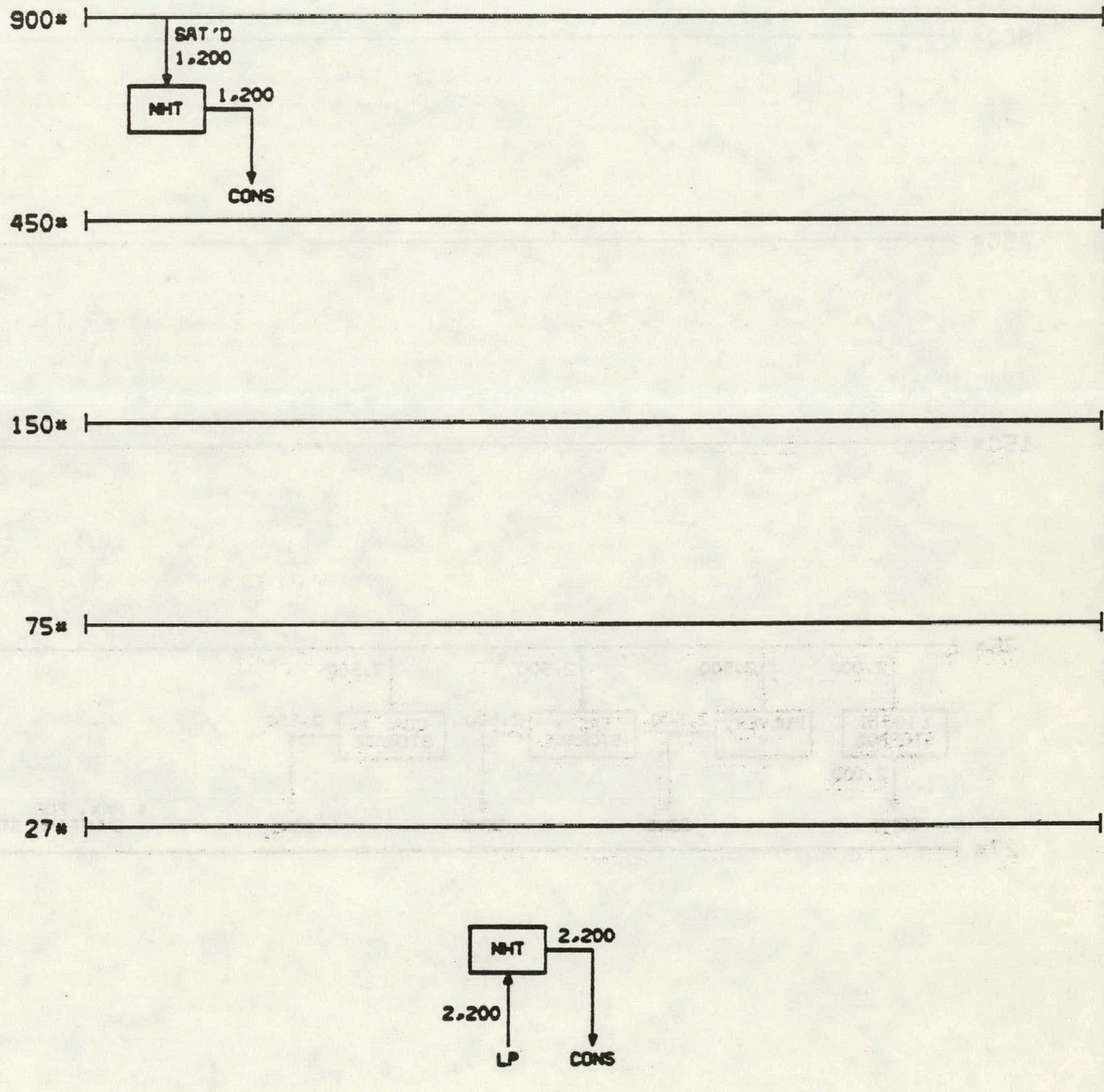
STEAM REQUIREMENTS SUMMARY

HP BFW	-	-	75#,SAT	-	-
LP BFW	-	2,200	27#,SAT	-	-
900#,850°F	-	-	BLOWDOWN	-	-
900#,SAT	-	1,200	CONSUMED	-	(3,400)
450#,SAT	-	-	CONDENSED	-	-
150#,SAT	-	-	TOTAL		0

FUEL REQ'D
(MM BTU/HR),LHV

GAS = 25.1

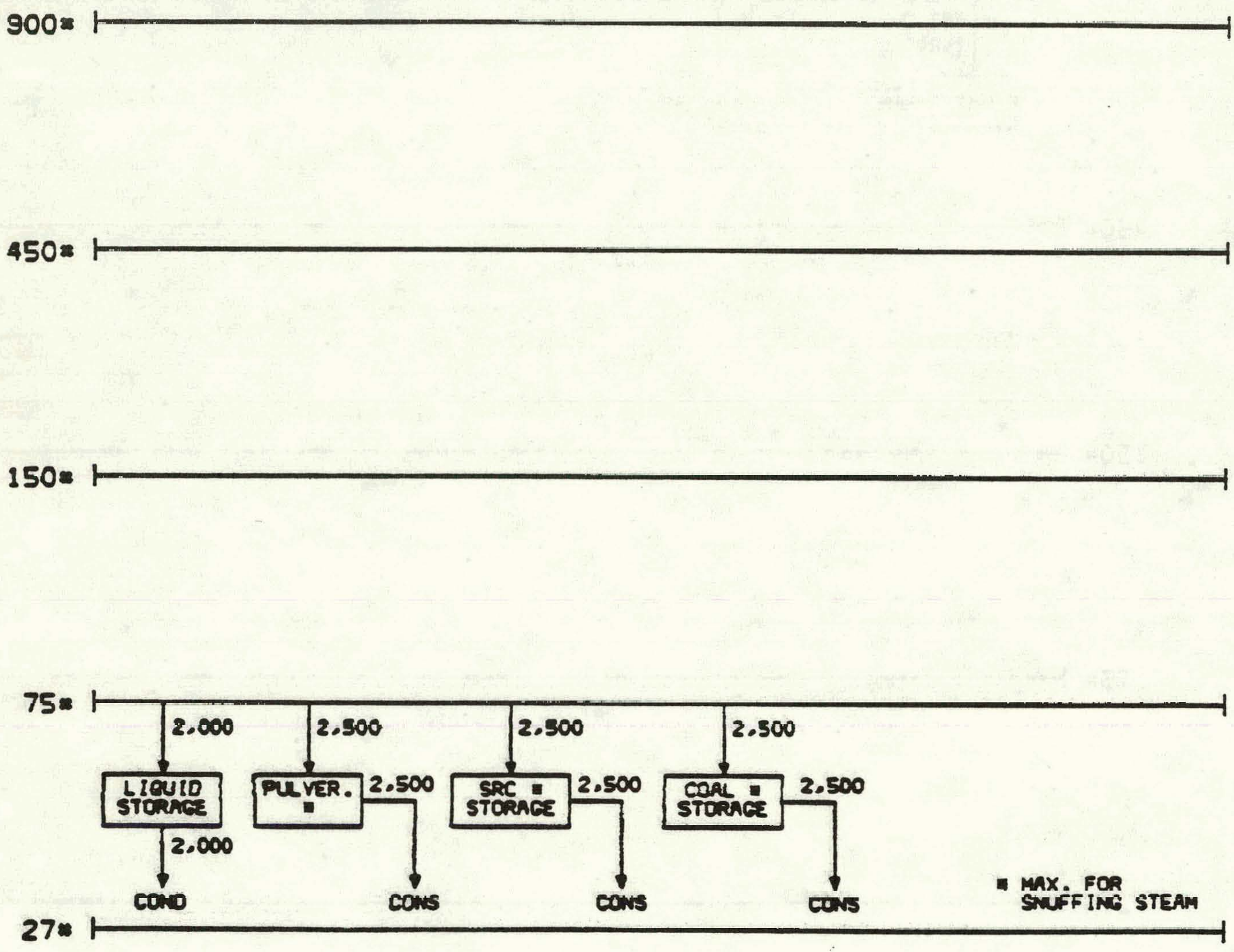
LPG = 0.25



F3013

REV.						FUEL REQ'D
AREA 11	HP BFW	-	-	75#, SAT	- 9,500	(MM BTU/HR), LHV
BASIS MAXIMUM BASELINE II	LP BFW	-	-	27#, SAT	- -	
DATE 12/3/82	900#, 850°F	-	-	BLOWDOWN	- -	GAS = 68.3
BY TDV	900#, SAT	-	-	CONSUMED	-(7,500)	LPG = 0.5
	450#, SAT	-	-	CONDENSED	-(2,000)	
	150#, SAT	-	-	TOTAL	0	

STEAM REQUIREMENTS SUMMARY



F30199

REV. 1 1/10/82

AREA 12

BASIS MAXIMUM BASELINE II

DATE 12/15/82

BY TDV

STEAM REQUIREMENTS SUMMARY

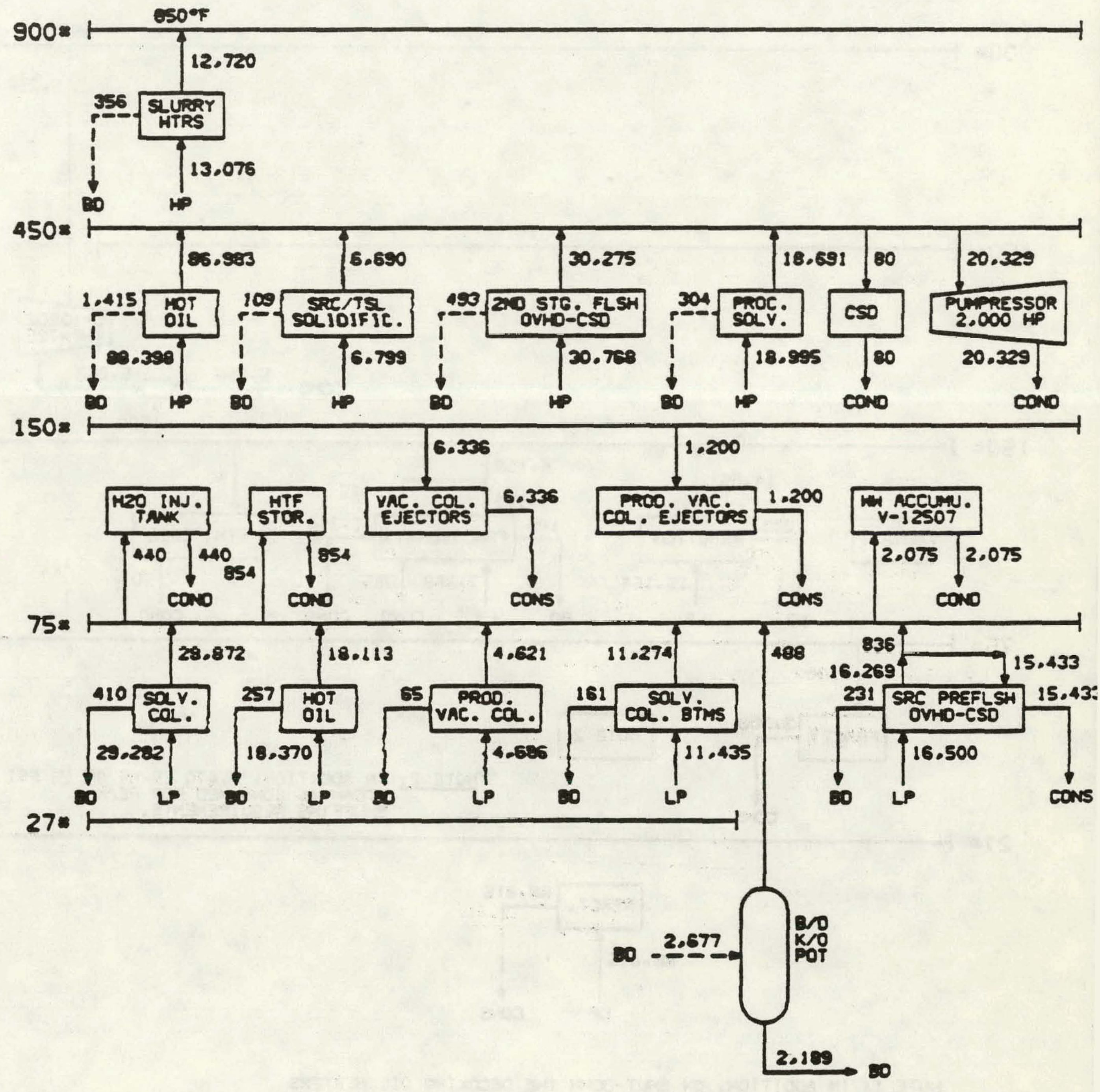
HP BFW	- 158,036	75#, SAT	-(60,835)
LP BFW	- 80,273	27#, SAT	- -
900#, 850°F	-(12,720)	BLOWDOWN	-(3,313)
900#, SAT	- -	CONSUMED	-(22,969)
450#, SAT	-(122,230)	CONDENSED	-(23,778)
150#, SAT	- 7,536	TOTAL	0

FUEL REQ'D

(MM BTU/HR), LHV

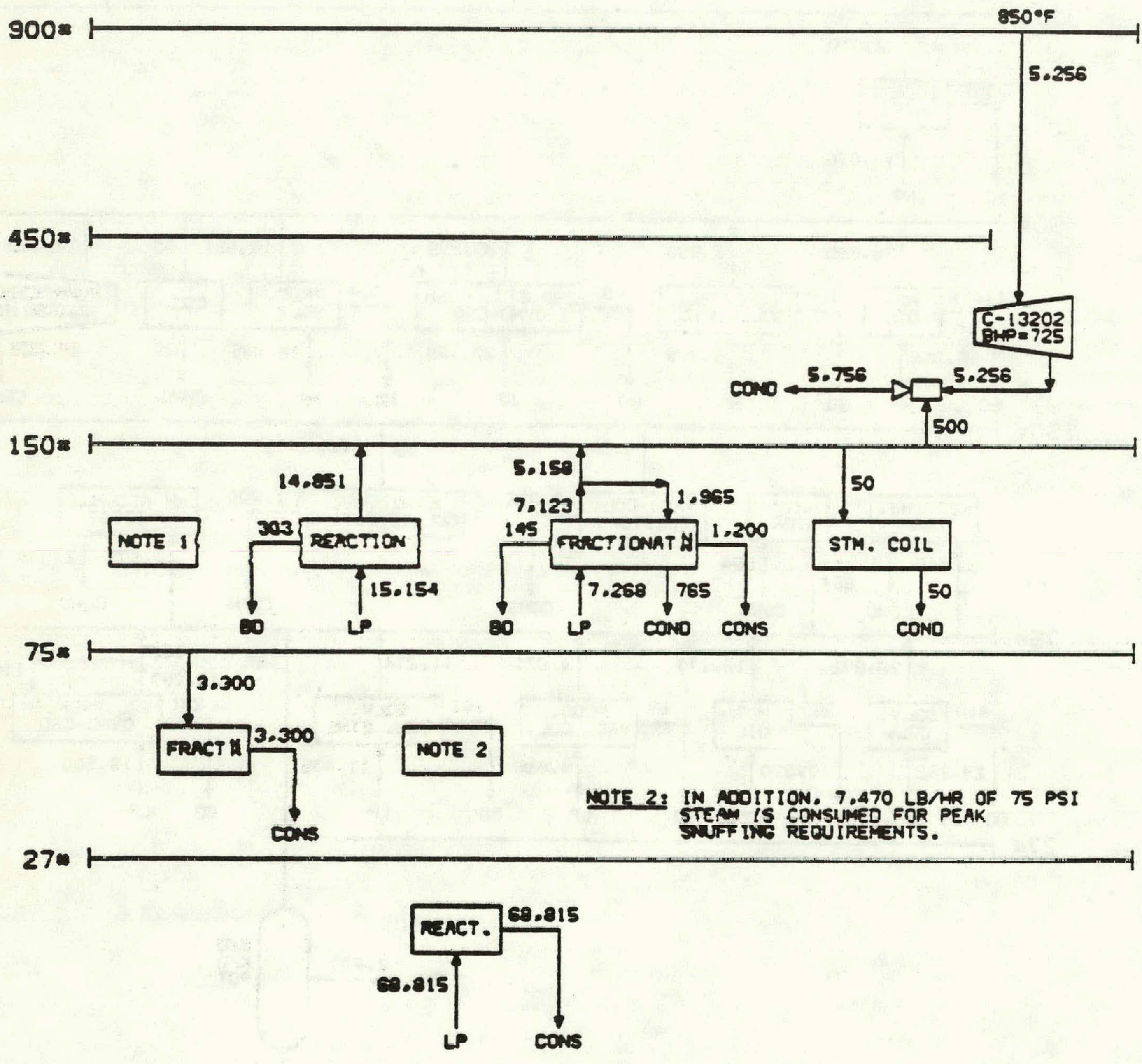
GAS = 518.4

LPG = 5.2



F30200

REV.	STEAM REQUIREMENTS SUMMARY				FUEL REQ'D (MM BTU/HR), LHV
AREA 13 EBH	HP BFW	-	75#, SAT	3,300	
BASIS MAXIMUM BASELINE II	LP BFW	91,237	27#, SAT	-	GAS = 72.35
DATE 12/3/82	900#, 850°F	5,256	BLOWDOWN	(448)	LPG = 0.72
BY TDV	900#, SAT	-	CONSUMED	(73,315)	
	450#, SAT	-	CONDENSED	(6,571) 146°F	
	150#, SAT	(19,459)	TOTAL	0	

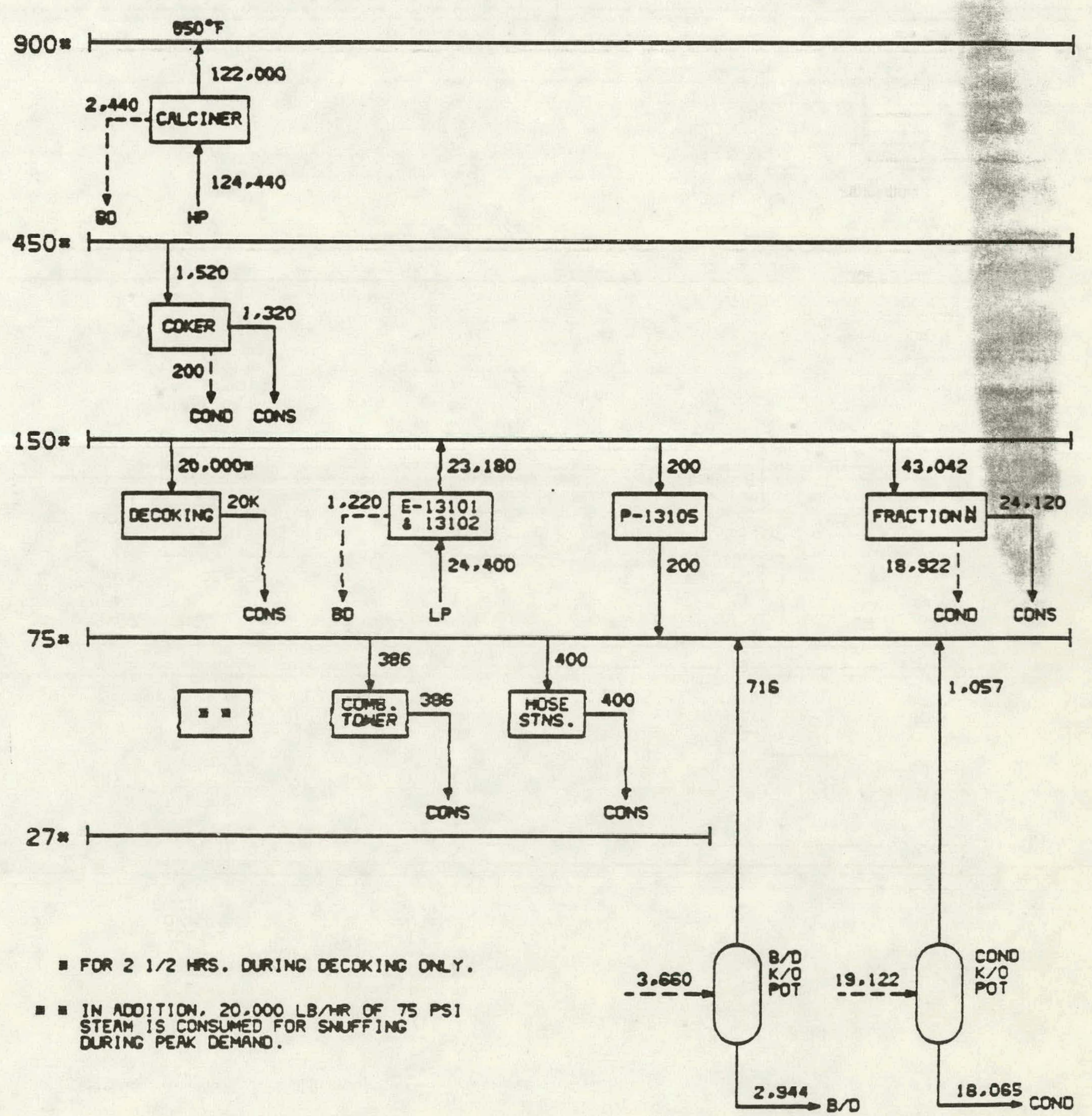


NOTE 2: IN ADDITION, 7,470 LB/HR OF 75 PSI STEAM IS CONSUMED FOR PEAK SNUFFING REQUIREMENTS.

NOTE 1: IN ADDITION, ON SHUT-DOWN THE DECOKING OIL HEATERS CONSUME 30,485 LB/HR OF 150 PSI STEAM FOR TWO DAYS. WHEN THIS HAPPENS, THE OTHER 150 PSI STEAM GENERATION IS ZERO.

F30202

REV.		STEAM REQUIREMENTS SUMMARY		FUEL REQ'D (MM BTU/HR), LHV
AREA	13-C/C	HP BFW - 124,440	75*, SAT - (1,187)	GAS = 75.65
BASIS	MAXIMUM BASELINE II	LP BFW - 24,400	27*, SAT - -	LPG = 0.76
DATE	12/3/82	900*, 850°F - (122,000)	BLOWDOWN - (2,944)	
BY	TDV	900*, SAT - -	CONSUMED - (46,226)	
		450*, SAT - 1,520	CONDENSED - (18,065) 320°F	
		150*, SAT - 40,062	TOTAL 0	



* FOR 2 1/2 HRS. DURING DECOKING ONLY.

* * IN ADDITION, 20,000 LB/HR OF 75 PSI STEAM IS CONSUMED FOR SNUFFING DURING PEAK DEMAND.

F30201

REV.	
AREA	14-ASU ONLY
BASIS	MAXIMUM BASELINE II
DATE	12/3/82
BY	TDV

STEAM REQUIREMENTS SUMMARY

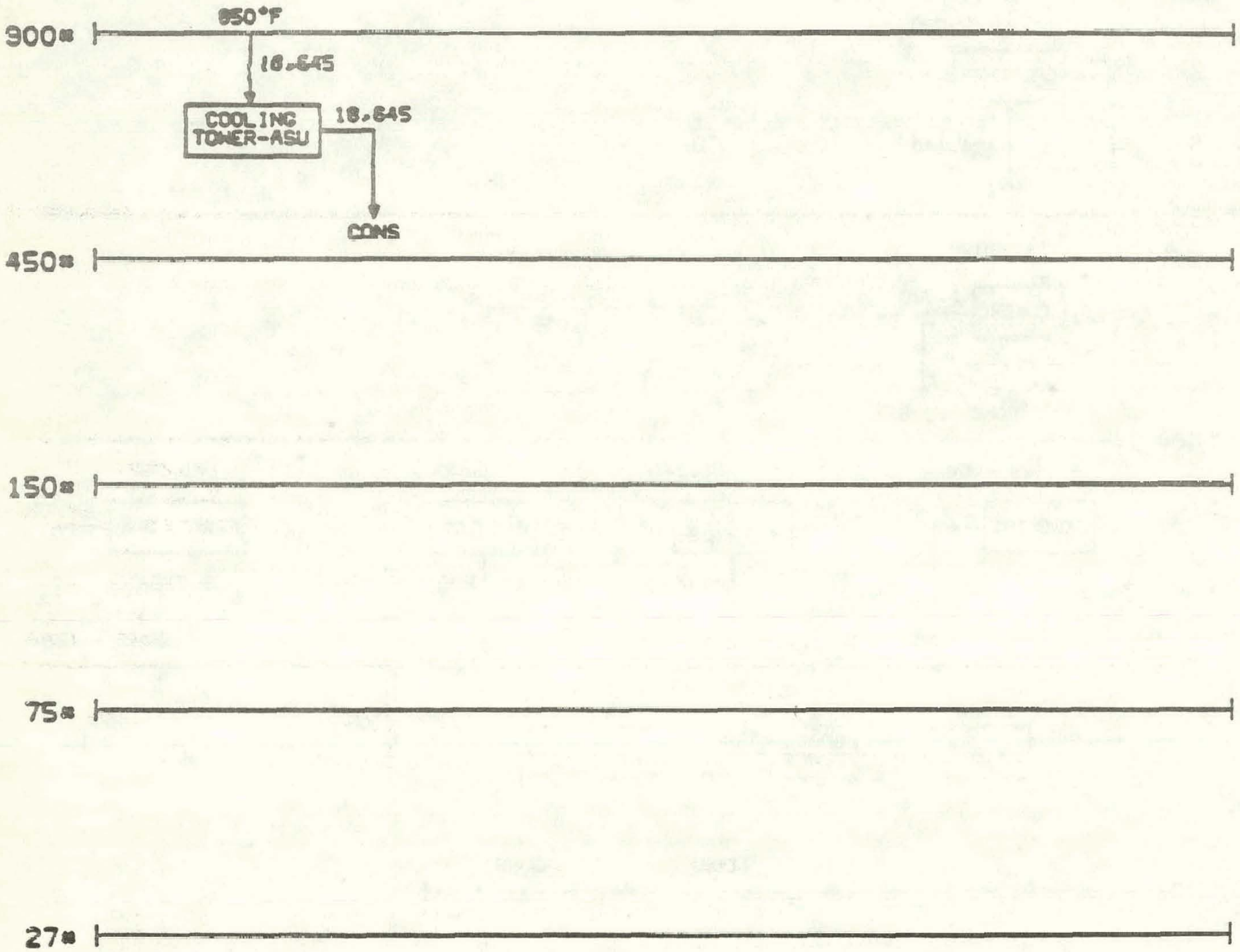
HP BFW	-	-	75#,SAT	-	-
LP BFW	-	-	27#,SAT	-	-
900#,850°F	-	18,645	BLOWDOWN	-	-
900#,SAT	-	-	CONSUMED	-	(18,645)
450#,SAT	-	-	CONDENSED	-	-
150#,SAT	-	-	TOTAL		0

FUEL REQ'D

(MM BTU/HR),LHV

GAS = -

LPG = -



F30203

REV.

AREA 15 & HPU

BASIS MAXIMUM STEAM DEMAND

DATE 1/13/83

BY TDV

STEAM REQUIREMENTS SUMMARY

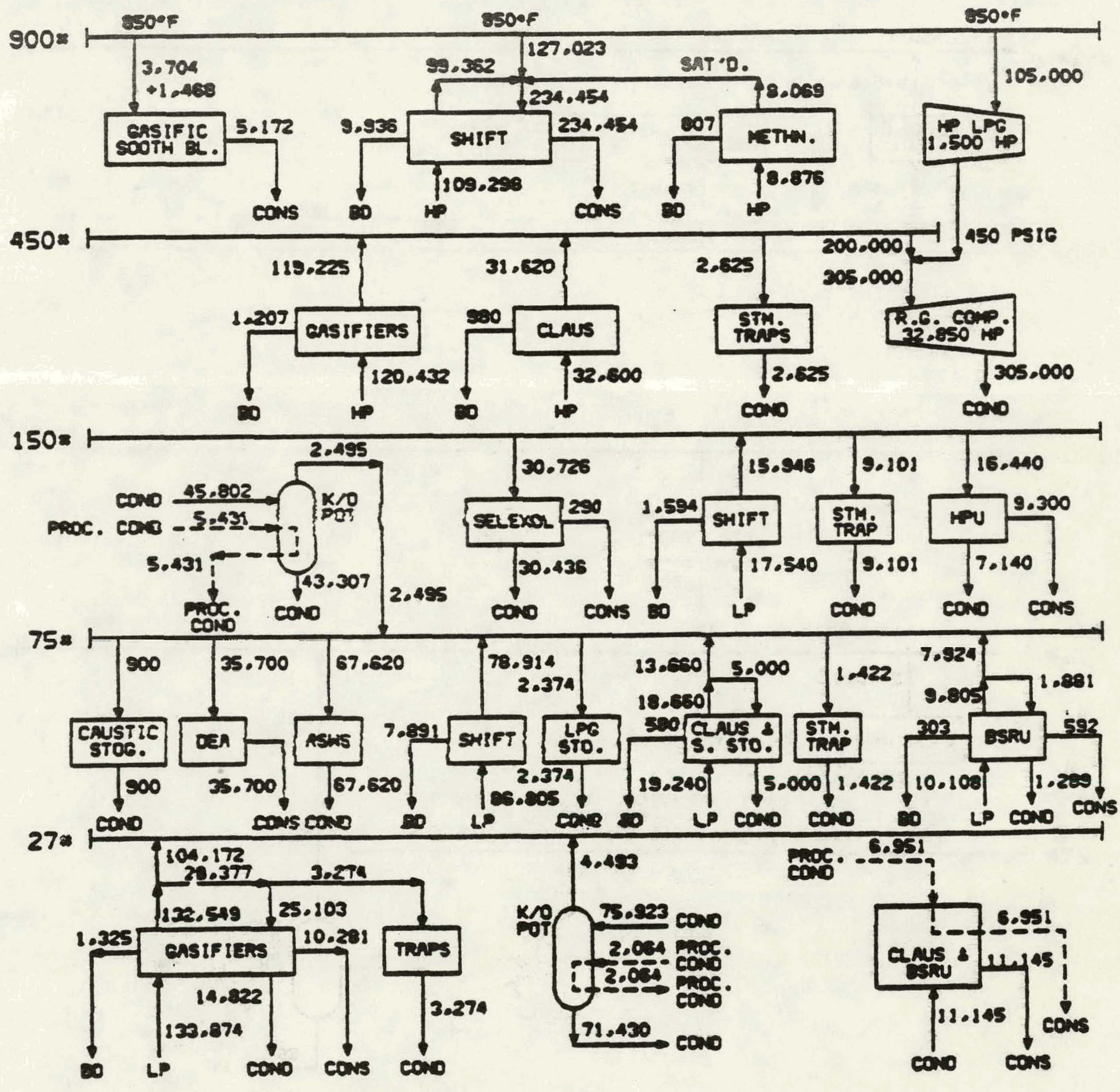
HP BFW	- 271,206	75#, SAT	- 5,023
LP BFW	- 267,567	27#, SAT	-(108,665)
900#, 850°F	- 237,195	BLOWDOWN	-(24,623)
900#, SAT	- -	CONSUMED	-(306,934)
450#, SAT	- 51,780	CONDENSED	-(432,870)
150#, SAT	- 40,321	TOTAL	0

FUEL REQ'D

(MM BTU/HR), LHV

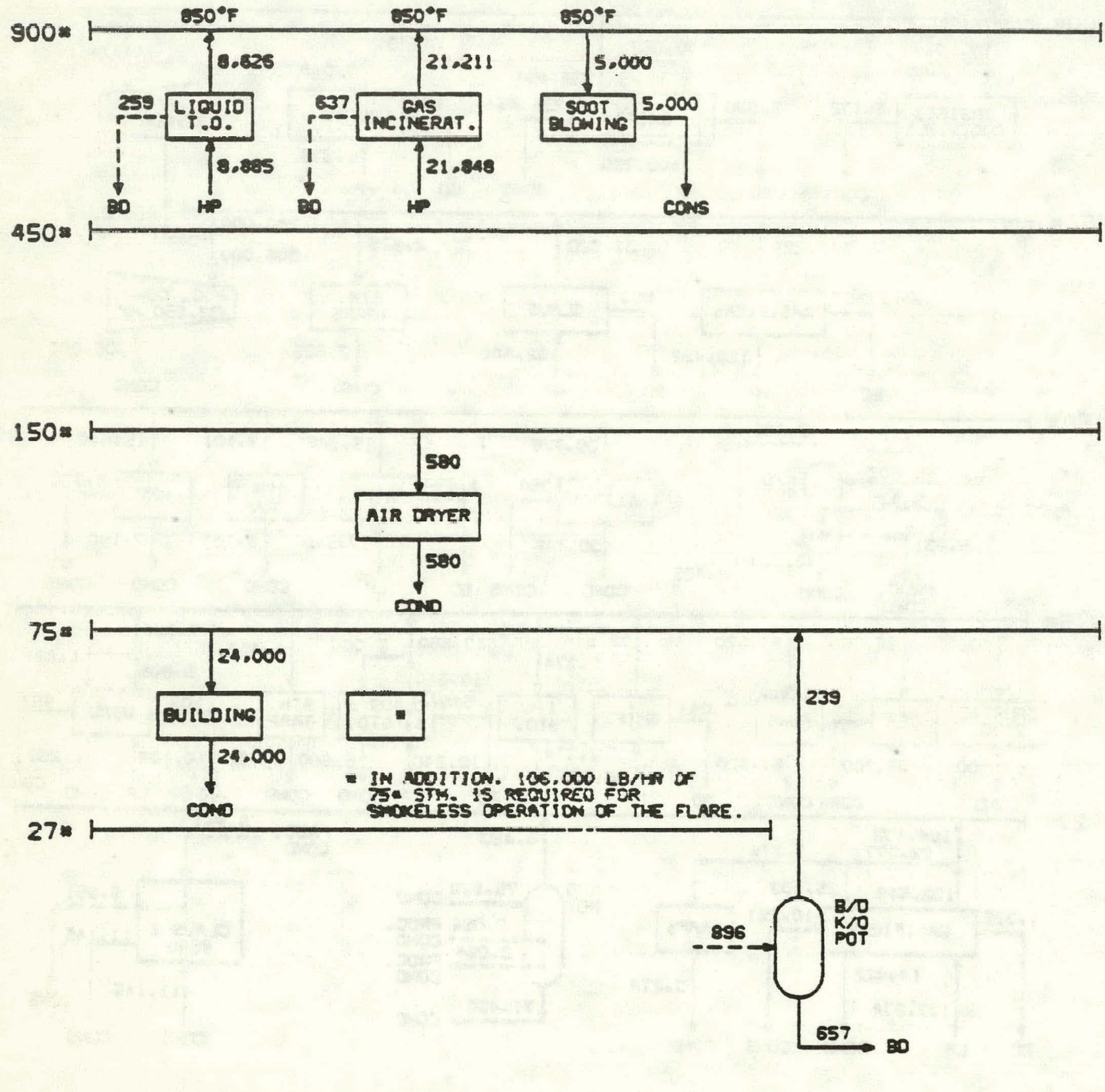
GAS = 6.6

LPG = 16.3



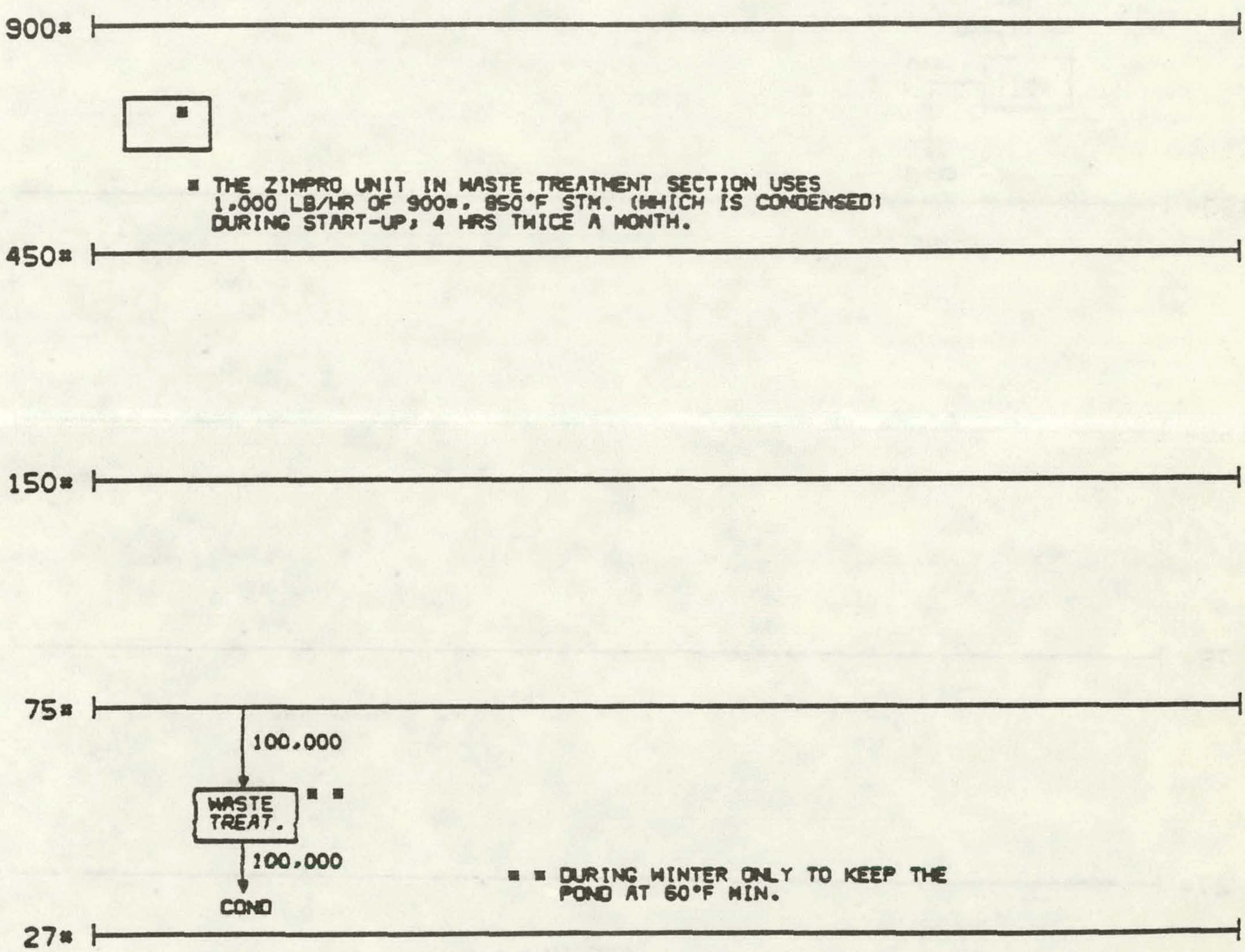
F30204

REV.	STEAM REQUIREMENTS SUMMARY			FUEL REQ'D
AREA 16 EXCEPT STM. SYSTEM	HP BFW - 30,733	75*, SAT - 23,761		(MM BTU/HR), LHV
BASIS MAXIMUM BASELINE II	LP BFW - -	27*, SAT - -		GAS = 44.3
DATE 12/3/82	900*, 850°F - (24,837)	BLOWDOWN - (657)		LPG = 3.4
BY TDV	900*, SAT - -	CONSUMED - (5,000)		
	450*, SAT - -	CONDENSED - (24,580)		
	150*, SAT - 580	TOTAL 0		



F30205

REV.	STEAM REQUIREMENTS SUMMARY		FUEL REQ'D (MM BTU/HR),LHV
AREA 17	HP BFW - -	75#,SAT - 100,000	
BASIS MAXIMUM BASELINE II	LP BFW - -	27#,SAT - -	GAS # -
DATE 12/3/82	900#,850°F - -	BLOWDOWN - -	
BY TDV	900#,SAT - -	CONSUMED - -	LPG # -
	450#,SAT - -	CONDENSED - (100,000)	
	150#,SAT - -	TOTAL 0	



F30206

REV.	
AREA	NHT
BASIS	MAXIMUM BASELINE II
DATE	12/3/82
BY	TDV

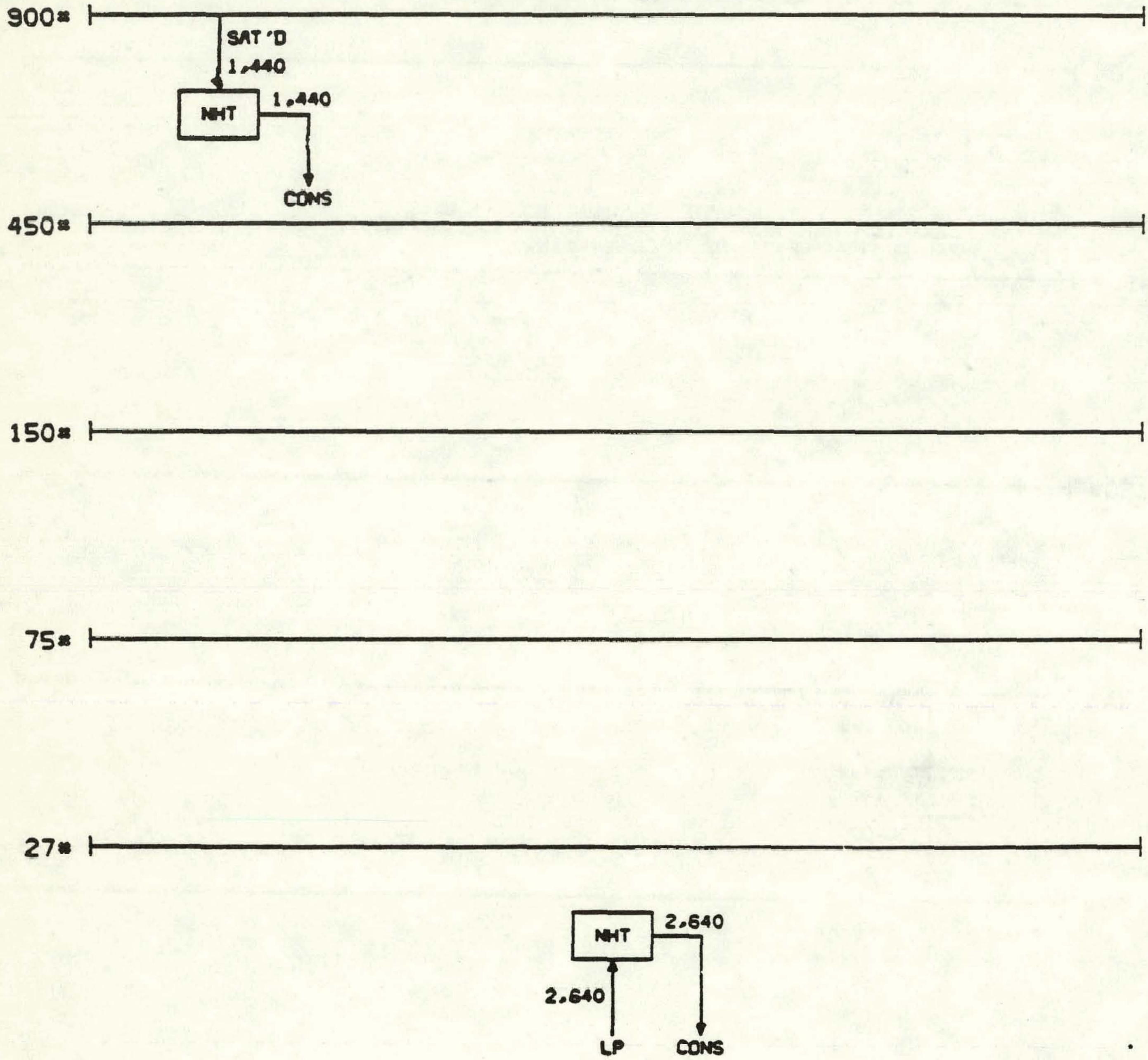
STEAM REQUIREMENTS SUMMARY

HP BFW	-	-	75#,SAT	-	-
LP BFW	-	2,640	27#,SAT	-	-
900#,850°F	-	-	BLOWDOWN	-	-
900#,SAT	-	1,440	CONSUMED	-	(4,080)
450#,SAT	-	-	CONDENSED	-	-
150#,SAT	-	-	TOTAL		0

FUEL REQ'D
(MM BTU/HR),LHV

GAS = 30.1

LPG = 0.25



F30207

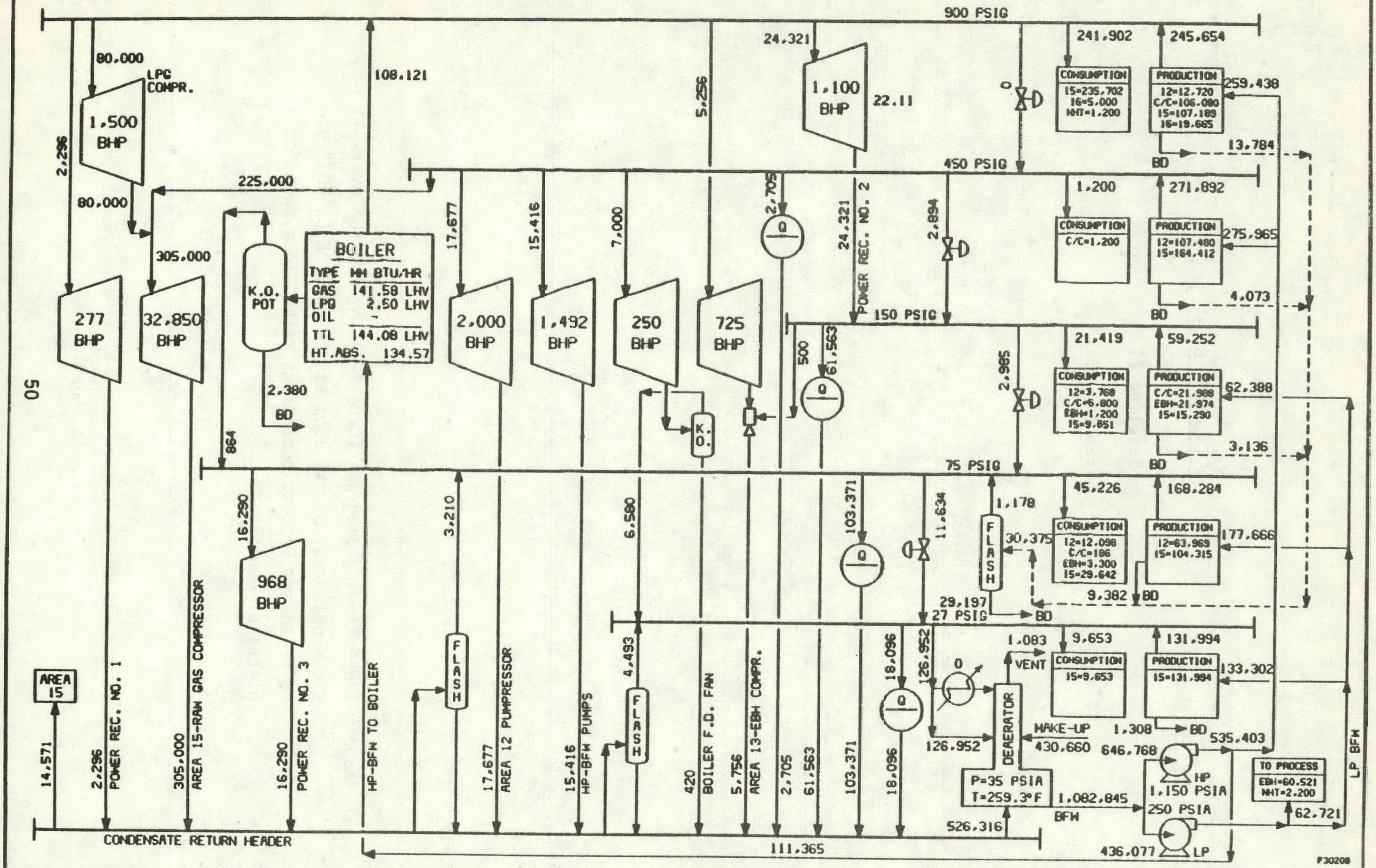
ATTACHMENT B

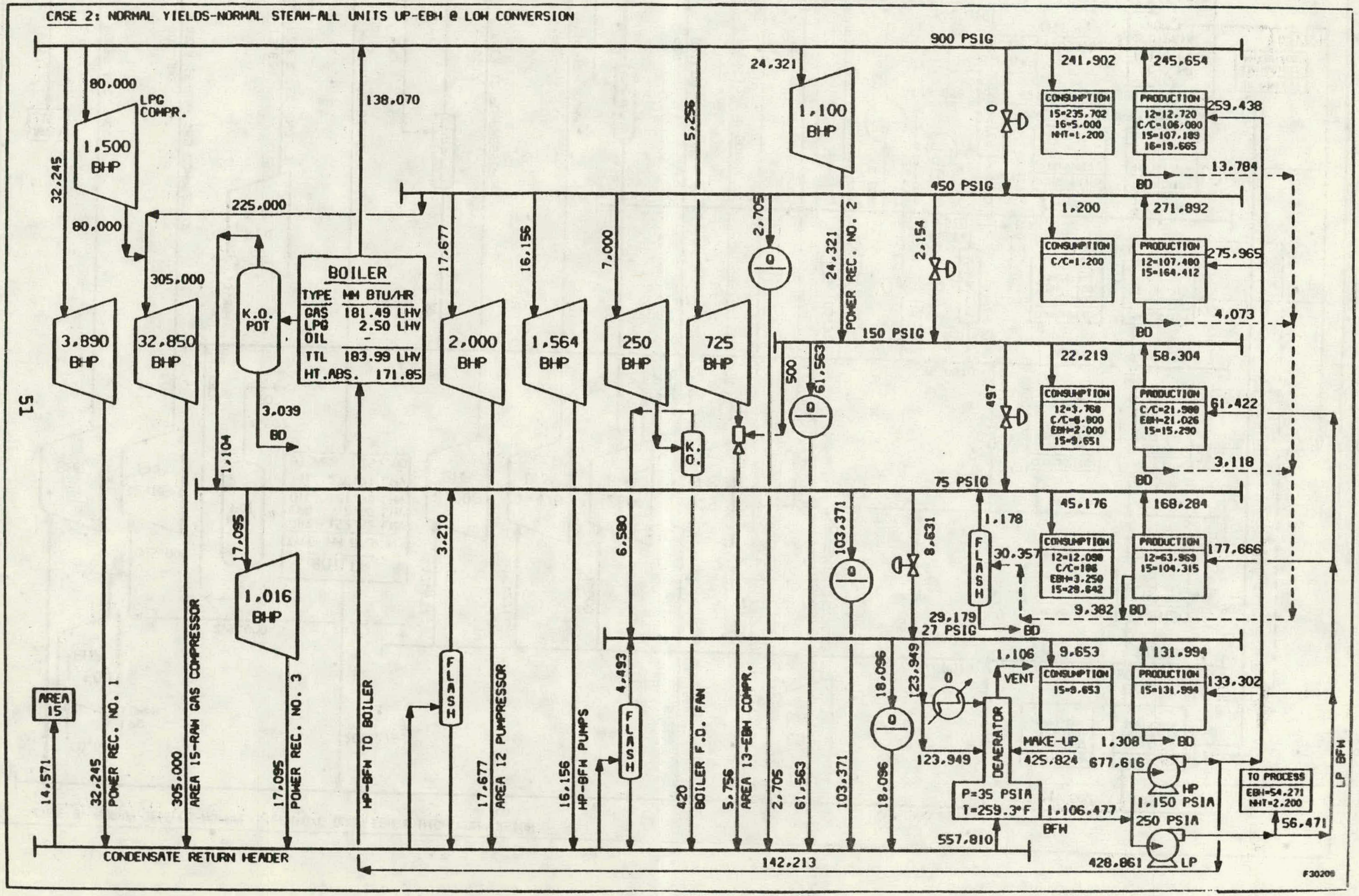
Baseline II

Steam Balances

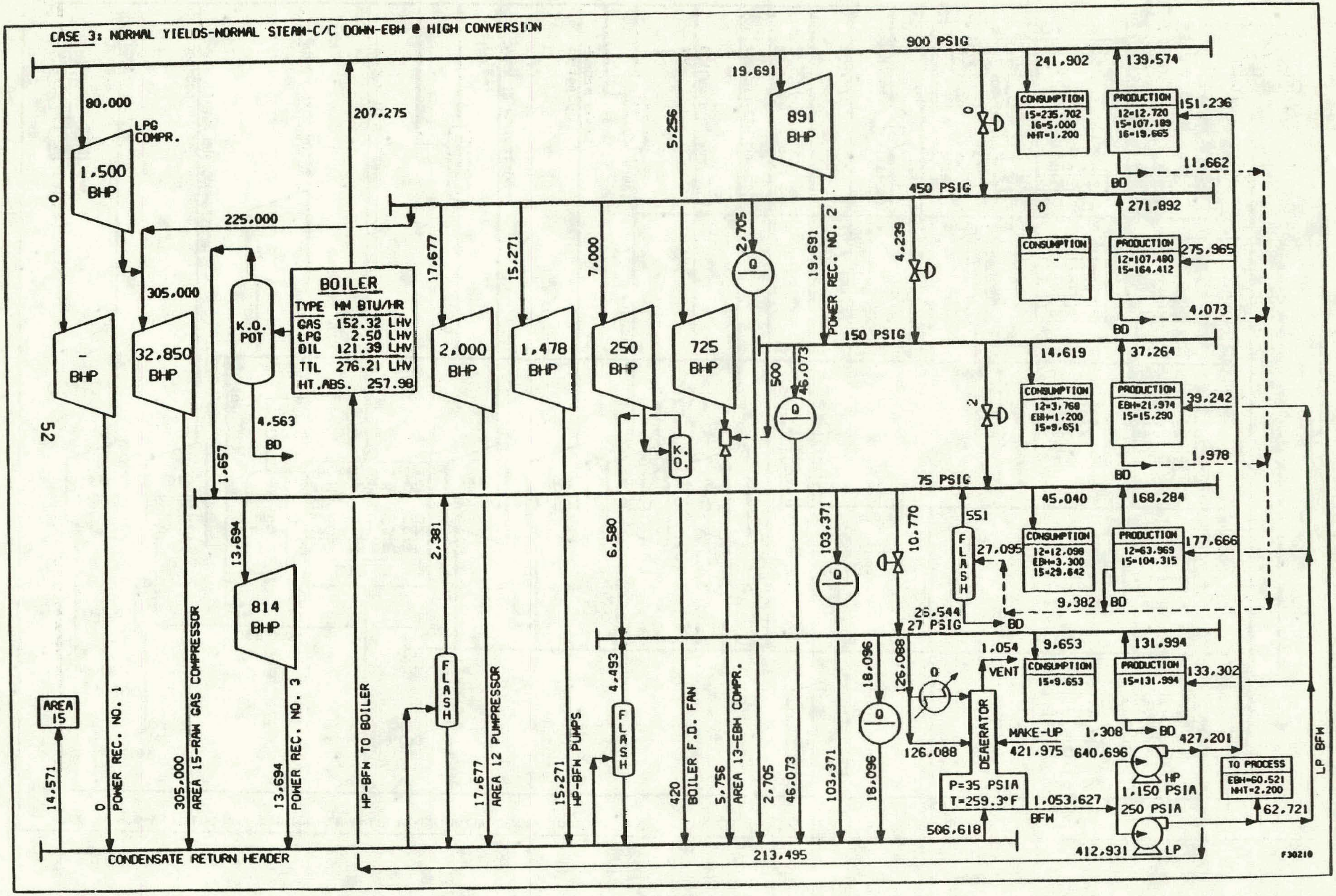
Note: The following diagrams (Case 1-7) reflect the over-all steam balances; blocks such as "FLASH", "K.O. POT" etc. refer to the Process operations rather than specific pieces of equipment.

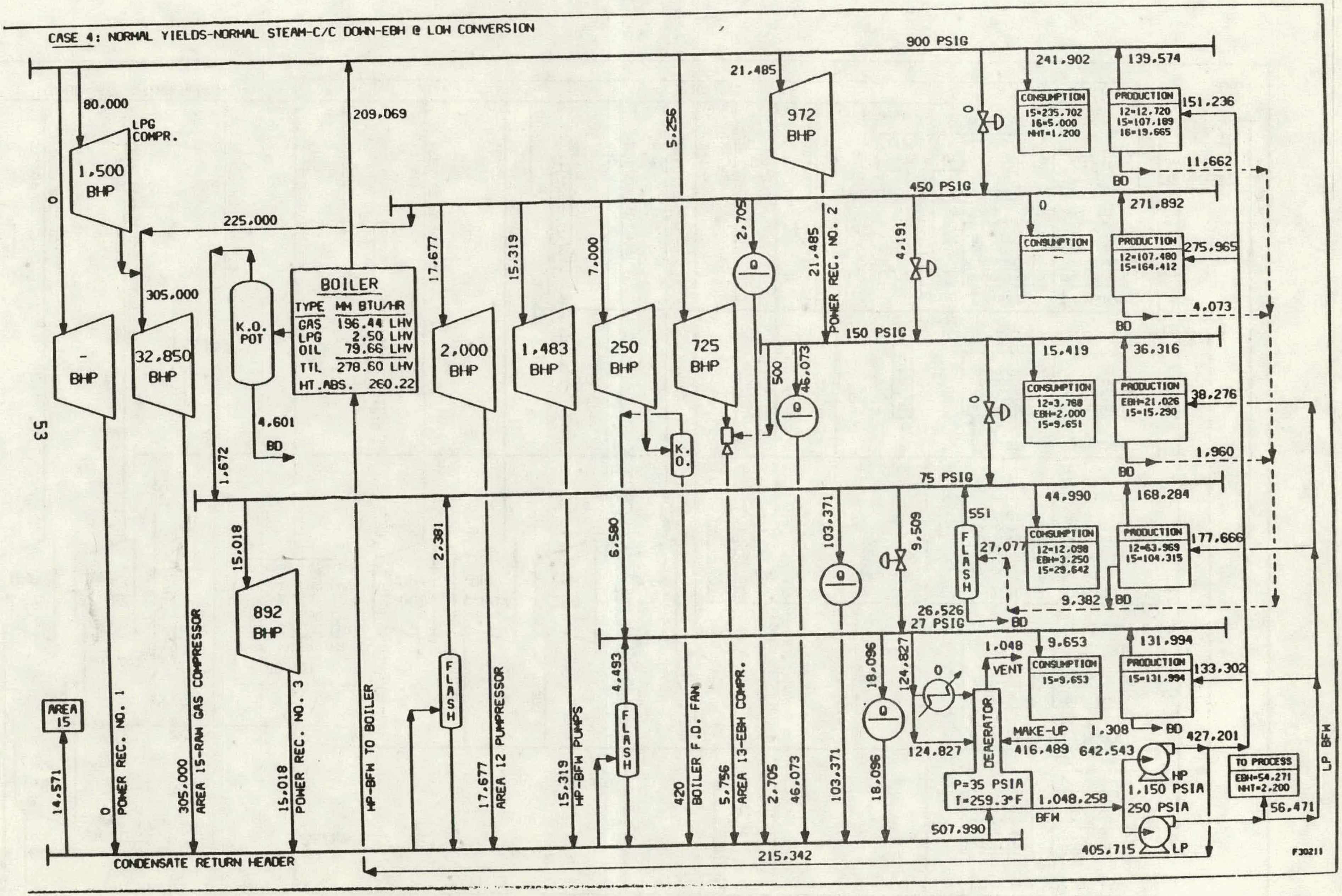
CASE 1: NORMAL YIELDS-NORMAL STEAM-ALL UNITS UP-EBH @ HIGH CONVERSION





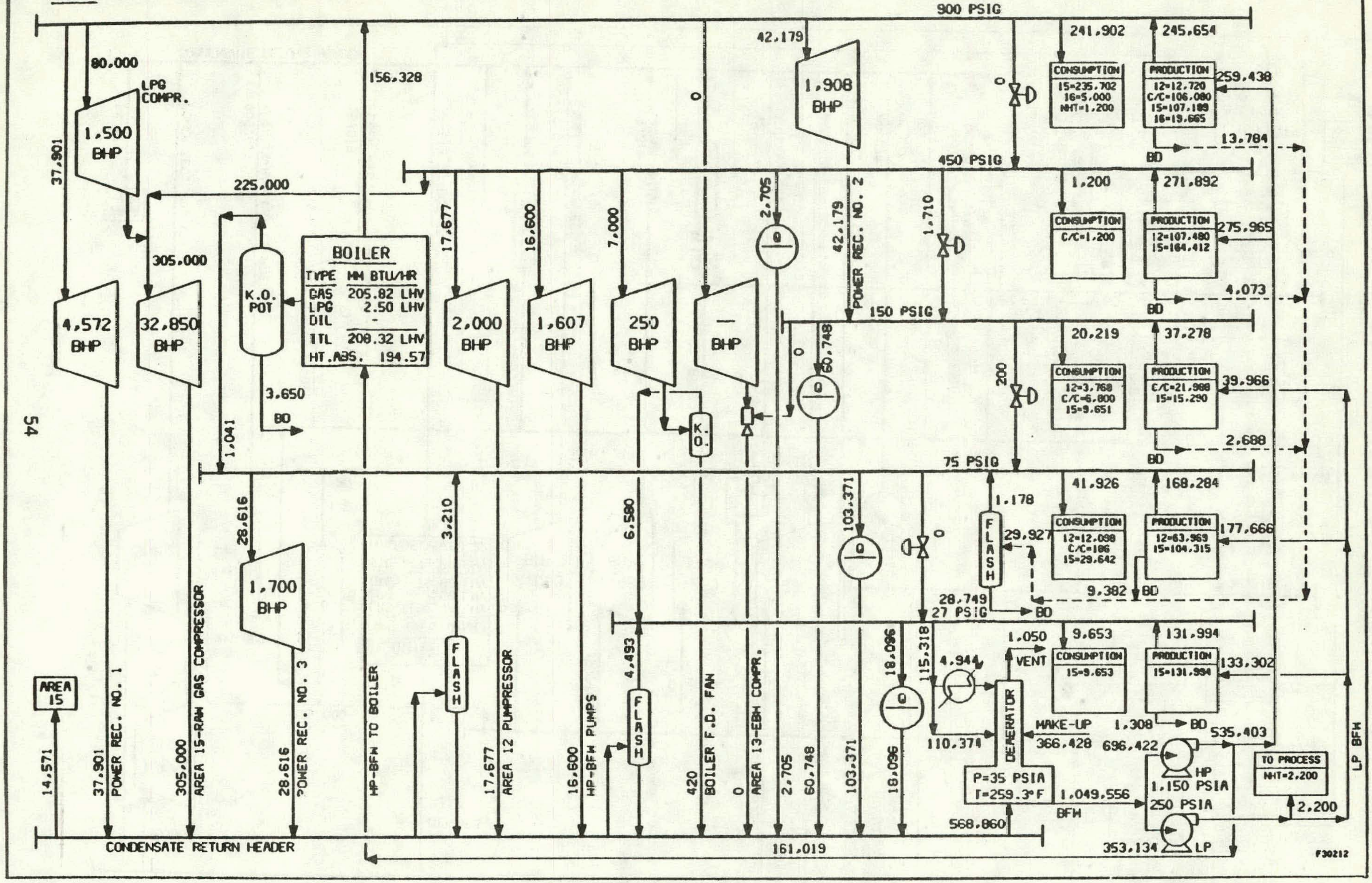
CASE 2: NORMAL YIELDS-NORMAL STEAM-ALL UNITS UP-EBH @ LOW CONVERSION
900 PSIG
450 PSIG
150 PSIG
75 PSIG
27 PSIG
CONDENSATE RETURN HEADER
LPG COMPR.
1,500 BHP
3,890 BHP
32,850 BHP
1,016 BHP
2,000 BHP
1,564 BHP
250 BHP
725 BHP
1,100 BHP
K.O. POT
BOILER
TYPE MM BTU/HR
GAS 181.49 LHV
LPG 2.50 LHV
OIL -
TTL 183.99 LHV
HT.ABS. 171.85
CONSUMPTION
15=235,702
16=5,000
NHT=1,200
PRODUCTION
12=12,720
C/C=106,080
15=107,189
16=19,665
CONSUMPTION
C/C=1,200
PRODUCTION
12=107,480
15=164,412
CONSUMPTION
12=3,768
C/C=6,800
EBH=2,000
15=9,651
PRODUCTION
C/C=21,988
EBH=21,026
15=15,290
CONSUMPTION
12=12,090
C/C=186
EBH=3,250
15=29,642
PRODUCTION
12=63,969
15=104,315
CONSUMPTION
15=9,653
PRODUCTION
15=131,994
DEAERATOR
P=35 PSIA
T=259.3°F
VENT
MAKE-UP
425,824
TO PROCESS
EBH=54,271
NHT=2,200
HP
1,150 PSIA
250 PSIA
LP
BFW
LP BFW
FLASH
K.O.
BD
AREA 15
POWER REC. NO. 1
POWER REC. NO. 2
POWER REC. NO. 3
AREA 15-RAW GAS COMPRESSOR
HP-BFW TO BOILER
AREA 12 PUMPRESSOR
HP-BFW PUMPS
BOILER F.D. FAN
AREA 13-EBH COMPR.
80,000
32,245
225,000
305,000
138,070
5,256
24,321
241,902
245,654
259,438
13,784
1,200
271,892
275,965
4,073
22,219
58,304
61,422
3,118
45,176
168,284
177,666
9,382
30,357
29,179
1,178
9,653
131,994
133,302
1,106
1,308
123,949
18,096
103,371
61,563
2,705
2,154
500
497
8,631
17,677
16,156
7,000
1,104
3,039
17,095
3,210
6,580
4,493
14,571
420
5,756
677,616
1,106,477
557,810
428,861
142,213
56,471
0
F30209


CASE 3: NORMAL YIELDS-NORMAL STEAM-C/C DOWN-EBH @ HIGH CONVERSION
900 PSIG
450 PSIG
150 PSIG
75 PSIG
27 PSIG
80,000
LPG COMPR.
1,500 BHP
0
225,000
305,000
- BHP
32,850 BHP
207,275
K.O. POT
4,563
BD
1,657
BOILER
TYPE MM BTU/HR
GAS 152.32 LHV
LPG 2.50 LHV
OIL 121.39 LHV
TTL 276.21 LHV
HT.ABS. 257.98
17,677
15,271
7,000
5,256
2,000 BHP
1,478 BHP
250 BHP
725 BHP
19,691
891 BHP
2,705
19,691
POWER REC. NO. 2
4,239
500
46,073
K.O.
241,902
139,574
CONSUMPTION
15=235,702
16=5,000
NHT=1,200
PRODUCTION
12=12,720
15=107,189
16=19,665
151,236
11,662
271,892
CONSUMPTION
-
PRODUCTION
12=107,480
15=164,412
275,965
4,073
14,619
37,264
CONSUMPTION
12=3,760
EBH=1,200
15=9,651
PRODUCTION
EBH=21,974
15=15,290
39,242
1,978
45,040
168,284
CONSUMPTION
12=12,098
EBH=3,300
15=29,642
PRODUCTION
12=63,969
15=104,315
177,666
9,382
551
FLASH
27,095
26,544
103,371
10,770
13,694
814 BHP
2,381
FLASH
6,580
4,493
FLASH
18,096
126,088
1,054
VENT
9,653
131,994
CONSUMPTION
15=9,653
PRODUCTION
15=131,994
133,302
1,308
DEAERATOR
P=35 PSIA
T=259.3°F
MAKE-UP
421,975
640,696
427,201
HP
1,150 PSIA
250 PSIA
LP
1,053,627
BFW
506,618
412,931
TO PROCESS
EBH=60,521
NHT=2,200
62,721
LP BFW
AREA 15
14,571
0
POWER REC. NO. 1
305,000
AREA 15-RAW GAS COMPRESSOR
13,694
POWER REC. NO. 3
HP-BFW TO BOILER
17,677
AREA 12 PUMPRESSOR
15,271
HP-BFW PUMPS
420
BOILER F.D. FAN
5,756
AREA 13-EBH COMPR.
2,705
46,073
103,371
18,096
CONDENSATE RETURN HEADER
213,495
F30210

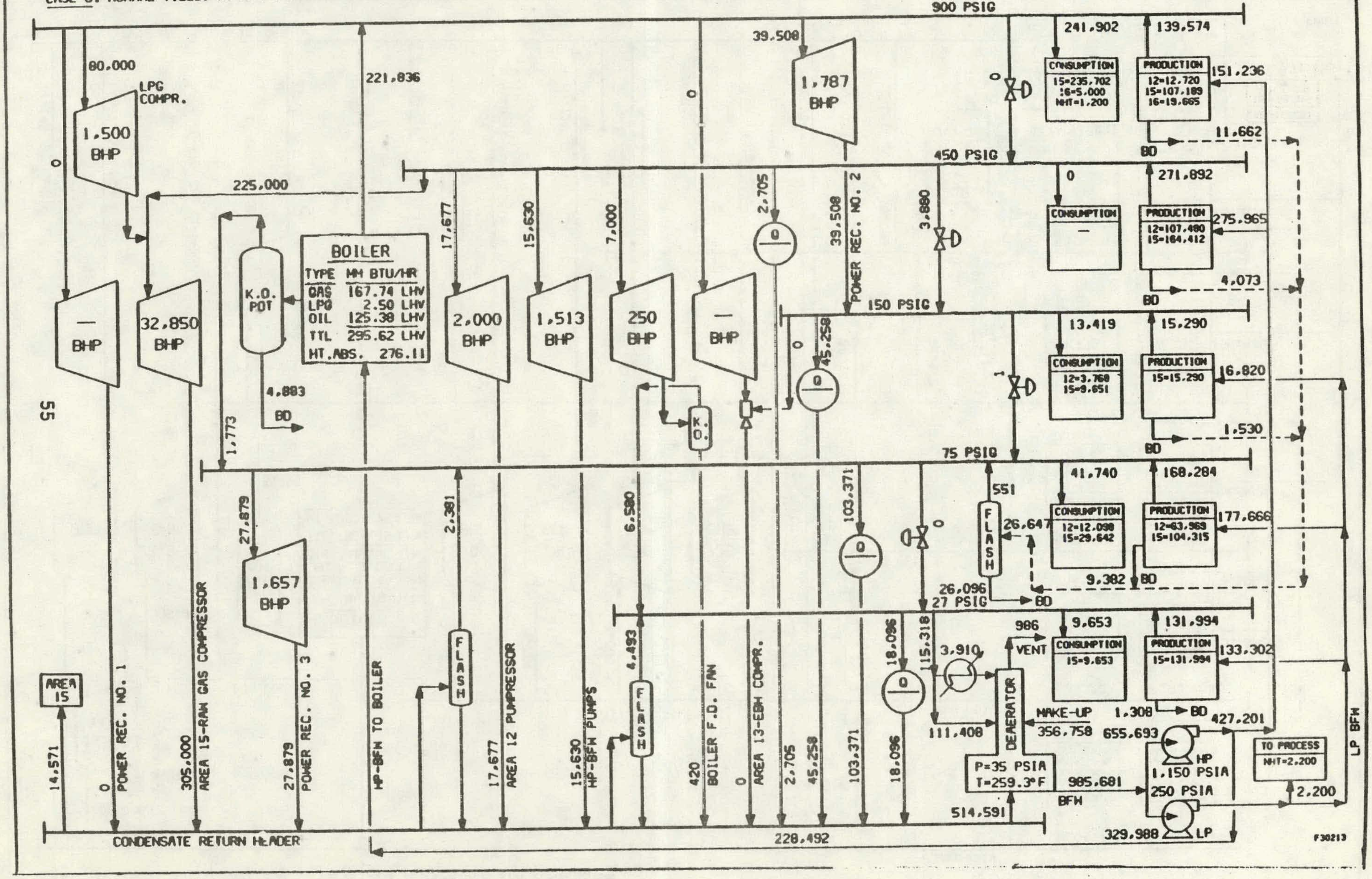


CASE 4: NORMAL YIELDS-NORMAL STEAM-C/C DOWN-EBH @ LOW CONVERSION
900 PSIG
450 PSIG
150 PSIG
75 PSIG
27 PSIG
CONDENSATE RETURN HEADER
80,000
LPG COMPR.
1,500 BHP
0
225,000
305,000
- BHP
32,850 BHP
209,069
BOILER
TYPE MM BTU/HR
GAS 196.44 LHV
LPG 2.50 LHV
OIL 79.66 LHV
TTL 278.60 LHV
HT. ABS. 260.22
K.O. POT
4,601
BD
1,672
17,677
15,319
7,000
5,256
2,000 BHP
1,483 BHP
250 BHP
725 BHP
K.O.
21,485
972 BHP
2,705
21,485
POWER REC. NO. 2
4,191
500
46,073
15,018
892 BHP
2,381
6,580
4,493
FLASH
103,371
9,509
18,096
124,827
0
241,902
139,574
CONSUMPTION
15=235,702
16=5,000
NHT=1,200
PRODUCTION
12=12,720
15=107,189
16=19,665
151,236
11,662
BD
0
271,892
CONSUMPTION
—
PRODUCTION
12=107,480
15=164,412
275,965
4,073
BD
15,419
36,316
CONSUMPTION
12=3,768
EBH=2,000
15=9,651
PRODUCTION
EBH=21,026
15=15,290
38,276
1,960
BD
551
44,990
168,284
CONSUMPTION
12=12,098
EBH=3,250
15=29,642
PRODUCTION
12=63,969
15=104,315
177,666
27,077
9,382
BD
26,526
BD
1,048
VENT
9,653
131,994
CONSUMPTION
15=9,653
PRODUCTION
15=131,994
133,302
1,308
BD
DEAERATOR
MAKE-UP
416,489
642,543
427,201
P=35 PSIA
T=259.3°F
1,048,258
BFW
HP
1,150 PSIA
250 PSIA
LP
405,715
507,990
TO PROCESS
EBH=54,271
NHT=2,200
56,471
LP BFW
AREA 15
14,571
0
POWER REC. NO. 1
305,000
AREA 15-RAW GAS COMPRESSOR
15,018
POWER REC. NO. 3
HP-BFW TO BOILER
17,677
AREA 12 PUMPRESSOR
15,319
HP-BFW PUMPS
420
BOILER F.D. FAN
5,756
AREA 13-EBH COMPR.
2,705
46,073
103,371
18,096
215,342
F30211

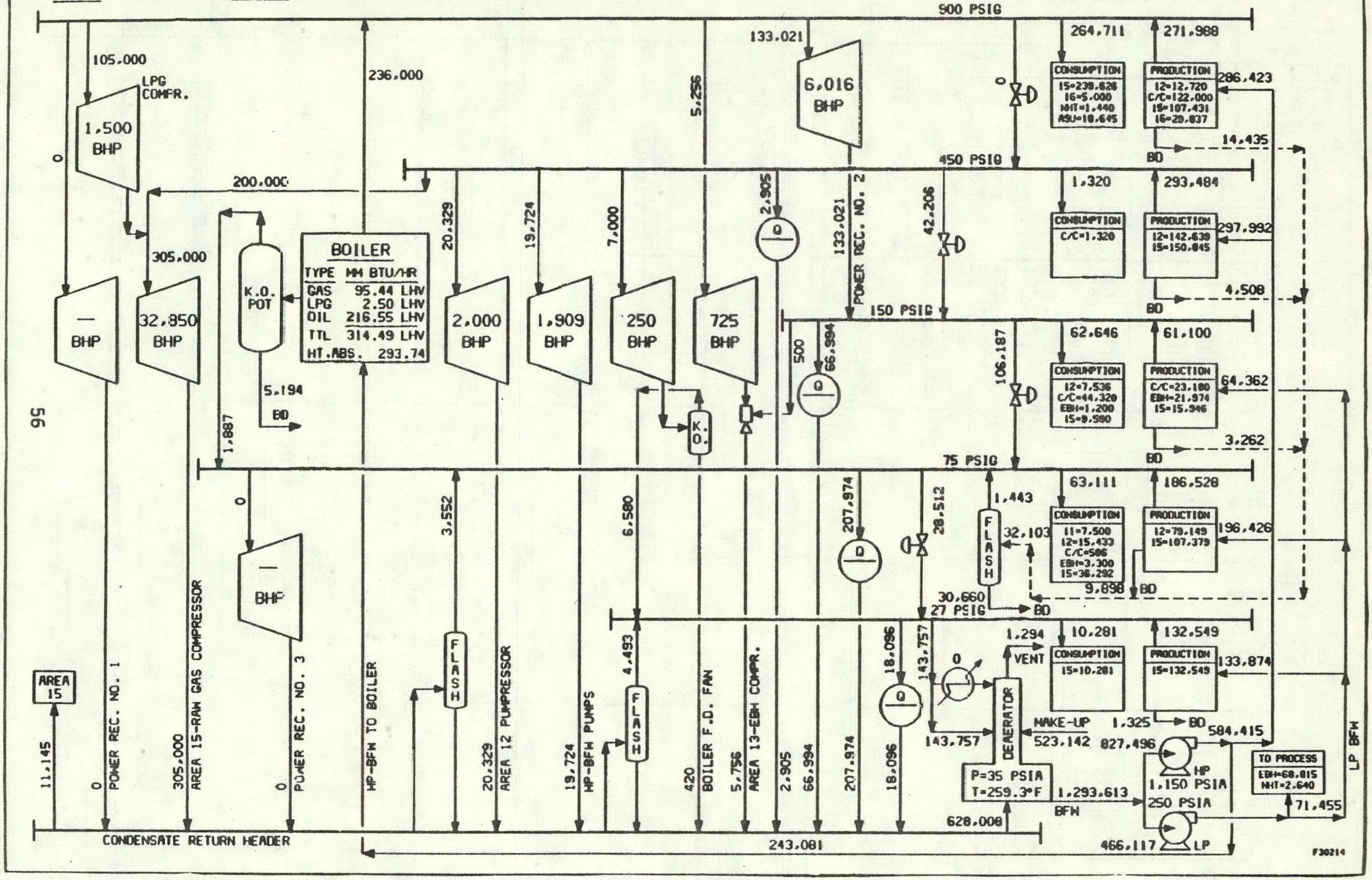
CASE 5: NORMAL YIELDS-NORMAL STEAM-EBH DOWN



CASE 6: NORMAL YIELDS-NORMAL STEAM-BOTH EBH AND C/C DOWN



CASE 7: NORMAL YIELDS-MAXIMUM STEAM-ALL UNITS UP-EBH @ LOW CONVERSION



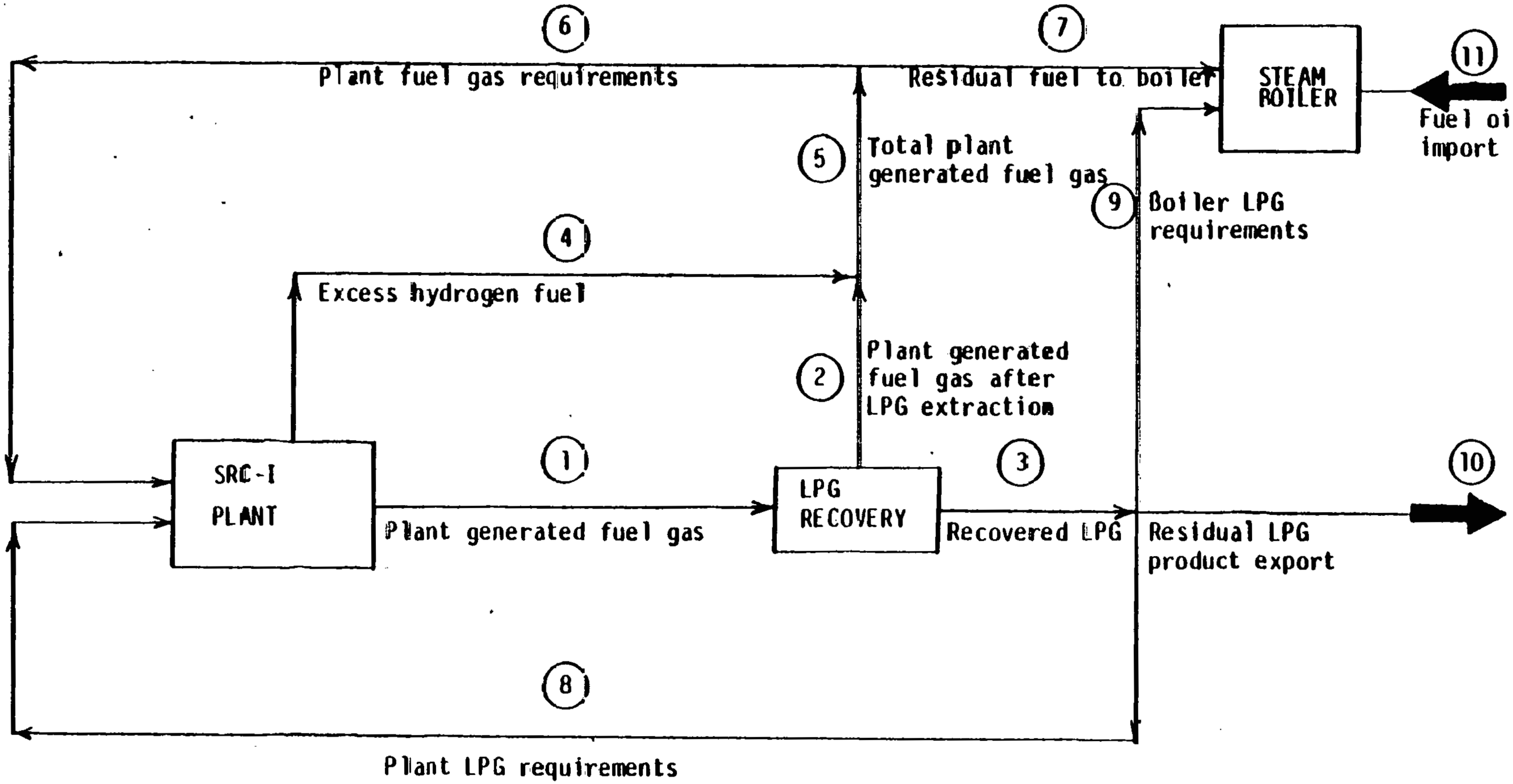
ATTACHMENT C

Baseline II

Plant Fuel Balance Diagrams

Case No. 1 NORMAL YIELDS - NORMAL STEAM - ALL UNITS UP-EBH @ HIGH CONVERSION

SRC-I PLANT FUEL BALANCE

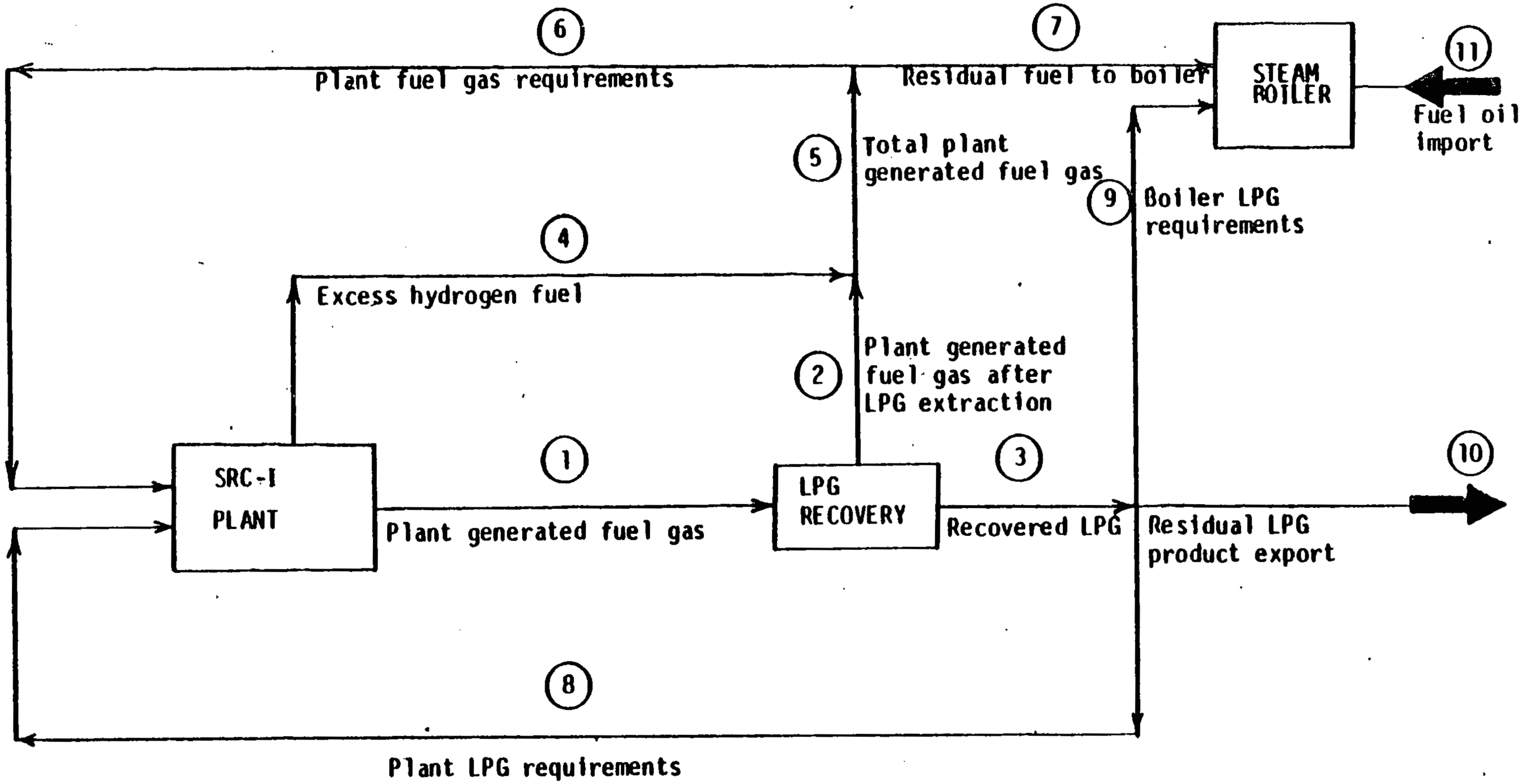


Units: All fuel values are in MMBtu/hr., LHV

POINT NO.	1	2	3	4	5	6	7	8	9	10	11
LHV MMBtu/hr.	886.24	785.48	100.76	0	785.48	643.90	141.58	22.6	2.5	75.66	0

Case No. 2 NORMAL YIELDS - NORMAL STEAM - ALL UNITS UP-EBH @ LOW CONVERSION

SRC-I PLANT FUEL BALANCE

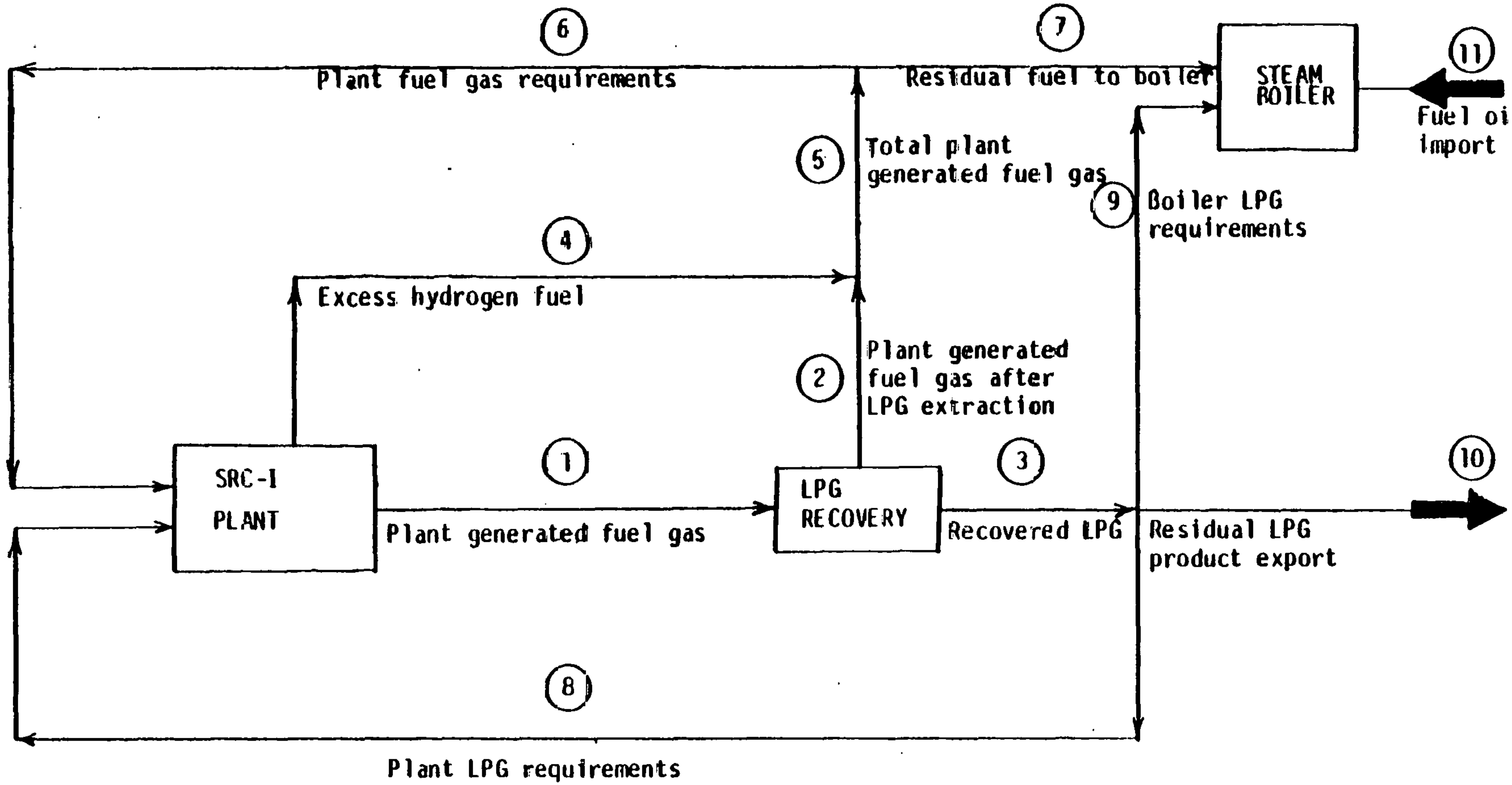


Units: All fuel values are in MMBtu/hr., LHV

POINT NO.	1	2	3	4	5	6	7	8	9	10	11
LHV MMBtu/hr.	940.94	835.89	105.05	0	835.89	654.40	181.49	22.7	2.5	79.85	0

Case No. 3 NORMAL YIELDS - NORMAL STEAM - C/C DOWN - EBH @ HIGH CONVERSION

SRC-I PLANT FUEL BALANCE

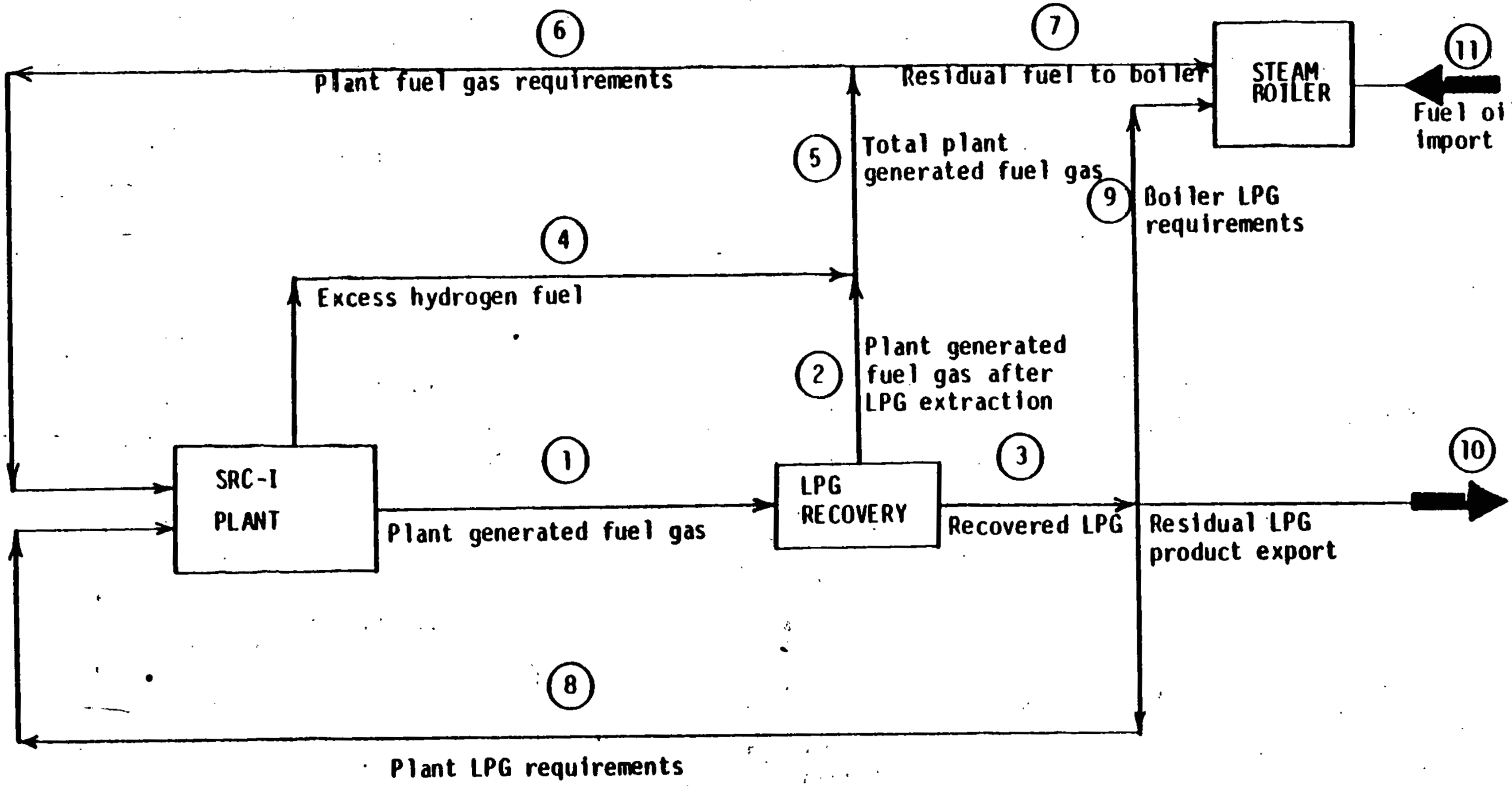


Units: All fuel values are in MMBtu/hr., LHV

POINT NO.	1	2	3	4	5	6	7	8	9	10	11
LHV MMBtu/hr.	745.32	721.02	24.3	0	721.02	568.70	152.32	21.8	2.5	0	121.39

Case No. 4 NORMAL YIELDS - NORMAL STEAM - C/C DOWN - EBH @ LOW CONVERSION

SRC-I PLANT FUEL BALANCE

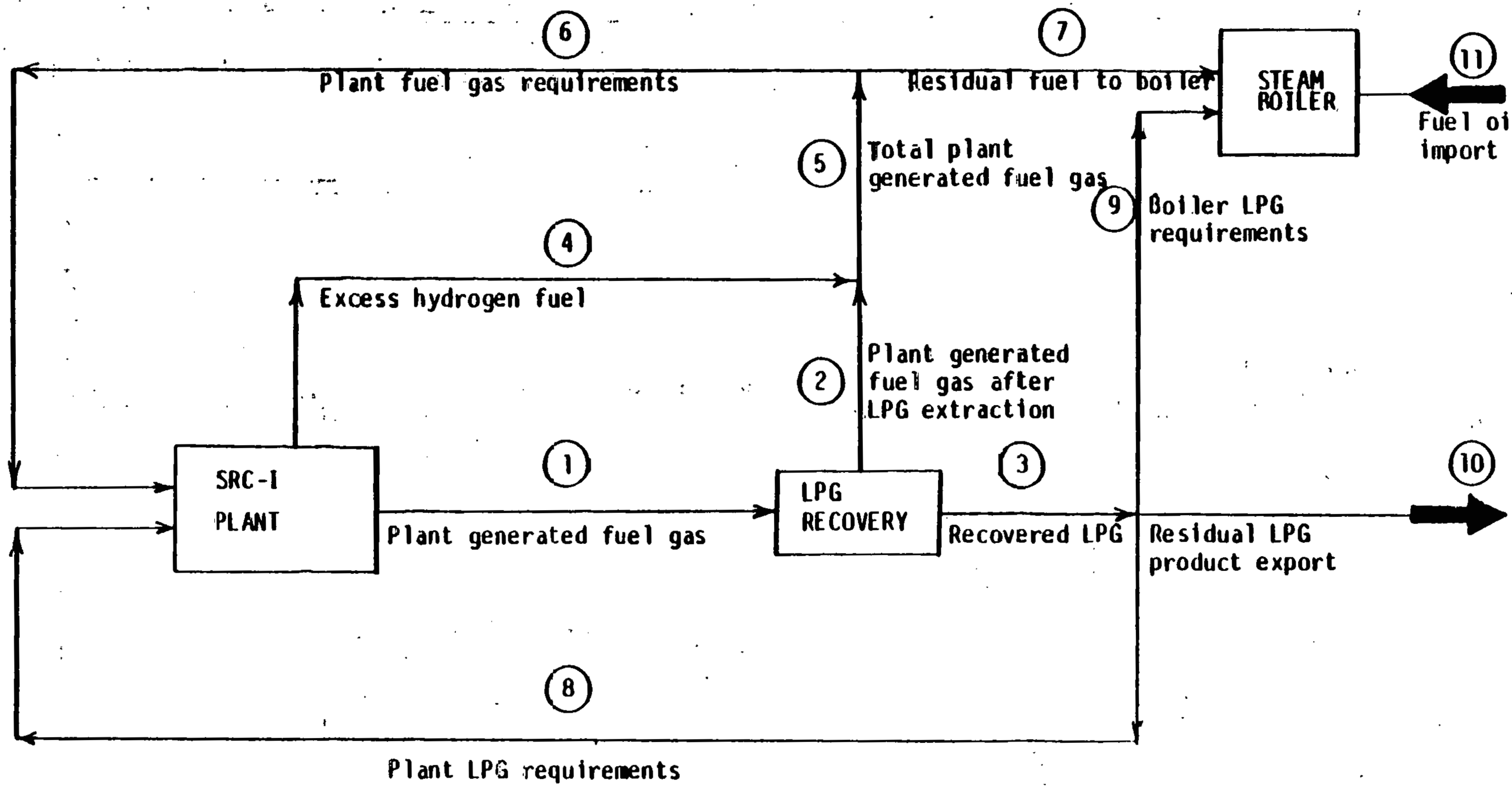


Units: All fuel values are in MMBtu/hr., LHV

POINT NO.	1	2	3	4	5	6	7	8	9	10	11
LHV MMBtu/hr.	800.04	775.64	24.4	0	775.64	579.20	196.44	21.9	2.5	0	79.66

Case No. 5 NORMAL YIELDS - NORMAL STEAM - EBH DOWN

SRC-I PLANT FUEL BALANCE

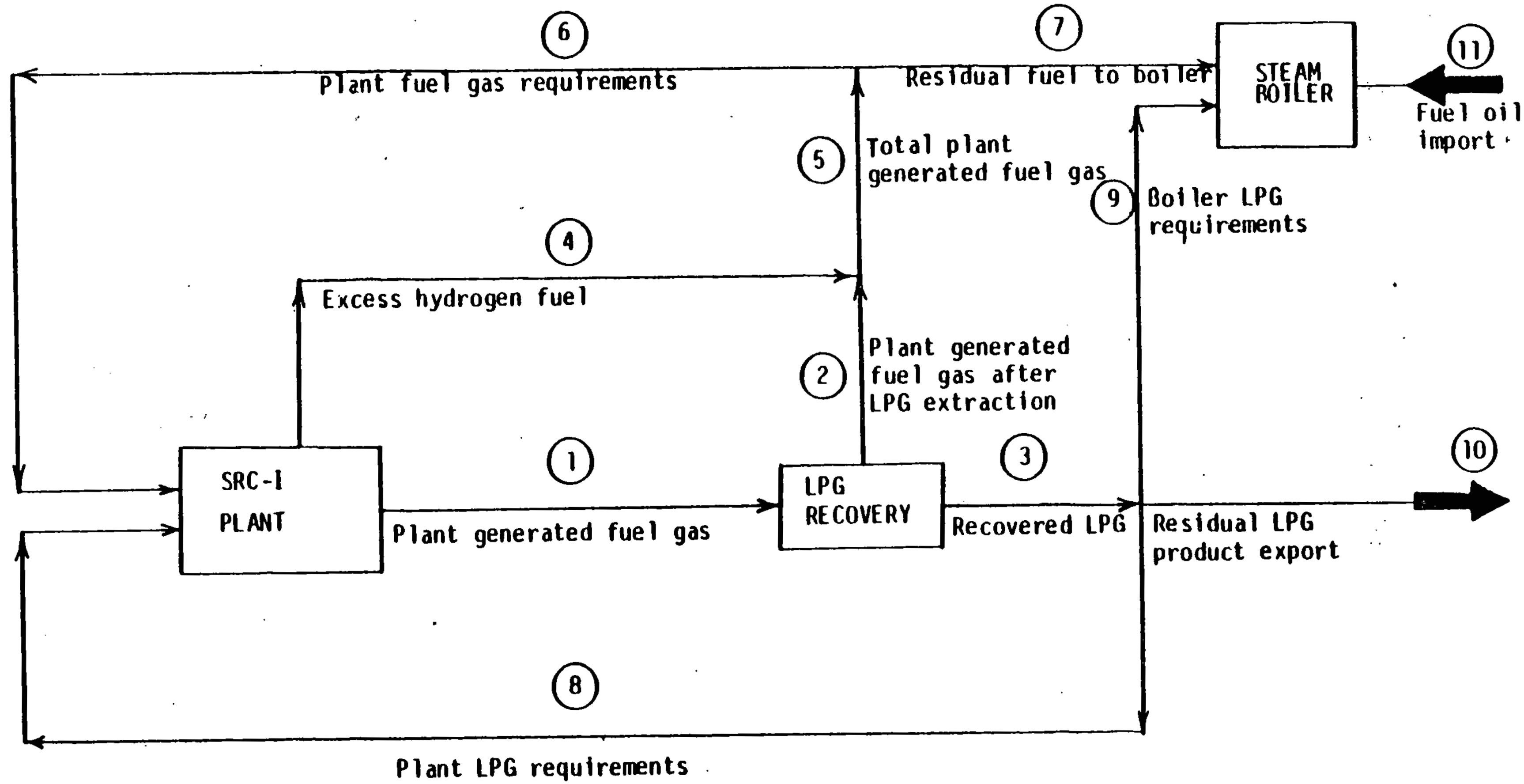


Units: All fuel values are in MMBtu/hr., LHV

POINT NO.	1	2	3	4	5	6	7	8	9	10	11
LHV MMBtu/hr.	668.22	616.60	51.62	201.52	818.12	612.30	205.82	22.3	2.5	26.82	0

Case No. 6 NORMAL YIELDS - NORMAL STEAM - EBH AND C/C DOWN

SRC-I PLANT FUEL BALANCE

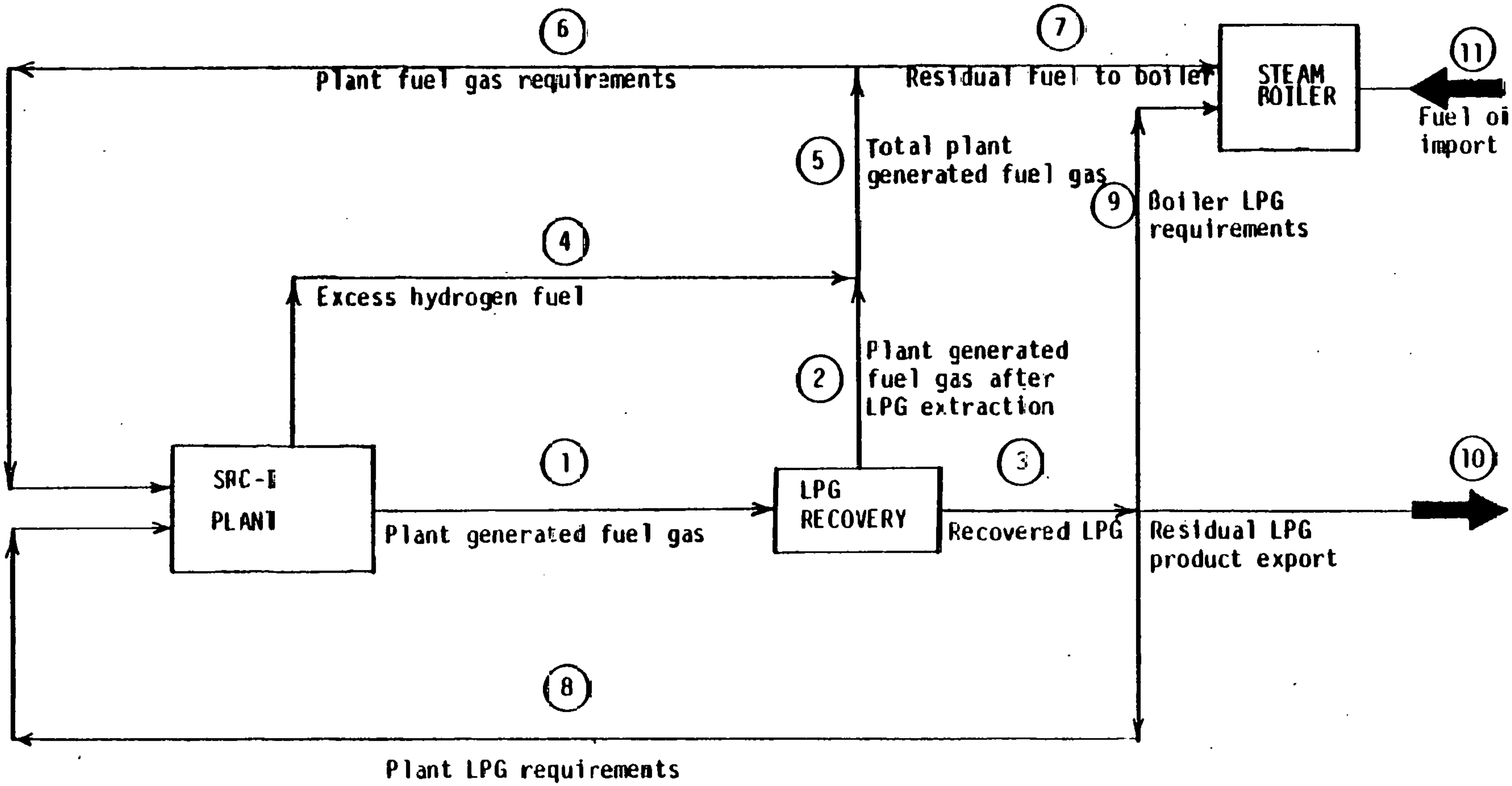


Units: All fuel values are in MMBtu/hr., LHV

POINT NO.	1	2	3	4	5	6	7	8	9	10	11
LHV MMBtu/hr.	527.32	503.32	24.0	201.52	704.84	537.10	167.74	21.5	2.5	0	125.38

Case No. 7 NORMAL YIELDS - MAXIMUM STEAM - ALL UNITS UP-EBH @ LOW CONVERSION

SRC-I PLANT FUEL BALANCE



Units: All fuel values are in MMBtu/hr., LHV

POINT NO.	1	2	3	4	5	6	7	8	9	10	11
LHV MMBtu/hr.	940.94	911.24	29.7	0	911.24	815.8	95.44	27.2	2.5	0	216.55

ATTACHMENT D

Baseline II

Steam/Fuel Requirement Summaries

Case 1: All Units Operating - Expanded-Bed Hydrocracker at High Conversion

Utility name		Fuel gas fired	LPG fuel fired	H.P. BFW	L.P. BFW	Steam import (export)						Condensate returned (required)[a]	Blowdown[b]	Internal consump.
Battery limit conditions	In: psig (min)	60	60	1,100	220	850	900	425	130	60	25	-	-	-
	psig (max)	80	80											
	°F (max)	105	180	220	220	800	Sat	Sat	Sat	Sat	Sat	-	-	-
	Out: psig (max)	-	-	1,120	240	900	950	450	150	75	30			-
	psig (min)											90	-	
	°F (max)	-	-	220	220	860	Sat	Sat	Sat	Sat	Sat	320	-	-
Area no.	Area name	MM Btu/hr	MM Btu/hr	M lb/hr										
11	Raw material, etc.	51.4	0.5	-	-	-	-	-	-	2.000	-	2.000	-	-
12	SRC-I process	423.8	4.2	122.305	64.878	(12.720)	-	(89.723)	3.768	(48.896)	-	21.126	2.620	15.866
13	Delayed coker/calciner	75.2	0.8	108.202	23.146	(106.080)	-	1.200	0.302	(1.270)	-	14.661	2.653	8.186
13	Expanded-bed hydrocracker	31.6	0.3	-	82.943	5.256	-	-	(19.459)	3.300	-	6.571	0.448	65.021
14	Cryogenic system - ASU	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Gas systems[c]	6.6	13.1	284.642	262.910	208.513	-	63.213	39.039	(14.052)	(108.738)	411.956	24.352	299.219
16	Boiler	141.58	2.5	111.365	-	(108.121)	-	-	-	(0.864)	-	-	2.380	-
16	Utilities	30.2	3.4	20.254	-	(14.665)	-	-	0.580	(0.157)	-	0.580	0.432	5.000
17	Off sites	-	-	-	-	-	-	-	-	35.000	-	35.000	-	-
TBD	Naphtha hydrotreater	25.1	0.3	-	2.200	-	1.200	-	-	-	-	-	-	3.400
	Total	785.48	25.1	646.768	436.077	(27.817)	1.200	(25.310)	24.230	(24.939)	(108.738)	491.894	32.885	396.692

[a] All Area Contractors except for Area 15. Area 15 min psig = 60.
[b] Blowdown routed to cooling water discharge inside each Area Contractor's battery limits.
[c] Includes Area 14 MPU.

Case 2: All Units Operating - Expanded-Bed Hydrocracker at Low Conversion

Utility name		Fuel gas fired	LPG fuel fired	H.P. BFW	L.P. BFW	Steam import (export)						Condensate[a] returned (required)	Blowdown[b]	Internal consump.
Battery limit conditions	In: psig (min)	60	60	1,100	220	850	900	425	130	60	25	-	-	-
	psig (max)	80	80											
	°F (max)	105	100	220	220	800	Sat	Sat	Sat	Sat	Sat	-	-	-
	Out: psig (max)	-	-	1,120	240	900	950	450	150	75	30			-
	psig (min)		-									90	-	
	°F (max)	-	-	220	220	860	Sat	Sat	Sat	Sat	Sat	320	-	-
Area no.	Area name	MM Btu/hr	MM Btu/hr	M lb/hr										
11	Raw material, etc.	51.4	0.5	-	-	-	-	-	-	2.000	-	2.000	-	-
12	SRC-I process	423.8	4.2	122.305	64.878	(12.720)	-	(89.723)	3.768	(48.896)	-	21.126	2.620	15.866
13	Delayed coker/calciner	75.2	0.8	108.202	23.146	(106.080)	-	1.200	0.302	(1.270)	-	14.661	2.653	8.186
13	Expanded-bed hydrocracker	42.1	0.4	-	74.727	5.256	-	-	(17.711)	3.250	-	6.571	0.430	59.521
14	Cryogenic system - ASU	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Gas systems[c]	6.6	13.1	284.642	262.910	208.513	-	63.213	39.039	(14.052)	(108.738)	411.956	24.352	299.219
16	Boiler	181.49	2.5	142.213	-	(138.070)	-	-	-	(1.104)	-	-	3.039	-
16	Utilities	30.2	3.4	20.254	-	(14.665)	-	-	0.580	(0.157)	-	0.580	0.432	5.000
17	Off sites	-	-	-	-	-	-	-	-	35.000	-	35.000	-	-
TBD	Naphtha hydrotreater	25.1	0.3	-	2.200	-	1.200	-	-	-	-	-	-	3.400
	Total	835.89	25.2	677.616	428.861	(57.766)	1.200	(25.310)	25.978	(25.229)	(108.738)	491.894	33.526	391.192

[a]All Area Contractors except for Area 15. Area 15 min psig = 60.
[b]Blowdown routed to cooling water discharge inside each Area Contractor's battery limits.
[c]Includes Area 14 MPU.

Case 3: Delayed Coker/Calciner Down - Expanded-Bed Hydrocracker at High Conversion

Utility name		Fuel gas fired	LPG fuel fired	H.P. BFW	L.P. BFW	Steam import (export)						Condensate[a] returned (required)	Blowdown[b]	Internal consump.
Battery limit conditions	In: psig (min)	60	60	1,100	220	850	900	425	130	60	25	-	-	-
	psig (max)	80	80											
	°F (max)	105	102	220	220	800	Sat	Sat	Sat	Sat	Sat	-	-	-
	Out: psig (max)	-	-	1,120	240	900	950	450	150	75	30			-
	psig (min)		-									90	-	
	°F (max)	-	-	220	220	860	Sat	Sat	Sat	Sat	Sat	320	-	-
Area no.	Area name	MM Btu/hr	MM Btu/hr	M lb/hr										
11	Raw material, etc.	51.4	0.5	-	-	-	-	-	-	2.000	-	2.000	-	-
12	SRC-I process	423.8	4.2	122.305	64.878	(12.720)	-	(89.723)	3.768	(48.896)	-	21.126	2.620	15.866
13	Delayed coker/calciner	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Expanded-bed hydrocracker	31.6	0.3	-	82.943	5.256	-	-	(19.459)	3.300	-	6.571	0.448	65.021
14	Cryogenic system - ASU	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Gas systems[c]	6.6	13.1	284.642	262.910	208.513	-	63.213	39.039	(14.052)	(108.738)	411.956	24.352	299.219
16	Boiler	152.32[d]	2.5	213.495	-	(207.275)	-	-	-	(1.657)	-	-	4.563	-
16	Utilities	30.2	3.4	20.254	-	(14.665)	-	-	0.580	(0.157)	-	0.580	0.432	5.000
17	Off sites	-	-	-	-	-	-	-	-	35.000	-	35.000	-	-
TBD	Naphtha hydrotreater	25.1	0.3	-	2.200	-	1.200	-	-	-	-	-	-	3.400
	Total	721.02[d]	24.3	640.696	412.931	(20.891)	1.200	(26.510)	23.928	(24.462)	(108.738)	477.233	32.415	388.506

[a] All Area Contractors except for Area 15. Area 15 min psig = 60.
[b] Blowdown routed to cooling water discharge inside each Area Contractor's battery limits.
[c] Includes Area 14 HPU.
[d] In addition, 121.39 MM Btu/hr; LHV fuel oil is fired.

Case 4: Delayed Coker/Calciner Down - Expanded-Bed Hydrocracker at Low Conversion

Utility name		Fuel gas fired	LPG fuel fired	H.P. BFW	L.P. BFW	Steam import (export)						Condensate[a] returned (required)	Blowdown[b]	Internal consump.
Battery limit conditions	In: psig (min)	60	60	1,100	220	850	900	425	130	60	25	-	-	-
	psig (max)	80	80											
	°F (max)	105	100	220	220	800	Sat	Sat	Sat	Sat	Sat	-	-	-
	Out: psig (max)	-	-	1,120	240	900	950	450	150	75	30			-
	psig (min)		-									90	-	
	°F (max)	-	-	220	220	860	Sat	Sat	Sat	Sat	Sat	320	-	-
Area no.	Area name	MM Btu/hr	MM Btu/hr	M lb/hr										
11	Raw material, etc.	51.4	0.5	-	-	-	-	-	-	2.000	-	2.000	-	-
12	SRC-I process	423.8	4.2	122.305	64.878	(12.720)	-	(89.723)	3.768	(48.896)	-	21.126	2.620	15.866
13	Delayed coker/calciner	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Expanded-bed hydrocracker	42.1	0.4	-	75.727	5.256	-	-	(17.711)	3.250	-	6.571	0.430	59.521
14	Cryogenic system - ASU	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Gas systems[c]	6.6	13.1	284.642	262.910	208.513	-	63.213	39.039	(14.052)	(108.738)	411.956	24.352	299.219
16	Boiler	196.44[d]	2.5	215.342	-	(209.069)	-	-	-	(1.672)	-	-	4.601	-
16	Utilities	30.2	3.4	20.254	-	(14.665)	-	-	0.580	(0.157)	-	0.580	0.432	5.000
17	Off sites		-	-	-	-	-	-	-	35.000	-	35.000	-	-
TBD	Naphtha hydrotreater	25.1	0.3	-	2.200	-	1.200	-	-	-	-	-	-	3.400
	Total	775.64[d]	24.4	642.543	405.715	(22.685)	1.200	(26.510)	25.676	(24.527)	(108.738)	477.233	32.435	383.006

[a] All Area Contractors except for Area 15. Area 15 min psig = 60.
[b] Blowdown routed to cooling water discharge inside each Area Contractor's battery limits.
[c] Includes Area 14 BPU.
[d] In addition, 79.66 MM Btu/hr; LHV fuel oil is fired.

Case 5: Expanded-Bed Hydrocracker Down

Utility name		Fuel gas fired	LPG fuel fired	H.P. BFW	L.P. BFW	Steam import (export)						Condensate returned (required)[a]	Blowdown[b]	Internal consump.
Battery limit conditions	In: psig (min)	60	60	1,100	220	850	900	425	130	60	25	-	-	-
	psig (max)	80	80											
	°F (max)	105	100	220	220	800	Sat	Sat	Sat	Sat	Sat	-	-	-
	Out: psig (max)	-	-	1,120	240	900	950	450	150	75	30			-
	psig (min)		-									90	-	
	°F (max)	-	-	220	220	860	Sat	Sat	Sat	Sat	Sat	320	-	-
Area no.	**Area name**	**MM Btu/hr**	**MM Btu/hr**	**M lb/hr**										
11	Raw material, etc.	51.4	0.5	-	-	-	-	-	-	2.000	-	2.000	-	-
12	SRC-I process	423.8	4.2	122.305	64.873	(12.720)	-	(89.723)	3.763	(48.896)	-	21.126	2.620	15.866
13	Delayed coker/calciner	75.2	0.8	108.202	23.145	(106.080)	-	1.200	0.302	(1.270)	-	14.661	2.653	8.186
13	Expanded-bed hydrocracker	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Cryogenic system - ASU	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Gas systems[c]	6.6	13.1	284.642	262.910	208.513	-	63.213	39.033	(14.052)	(108.738)	411.956	24.352	299.219
16	Boiler	205.82	2.5	161.019	-	(156.328)	-	-	-	(1.041)	-	-	3.650	-
16	Utilities	30.2	3.4	20.254	-	(14.665)	-	-	0.580	(0.157)	-	0.580	0.432	5.000
17	Off sites	-	-	-	-	-	-	-	-	35.000	-	35.000	-	-
TBD	Naphtha hydrotreater	25.1	0.3	-	2.200	-	1.200	-	-	-	-	-	-	3.400
	Total	818.12	24.8	750.745	353.134	(134.021)	1.200	(25.310)	43.683	(29.047)	(108.738)	485.323	34.658	331.671

[a] All Area Contractors except for Area 15. Area 15 min psig = 16.
[b] Blowdown routed to cooling water discharge inside each Area Contractor's battery limits.
[c] Includes Area 14 HPU.

Case 6: Expanded Bed Hydrocracker and Delayed Coker/Calciner Down

Utility name		Fuel gas fired	LPG fuel fired	H.P. BFW	L.P. BFW	Steam import (export)						Condensate[a] returned (required)	Blowdown[b]	Internal consump.
Battery limit conditions	In: psig (min)	60	60	1,100	220	850	900	425	130	60	25	-	-	-
	psig (max)	80	80											
	°F (max)	105	100	220	220	800	Sat	Sat	Sat	Sat	Sat	-	-	-
	Out: psig (max)	-	-	1,120	240	900	950	450	150	75	30			-
	psig (min)		-									90	-	
	°F (max)	-	-	220	220	860	Sat	Sat	Sat	Sat	Sat	320	-	-
Area no.	Area name	MM Btu/hr	MM Btu/hr	M lb/hr										
11	Raw material, etc.	51.4	0.5	-	-	-	-	-	-	2.000	-	2.000	-	-
12	SRC-I process	423.8	4.2	122.305	64.878	(12.720)	-	(89.723)	3.768	(48.896)	-	21.126	2.620	15.866
13	Delayed coker/calciner	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Expanded-bed hydrocracker	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Cryogenic system - ASU	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Gas systems[c]	6.6	13.1	284.642	262.910	208.513	-	63.213	39.039	(14.052)	(108.738)	411.956	24.352	299.219
16	Boiler	167.74[d]	2.5	228.492	-	(221.836)	-	-	-	(1.773)	-	-	4.883	-
16	Utilities	30.2	3.4	20.254	-	(14.665)	-	-	0.580	(0.157)	-	0.580	0.432	5.000
17	Off sites	-	-	-	-	-	-	-	-	35.000	-	35.000	-	-
TBD	Naphtha hydrotreater	25.1	0.3	-	2.200	-	1.200	-	-	-	-	-	-	3.400
	Total	704.84[d]	24.0	642.543	329.988	(27.941)	1.200	(26.510)	43.387	(27.777)	(108.738)	470.662	32.005	323.485

[a]All Area Contractors except for Area 15. Area 15 min psig = 60.
[b]Blowdown routed to cooling water discharge inside each Area Contractor's battery limits.
[c]Includes Area 14 HPU.
[d]In addition, 125.38 MM Btu/hr; LHV fuel oil is fired.

Case 7: All Units Operating - Maximum Steam Production & Requirements

Utility name		Fuel gas fired	LPG fuel fired	H.P. BFW	L.P. BFW	Steam import (export)						Condensate[a] returned (required)	Blowdown[b]	Internal consump.
Battery limit conditions	In: psig (min)	60	60	1,100	220	850	900	425	130	60	25	-	-	-
	psig (max)	80	80											
	°F (max)	105	300	220	220	800	Sat	Sat	Sat	Sat	Sat	-	-	-
	Out: psig (max)	-	-	1,120	240	900	950	450	150	75	30			-
	psig (min)		-									90	-	
	°F (max)	-	-	220	220	860	Sat	Sat	Sat	Sat	Sat	320	-	-
Area no.	Area name	MM Btu/hr	MM Btu/hr	M lb/hr										
11	Raw material, etc.	68.3	0.5	-	-	-	-	-	-	9.500	-	2.000	-	7.500
12	SRC-I process	518.4	5.2	158.036	80.273	(12.720)	-	(122.230)	7.536	(60.835)	-	23.778	3.313	22.969
13	Delayed coker/calciner	75.7	0.8	124.440	24.400	(122.000)	-	1.520	40.062	(1.187)	-	18.065	2.944	46.226
13	Expanded-bed hydrocracker	72.4	0.7	-	91.237	5.256	-	-	(19.459)	3.300	-	6.571	0.448	73.315
14	Cryogenic system - ASU	-	-	-	-	18.645	-	-	-	-	-	-	-	18.645
15	Gas systems[c]	6.6	16.3	271.206	267.567	237.195	-	51.780	40.321	5.023	(108.665)	432.870	24.623	306.934
16	Boiler	95.44[d]	2.5	243.081	-	(236.000)	-	-	-	(1.887)	-	-	5.194	-
16	Utilities	44.3	3.4	30.733	-	(24.837)	-	-	0.580	23.761	-	24.580	0.657	5.000
17	Off sites	-	-	-	-	-	-	-	-	100.000	-	100.000	-	-
TBD	Naphtha hydrotreater	30.1	0.3	-	2.640	-	1.440	-	-	-	-	-	-	4.080
	Total	911.24[d]	29.7	827.496	466.117	(134.461)	1.440	(68.930)	69.040	77.675	(108.665)	607.864	37.179	484.669

[a] All Area Contractors except for Area 15. Area 15 min psig = 60.
[b] Blowdown routed to cooling water discharge inside each Area Contractor's battery limits.
[c] Includes Area 14 HPU.
[d] In addition, 216.55 MM Btu/hr; LHV fuel oil is fired.

ATTACHMENT E

Baseline II

Plant Fuel Gas Composition Summaries

Fuel Gas Composition

Case 1: All Units Operating, Normal Fuel Yield
(Expanded-Bed Hydrocracker at High Conversion)

	Gross fuel (vol %)	Maximum LPG recovery (vol %)	LPG fuel[a] (vol %)	Net fuel[b] (vol %)
H_2	18.02	-	-	18.89
N_2	6.61	-	-	6.93
AR	0.75	-	-	0.79
CO	6.99	-	-	7.33
CH_4	39.37	-	-	41.27
C_2H_6	14.38	0.70	0.70	15.05
C_3H_8	7.50	63.16	63.16	4.80
C_4H_{10}	4.60	35.29	35.29	3.11
C_5H_{12}	1.10	0.85	0.85	1.11
C_6 → 250°F	0.55	-	-	0.58
250°F → 350°F	0.03	-	-	0.03
CO_2	0.10	-	-	0.11
	100.00	100.00	100.00	100.00
MM scfd	20.34	0.94	0.23	19.40
MM Btu/hr	886.24	100.76	25.10	785.48
LHV, Btu/scf	1,045.5	2,567.9	2,567.9	971.6

[a]LPG (25.10 MM Btu/hr) fuel is required for gas systems (Area 15) constant heating value burners and plant pilot system.
[b]LPG (75.66 MM Btu/hr) is recovered as a demonstration plant product; the net fuel should be used as the base fuel for this operating mode.

Fuel Gas Composition

Case 2: All Units Operating, Normal Fuel Yield
(Expanded-Bed Hydrocracker at Low Conversion)

	Gross fuel (vol %)	Maximum LPG recovery (vol %)	LPG fuel[a] (vol %)	Net fuel[b] (vol %)
H_2	16.24	-	-	17.04
N_2	6.40	-	-	6.71
AR	0.73	-	-	0.76
CO	6.76	-	-	7.09
CH_4	40.56	-	-	42.57
C_2H_6	14.84	0.70	0.70	15.53
C_3H_8	7.82	63.80	63.80	5.08
C_4H_{10}	4.89	34.57	34.57	3.43
C_5H_{12}	1.09	0.93	0.93	1.10
C_6 → 250°F	0.54	-	-	0.56
250°F → 350°F	0.03	-	-	0.03
CO_2	0.10	-	-	0.10
	100.00	100.00	100.0	100.00
MM scfd	21.04	0.98	0.24	20.06
MM Btu/hr	940.94	105.05	25.20	835.89
LHV, Btu/scf	1,073.3	2,563.9	2,563.9	1,000.2

[a]LPG (25.20 MM Btu/hr) fuel is required for Gas Systems (Area 15) constant heating value burners and plant pilot system.

[b]LPG (79.85 MM Btu/hr) is recovered as a demonstration plant product; the net fuel should be used as the base fuel for this operating mode.

Fuel Gas Composition

Case 3: Delayed Coker/Calciner Down, Normal Fuel Yield
(Expanded-Bed Hydrocracker at High Conversion)

	Gross fuel (vol %)	Maximum LPG recovery (vol %)	LPG fuel[a] (vol %)	Net fuel[b] (vol %)
H_2	18.63	-	-	18.87
N_2	7.75	-	-	7.85
AR	0.88	-	-	0.89
CO	7.91	-	-	8.02
CH_4	36.15	-	-	36.63
C_2H_6	14.26	0.70	0.70	14.44
C_3H_8	7.77	63.16	63.16	7.04
C_4H_{10}	5.03	35.29	35.29	4.63
C_5H_{12}	1.03	0.85	0.85	1.03
C_6 → 250°F	0.49	-	-	0.50
250°F → 350°F	nil	-	-	nil
CO_2	0.10	-	-	0.10
	100.00	100.00	100.0	100.00
MM scfd	17.36	0.94	0.23	17.14
MM Btu/hr	745.32	100.76	24.30	721.02
LHV, Btu/scf	1,030.3	2,567.9	2,567.9	1,009.9

[a]LPG (24.30 MM Btu/hr) is recovered for use in gas systems (Area 15) constant heating value burners and plant pilot system.

[b]The remaining LPG (76.46 MM Btu/hr) is not recovered and remains in the net plant fuel; the net fuel should be used as the base fuel for this operating mode.

Fuel Gas Composition

Case 4: Delayed Coker/Calciner Down, Normal Fuel Yield (Expanded-Bed Hydrocracker at Low Conversion)

	Gross fuel (vol %)	Maximum LPG recovery (vol %)	LPG fuel[a] (vol %)	Net fuel[b] (vol %)
H_2	16.54	-	-	16.75
N_2	7.45	-	-	7.55
AR	0.85	-	-	0.86
CO	7.61	-	-	7.71
CH_4	37.68	-	-	38.17
C_2H_6	14.79	0.70	0.70	14.97
C_3H_8	8.14	63.80	63.80	7.42
C_4H_{10}	5.34	34.57	34.57	4.97
C_5H_{12}	1.02	0.93	0.93	1.02
C_6 → 250°F	0.48	-	-	0.48
250°F → 350°F	nil	-	-	nil
CO_2	0.10	-	-	0.10
	100.00	100.00	100.00	100.00
MM scfd	18.06	0.98	0.23	17.83
MM Btu/hr	800.04	105.05	24.40	775.64
LHV, Btu/scf	1,063.2	2,563.9	2,563.9	1,043.9

[a]LPG (24.40 MM Btu/hr) is recovered for use in gas systems (Area 15) constant heating value burners and plant pilot system.

[b]The remaining LPG (80.65 MM Btu/hr) is not recovered and remains in the net plant fuel; the net fuel should be used as the base fuel for this operating mode.

Fuel Gas Composition

Case 5: Expanded Bed Hydrocracker Down, Normal Fuel Yield

	Generated fuel gas (vol %)	Maximum LPG recovery (vol %)	LPG fuel[a] (vol %)	H_2 blend fuel (vol %)	Net fuel gas[b,c] (vol %)
H_2	35.08	-	-	95.67	65.54
N_2	3.10	-	-	0.97	2.09
AR	0.63	-	-	0.20	0.43
CO	8.68	-	-	2.95	5.96
CH_4	31.11	-	-	0.11	16.20
C_2H_6	12.06	0.28	0.28	-	6.25
C_3H_8	5.24	71.55	71.55	-	1.74
C_4H_{10}	2.51	26.70	26.70	-	0.94
C_5H_{12}	0.96	1.48	1.48	-	0.48
C_6 → 250°F	0.49	-	-	-	0.25
250 → 350°F	0.04	-	-	-	0.02
CO_2	0.10	-	-	0.10	0.10
	100.00	100.00	100.00	100.00	100.00
MM scfd	18.61	0.49	0.24	17.74	35.86
MM Btu/hr	668.22	51.62	24.80	201.52	818.12
LHV, Btu/scf	861.8	2,519.9	2,519.9	272.6	547.5

[a]LPG fuel (24.80 MM Btu/hr) is required for gas systems (Area 15) constant heating value burners and plant pilot system.
[b]LPG will be recovered as product (26.82 MM Btu/hr).
[c]Net fuel gas = generated fuel gas - recovered LPG + H_2 blend fuel
= 668.22 - (24.80 + 26.82) + 201.52
= 818.12 MM Btu/hr.

Fuel Gas Composition

Case 6: Expanded Bed Hydrocracker & Delayed Coker/Calciner Down, Normal Fuel Yield

	Generated fuel gas (vol %)	Maximum LPG recovery (vol %)	LPG fuel[a] (vol %)	H_2 Blend fuel (vol %)	Net fuel gas[b,c] (vol %)
H_2	39.01	-	-	95.67	69.62
N_2	3.69	-	-	0.97	2.26
AR	0.75	-	-	0.20	0.46
CO	10.03	-	-	2.95	6.31
CH_4	25.97	-	-	0.11	12.30
C_2H_6	11.48	0.28	0.28	-	5.41
C_3H_8	5.11	71.54	71.54	-	1.92
C_4H_{10}	2.59	26.70	26.70	-	1.04
C_5H_{12}	0.86	1.48	1.48	-	0.39
C_6 → 250°F	0.41	-	-	-	0.19
250 → 350°F	nil	-	-	-	nil
CO_2	0.10	-	-	0.10	0.10
	100.00	100.00	100.00	100.00	100.00
MM scfd	15.63	0.49	0.23	17.74	33.15
MM Btu/hr	527.32	51.62	24.00	201.52	704.84
LHV, Btu/scf	809.7	2,519.9	2,519.9	272.6	510.4

[a]LPG fuel (24.00 MM Btu/hr) is required for gas systems (Area 15) constant heating value burners and plant pilot system.

[b]The remaining LPG (27.62 MM Btu/hr) is not recovered and remains in the net fuel gas.

[c]Net fuel gas = generated fuel - recovered LPG + H_2 blend fuel gas.
= 527.32 - 24.00 + 201.52
= 704.84 MM Btu/hr

Fuel Gas Composition

Case 7: All Units Operating, Normal Fuel Yield

(Maximum Steam Production & Requirements,
Expanded Bed Hydrocracker at Low Conversion

	Gross fuel (vol %)	Maximum LPG recovery (vol %)	LPG fuel[a] (vol %)	Net fuel[b] (vol %)
H_2	16.24	-	-	16.46
N_2	6.40	-	-	6.48
AR	0.73	-	-	0.74
CO	6.76	-	-	6.85
CH_4	40.56	-	-	41.11
C_2H_6	14.84	0.70	0.70	15.02
C_3H_8	7.82	63.80	63.80	7.07
C_4H_{10}	4.89	34.57	34.57	4.49
C_5H_{12}	1.09	0.93	0.93	1.10
$C_6 \rightarrow 250°F$	0.54	-	-	0.55
250°F → 350°F	0.03	-	-	0.03
CO_2	0.10	-	-	0.10
	100.00	100.00	100.00	100.00
MM scfd	21.04	0.98	0.28	20.76
MM Btu/hr	940.94	105.05	29.70	911.24
LHV, Btu/scf	1,073.3	2,563.90	2,563.90	1,053.3

[a]LPG (29.70 MM Btu/hr) is required for Gas Systems (Area 15) heating value burners and plant pilot system.

[b]The remaining LPG (75.35 MM Btu/hr) is not recovered and remains in the net plant fuel; the net fuel should be used as the base fuel for this case.

Fuel Gas Composition

Start-Up H_2 Fuel[a]

	Maximum Hydrogen[b] (vol %)
H_2	95.67
N_2	0.97
AR	0.20
CO	2.95
CH_4	0.11
C_2H_6	-
C_3H_8	-
C_4H_{10}	-
C_5H_{12}	-
C_6 → 250°F	-
250°F → 350°F	-
CO_2	0.10
	100.00
MM scfd	52.0
MM Btu/hr	591.0
LHV, Btu/scf	272.6

[a] H_2 fuel is distributed to the boiler (Area 16) and slurry heaters (Area 12) only.
[b] During start-up phase, hydrogen will be available for use as fuel up to the maximum amount given above.

FUEL OIL SPECIFICATION

No. 2 fuel oil will be available as start-up and emergency backup plant fuel.

Specification

Gravity, °API	28 to 10	
Volatility		
Flash point, °F, min., (D93)+		150 to 200
Distillation	540 to 640	
Elemental analysis, wt %		
Carbon	86.1 to 88.2	
Hydrogen	11.8 to 13.9	
Oxygen	--	
Nitrogen	Nil to 0.1	
Sulfur	0.5	
Ash	--	
Viscosity, SSU at 100°F, min., (D445)+		32 to 38
Metals, ppm (wt) max. (D2788)+		
Vanadium	2.0	
Sodium		
Potassium	5.0	
Calcium	10.0	
Lead	5.0	
HHV, Btu/lb	19,170 to 19,750	
LVH, Btu/lb	18,000 to 18,600	