2. INDIRECT LIQUEFACTION WITH LURGI GASIFICATION AND FISCHER-TROPSCH TECHNOLOGIES

This section addresses coal-based synthetic fuels facilities using dry ash Lurgi gasification and Fischer-Tropsch (F-T) product synthesis. Facilities of this type utilize all of the process operations normally associated with indirect liquefaction, namely coal preparation, coal gasification and raw gas cleaning, shift conversion and acid gas removal, and synthesis of the desired fuel product. Auxiliary processes required to support these production operations are those required for steam and power generation, oxygen production, raw water treatment, and process cooling.

The dry ash Lurgi process is a commercially viable process which has been widely used outside the U.S. to produce industrial fuel gas and synthesis gas from coal. To date, the Lurgi gasifier has been used primarily to gasify low rank coals. The technology has demonstrated the capability to handle highly caking coals such as those used during the trials of American coals at Westfield, Scotland (1) and at SASOL, where a Kentucky No. 9 coal was gasified (2). Companion technologies have also been developed for gas cooling/heat recovery, gas liquor treatment, acid gas removal, and by-product (tar, oil, naphtha, phenol, and ammonia) recovery. Of the commercial facilities in operation, only those operated by the South African Coal, Oil, and Gas Corp., Ltd. (SASOL) are representative of the completely integrated facilities (i.e., coal gasification and product synthesis) addressed in this report. The SASOL facilities produce a wide range of crude and refined liquid products utilizing Fisher-Tropsch technology as the primary product synthesis step.

A wide variety of domestic coals are potential feedstocks for Lurgi based synthetic fuels facilities. Each coal will have associated with its use a specific set of process and waste stream characteristics. The most advanced Lurgi based synfuels project in the U.S. is the Great Plains Gasi-fication Associates' project in North Dakota which will be using a lignite

2-1

TABLE 2-1. CHARACTERISTICS OF DUNN LIGNITE SELECTED FOR USE IN INDIRECT
LIQUEFACTION BASE PLANT (4,5)

	As Revised Basis (wt %)	Dry Bases (wt %)
Moisture	38.6	
Volatile Matter	27.0	
Fixed Carbon	27.6	
Ash	6.8	11.1
C	39.1	63.6
H	2.7	4.4
O	11.6	18.9
S	0.8	1.3
N	0.4	0.6
Heating Value		
MJ/kg	15.0	24.5

Major and Minor Elements in Coal
(%, on moisture-free whole coal basis)

Al	0.67	Mg	0.50
Ca	1.6	Na	0.24
Cl	0.005	Si	2.2
Fe	0.72	Ti	0.03
K	0.005		

Trace Elements
(ppm, on moisture-free whole coal basis)

As	16	Hg	0.33
B	100	Mo	36
Be	0.50	Mn	400
Br	2.8	Ni	19
Cd	0.34	P	213
Co	8	Pb	88
Ce	100	Sb	0.50
Cu	37	Se	1.4
F	34	Zn	18
Ge	0.98		

feed coal (3). Thus, a North Dakota lignite (Dunn County) was chosen for examination to provide a basis for sizing and characterizing base plant process and waste streams and evaluating waste stream control options. Characterization data for the Dunn lignite are presented in Table 2-1.

In developing the base plant material flow estimates, a fixed coal feed rate of 27,216 Mg per day (as received basis) to gasification was used. In addition to the gasifier coal requirements, most Lurgi based synfuels facilities are expected to include on-site coal fired auxiliary boilers. The size, and hence fuel requirements, of these boilers will depend on a variety of factors, including whether electric power is purchased or generated onsite, the efficiency of on-site energy recovery, and whether Lurgi by-products and high energy content waste gases are used as boiler fuel. Although no attempt has been made to estimate auxiliary boiler duties, boiler energy requirements are expected to be about 30 percent of the coal energy input to the gasifier (6,7,8).

A typical upgraded product slate for the Lurgi based synfuels plant examined in this study is summarized in Table 2-2. It should be noted that large quantities of methane are present in Lurgi synthesis gas. It is assumed that this methane would be recovered as a coproduct SNG rather than reformed to produce additional synthesis gas.

TABLE 2-2. ESTIMATED PRODUCT/BY-PRODUCT SLATE FOR LURGI BASED F-T SYNFUEL FACILITY*

Product/By-Product	Mg/day	TJ/day
Gasoline	1340	62.5
Diesel Oil	272	11.4
Fuel Oil	79.6	2.8
LPG	101	8.50
SNG	3700	186
Alcohols	230	8.5
TOTAL	5720	280

*Coal feed rate to gasification is 27,216 Mg/day (as received basis). In addition to the tabulated products and by-products, tars, oils, naphthas and phenols are also produced and consumed onsite.

2-3

2.1 BASED PLANT DESCRIPTION

Based plant process operations consist of coal preparation, coal gasifi-
cation, gas purification and upgrading, crude product synthesis and separa-
tion, and product upgrading. In addition, the auxiliary processes required
to support a fully integrated, self-sufficient, liquid fuels production
facility would include raw water treatment, steam and power generation, and
oxygen production. Pollution control process applicable to the base plant
are described and discussed subsequently in Section 2.2. Processes comprising
the base plant and their associated waste streams are described briefly in
this section. Simplified process flow diagrams are presented in Figures 2-1,
2-2, 2-3, and 2-4.

2.1.1 Coal Preparation

The coal preparation operation in a Lurgi based synfuels facility will
be similar to those found in other coal based plants such as coal fired
power plants. Equipment is provided to receive, transport, and store coal
and to prepare a sized coal feed for the Lurgi gasifiers and a pulverized
coal feed for on-site coal fired steam boilers.

Run-of-mine coal received by conveyor, unit train, barge, or truck is
diverted to either an active or inactive (emergency) storage pile as neces-
sary. Coal from storage is transported by a belt conveyor to the preparation
plant where it is screened and crushed to a 3.8 cm top size. A 3.8 cm x
0.64 cm coal fraction is separated and conveyed to the gasifier feed storage
silos. (Depending on the properties of the coal, a sized coal within the
range of 0.3 cm to 7.5 cm can be gasified; the 3.8 cm x 0.64 cm range shown
is merely a representative example.) The undersize coal is stored in separate
fine coal storage silos. As required to meet the auxiliary steam boiler fuel
requirements, coal is removed from the fine coal storage silos and pulverized
to nominally 70 percent through 200 mesh. Excess undersized coal may or may
not be produced, depending on t / feed coal characteristics. If excess
undersized coal is produced, it could be used to generate export power, gasi-
fied in a reactor capable of handling coal fines to produce additional syn-
thesis gas, sold as a by-product, or disposed of as a solid waste. A poten-
tial, but currently undemonstrated, alternative is to pelletize the under-
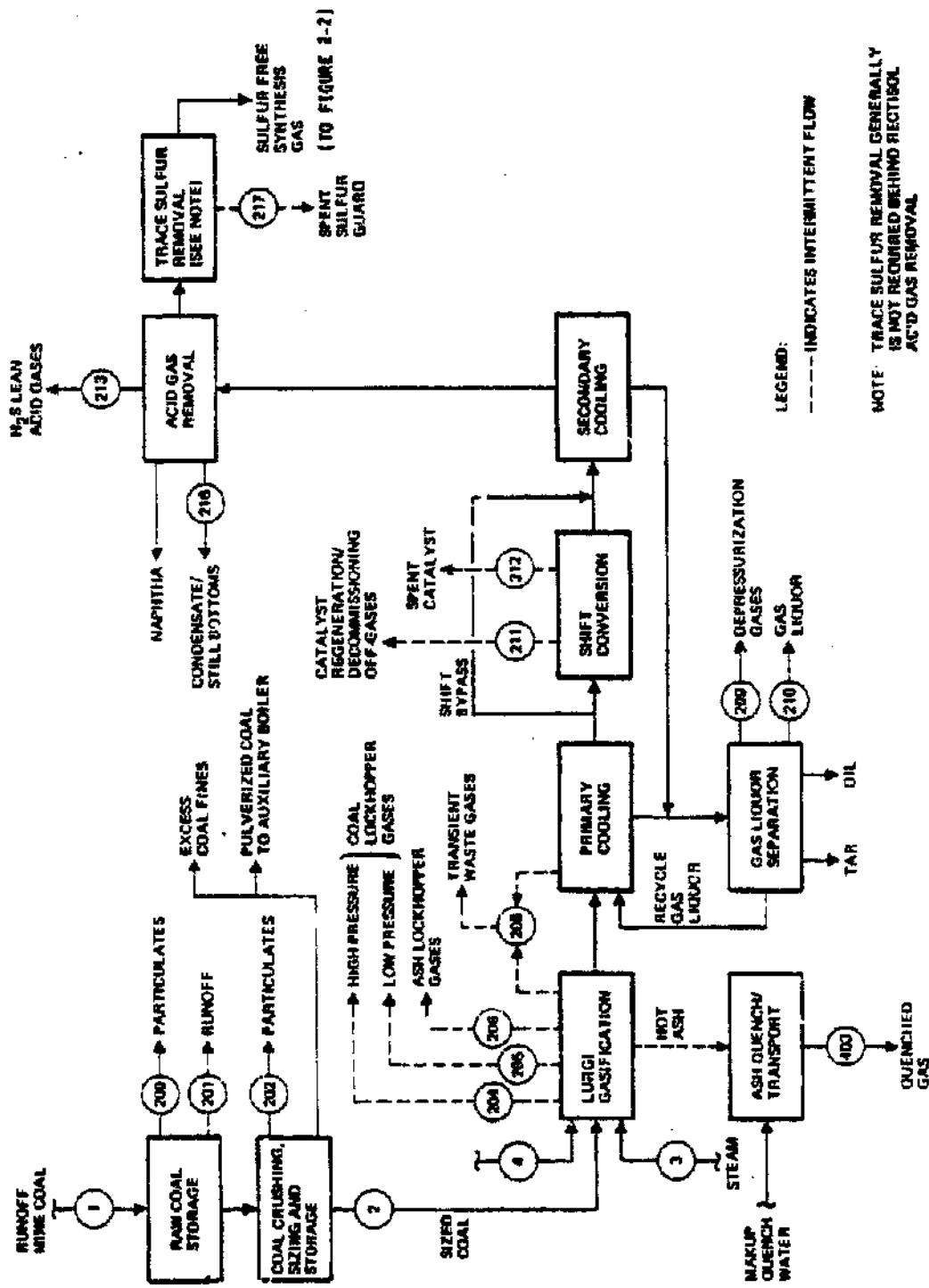size coal to a nominal 3.8 cm size for use as Lurgi gasifier feed.

Figure 2-1. Operations associated with synthesis gas production in Lurgi-based indirect liquefaction facilities
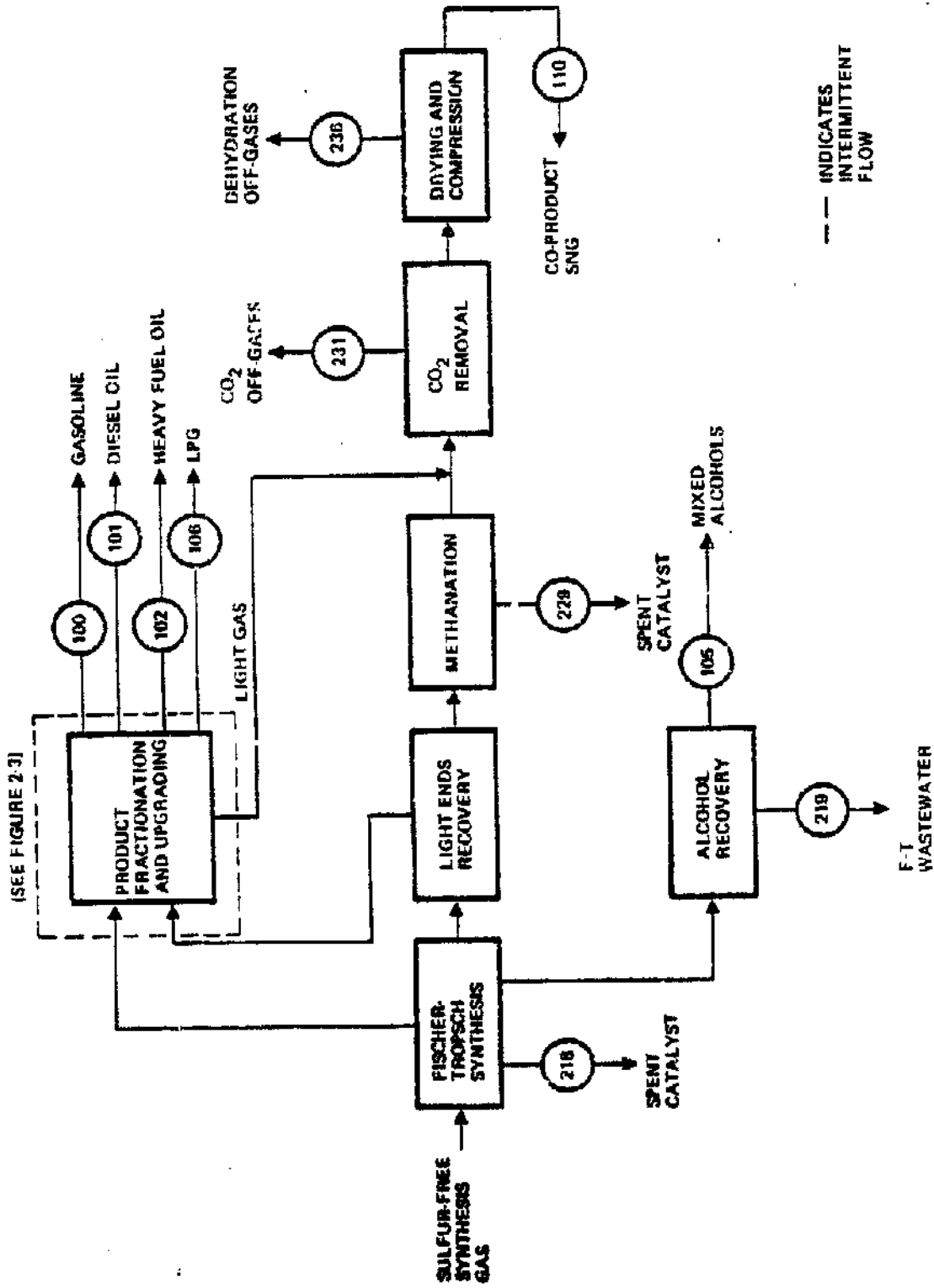
Figure 2-2. Fischer-Tropsch synthesis and product upgrading

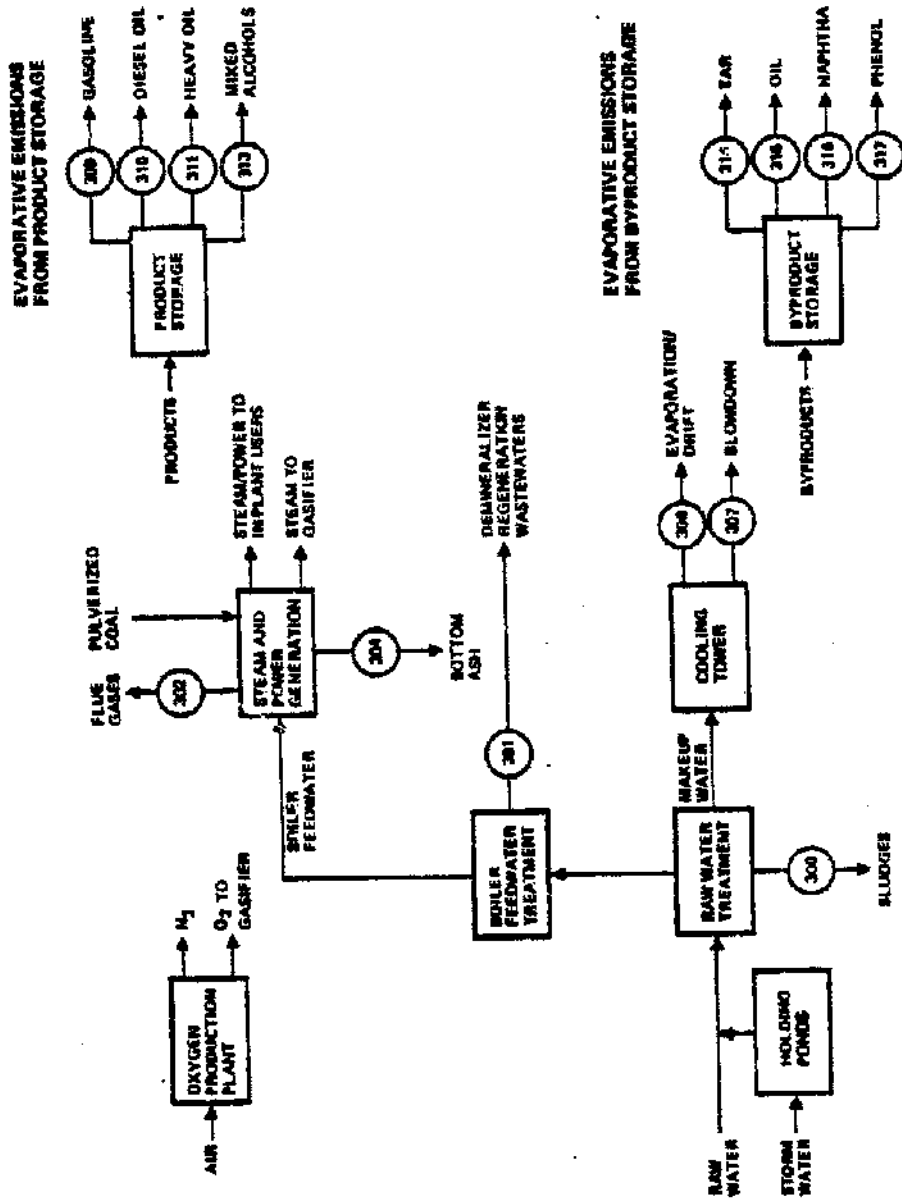Figure 2-3. Fischer-Tropsch Product Fractionation and Upgrading

Figure 2-4. Auxiliary processes associated with Lurgi-based indirect liquefaction facilities

The major waste streams associated with the coal preparation operation are coal storage pile runoff (Stream 201), fugitive dust emissions from prepared coal storage and transport (Stream 200), and dust from coal crushing and screening (Stream 202). Runoff from coal storage tends to contain high levels of suspended and dissolved solids and can be quite acidic in the case of Midwestern or Eastern coals. Dust from coal preparation consists of natural soil and overburden material as well as coal.

2.1.2 Lurgi Coal Gasification

The dry ash Lurgi gasifier is a medium pressure (2.1 to 3.2 MPa), moving bed gasifier operating below the coal ash fusion temperature. Essentially all types of coals with moisture contents below about 40 percent can be gasified, although strongly caking coals require the use of a coal distributor equipped with a stirrer. The gasifier unit consists of a coal lockhopper, a water-jacketed pressurized gasifier vessel, an ash lockhopper, and an ash quench system.

Sized coal is stored in a coal hopper directly above the gasifier and is fed to the gasifier via a coal lockhopper. Cooled or raw Lurgi gas or an inert gas such as CO_2 or N_2 can be used as the lockhopper pressurant gas. As the coal descends through the gasifier countercurrent to gas flow, it passes through "zones" of progressively higher temperatures which provide for drying, devolatilization, gasification, and combustion. A revolving grate at the bottom of the gasifier supports the ash/coal bed, provides for a uniform flow or ash to the ash lockhopper, and distributes steam and high purity oxygen uniformly across the bottom of the downward moving coal bed. The ash lockhopper allows for discharge of the ash into the ash quench system. Quenched ash is transported as a wet solid or water slurry to a clarification and solids handling system.

The hot crude gas leaving the gasifier is composed primarily of hydrogen, carbon monoxide, carbon dioxide, methane, and unreacted steam. Also present are high molecular weight organics (e.g., tars, oils, phenols), reduced sulfur and nitrogen compounds (e.g., H_2S, COS, mercaptans, NH_3, HCN), low molecular weight hydrocarbons (e.g., C_2S-C_5S, benzene, toluene), and entrained coal dust. Waste streams generated by the gasification operation

include coal lockhopper vent gases (Streams 204 and 205), ash lockhopper vent gases (Stream 206), gasifier ash (Stream 403), and transient waste gases (Stream 208).

The composition of the coal lockhopper vent gases reflects the characteristics of both the raw Lurgi gas and the lock pressurant gas. When Lurgi gases are used for lock pressurization, the lock vent gases are similar in composition to the Lurgi gases and contain organics and volatile sulfur- and nitrogen-containing compounds. Coal lockhopper vent gases may also contain entrained particulates consisting of coal particles and tarry hydrocarbon materials. When CO_2 or N_2 is used for lock pressurization, a flow of pressurizing gas into and through the lockhopper is maintained in order to minimize, or possibly eliminate, the backflow of raw gas. As a result, the lockhopper gases will consist largely of the pressurization gas, e.g., N_2 or CO_2 but will also contain raw gasifier gases and particulate. Transient gases generated during gasifier startup, shutdown, and upset conditions contain the same types of substances as coal lockhopper gases do when Lurgi gases are used as the lockhopper pressurant.

Ash from the Lurgi gasifier is similar to ash from coal combustion in that it consists almost entirely of mineral matter originally present in the coal. However, gasifier ash will have somewhat higher levels of residual carbon. Ash lockhopper vent gases consist primarily of steam with some entrained particulate matter (ash fines) and raw gasifier gases.

2.1.3 Gas Purification and Upgrading

The gas purification and upgrading operation consists of: (1) gas cooling and quenching to reduce the gas temperature for subsequent processing and to remove condensible organics, moisture, entrained particulates, and water-soluble inorganics; (2) shift conversion, if necessary, to obtain the required ratio of H_2 to CO for product synthesis; (3) acid gas treatment for removal of CO_2 and reduced sulfur compounds; and (4) removal of trace sulfur compounds using "sulfur guards."

Gas Cooling and Dust/Heavy Organics Removal

Raw Lurgi gas is cooled in stages with some heat recovery via steam generation. Initial cooling is carried out in a "wash cooler." Gas from the wash cooler is further cooled in a waste heat boiler which produces medium

pressure steam. Moisture and heavy organics such as tars, oils, and phenols are condensed as the raw gas is cooled, producing a gas liquor stream which is routed to the gas liquor separation unit. The gas liquor also contains water soluble gaseous species such as ammonia, sulfides, cyanides, and carbon dioxide. In the gas liquor separation unit, dissolved gases, tars, and oils are separated from the water in a depressurization vessel followed by phase separators. The gas washing process also removes essentially all of the dust entrained in the raw gas, which subsequently becomes admixed with the tar. The separated oils and tars are recovered as by-products which can be used as on-site fuels, sold as by-products, gasified in an auxiliary partial oxidation gasifier to produce additional synthesis gas, or upgraded into materials suitable for blending with other facility products. Dusty tar from the tar separator can be recycled (to extinction) to the top of the gasifier (2) or gasified in an auxiliary partial oxidation gasifier to produce additional synthesis gas. Gas liquor (Stream 210) and depressurization gases (Stream 209) are the major waste streams leaving the gas liquor separation unit.

Lurgi gas liquor contains appreciable quantities of dissolved/suspended organic compounds. Inorganics present are mainly ammonia and bicarbonate, with smaller amounts of sulfide, sulfite, sulfate, thiocyanate, and cyanide. This liquor also contains trace elements which were scrubbed from the raw gas or leached from the entrained coal particles that were scrubbed from the gas. In general though, Lurgi gas liquor contains low levels of inorganic suspended and dissolved solids. The quantity of gas liquor generated is determined by the moisture content of the raw gas, which in turn is a function of the coal moisture content and the gasifier feed stream-to-coal ratio. In general, as the quantity of gas liquor generated (per unit of coal gasified) increases, the pollutant concentrations in the gas liquor decrease.

Shift Conversion

Gases suitable for feed to F-T synthesis should have slightly greater than a 2:1 ratio of hydrogen-to-carbon monoxide and no more than a few percent carbon dioxide. Depending on the specific coal gasified and/or the degree of CO_2 removal obtained in the downstream acid gas removal step,

"shifting" of a portion of the Lurgi gas may be required to obtain the necessary ratio.

For application to Lurgi based synfuels facilities, it is desirable to conduct the shift reaction at moderate to high temperatures (greater than 500K) for reasons of thermal efficiency. Sulfided cobalt molydate based catalysts, which are active at temperatures above 500K, are not affected by the presence of gaseous sulfur compounds. Cobalt molybdate based catalysts are also active for the hydrolysis of carbonyl sulfide. HCN may also be partially hydrogenated to NH_3 over the catalyst.

Shift catalysts must be periodically regenerated to remove accumulated carbon deposits. This is accomplished by controlled oxidation with air to burn off carbon and reduced sulfur. An offgas is produced containing large amounts of oxidized sulfur. After a few regeneration cycles, shift catalysts lose activity due to physical degradation or accumulation of chemical poisons and must be replaced. Thus, spent shift catalyst (Stream 212) and catalyst regeneration/decommissioning offgases (Stream 211) are the major waste streams from shift conversion.

Acid Gas Removal

Removal of H_2S and other sulfur compounds from quenched Lurgi gas is necessary to prevent catalyst poisoning in subsequent synthesis operations. The removal of most of the CO_2 is necessary to obtain a gas composition meeting the stoichiometric requirements for synthesis feed gas.

Most existing Lurgi gasification plants overseas as well as proposed Lurgi plants for the U.S. feature the non-selective Rectisol process for acid gas removal (AGR). This process is based upon the physical absorption of CO_2, H_2S, COS, and high molecular weight organic compounds in cold methanol. With non-selective operation, CO_2 and sulfur species are removed together and a single acid gas stream is produced when the methanol is regenerated. Naphtha recovered by Rectisol processing can be used as an on-site fuel, sold as a by-product, or upgraded for blending with other facility products.

Waste streams generated by the Rectisol process are H_2S-lean acid gas (Stream 213) and methanol/water still bottoms (Stream 216). The acid gas

stream is expected to contain about 1.3% H_2S and 1400 ppmv COS plus mercaptans. Water condensed from the quenched Lurgi gases entering the Rectisol unit and water added to enhance recovery of the by-product naphtha leave the Rectisol unit as methanol/water still bottoms. This stream will contain small amounts of cyanides, sulfides, ammonia, chlorides, methanol, and other organics.

Trace Sulfur Removal

To protect synthesis catalysts from sulfur poisoning, zinc oxide guard beds may be used following the Rectisol process to remove residual traces of sulfur compounds. Ordinarily, the Rectisol process can attain levels down to 0.1 ppmv total sulfur species in the synthesis feed gas, but ZnO beds would provide insurance against sulfur species being present in the synthesis feed gas during periods of Rectisol process upsets. Periodically, sulfur guard material must be decommissioned and replaced. Thus, if sulfur guards are used, a solid waste consisting of spent ZnO/ZnS is generated (Stream 217).

2.1.4 Product Synthesis

Hydrocarbon production via Fischer-Tropsch synthesis can be represented by the following reactions:

$$nCO + (2n + 0.5x) H_2 = C_nH_{2n+x} + nH_2O + heat$$
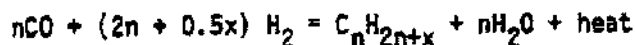
where n ranges from 1 to about 20 and is determined by process operating conditions, x = 2 for paraffins and x = 0 for olefins. Synthesis gas usually contains some CO_2 in addition to CO and H_2. Because synthesis catalysts are also active for the hydrogenation of CO_2, the presence of CO_2 does not create problems as long as the synthesis gas contains the proper ratio of $H_2/(CO + CO_2)$. F-T synthesis proceeds over iron based catalysts at 600K and 2.3 MPa (fluidized bed reactors) or 500K and 2.7 MPa (fixed bed reactors)(6).

The crude liquid fuel products will require upgrading (probably onsite) to yield final products which are marketable as substitutes for petroleum derived products. This is particularly true for motor gasolines where crude gasoline fractions would not meet octane requirements for the retail market in the U.S. F-T products could be upgraded by HF alkylation of the C_3-C_4 fraction to yield gasoline blend hydrocarbons and commercial grade LPG, by hydrotreating for destruction of olefins and oxygenated organics, by catalytic

reforming to produce more cyclic and branched chain hydrocarbons, by C_5/C_6 isomerization to increase the anti-knock quality of pentanes and hexanes, and by catalytic polymerization to convert propene/butene fractions into higher molecular weight gasoline blending compounds. All of these upgrading processes are expected to use currently available petroleum refinery technology, and have been included in the base plant. It should be noted, however, that the specific upgrading processes employed will depend largely on the desired product characteristics.

Synthetic liquid fuels synthesis generates a purge gas containing large amounts of methane and unreacted CO_x and H_2. Several options are available to handle the purge gas including use as an on-site fuel, reforming to generate additional synthesis gas, or conversion of the residual hydrogen and carbon oxides into additional methane to produce SNG. Because Lurgi derived synthesis gases initially contain large amounts of methane and because SNG has considerable market value, the methanation option was selected for analysis purposes. In actual practice, the decision regarding the disposition of synthesis purge gases involves site- and design-specific considerations which are outside the scope of this document.

Product synthesis and upgrading generates a variety of waste streams. Gaseous waste streams include CO_2 offgas from SNG purification (Stream 231), SNG dehydration offgases (Stream 236) and flue gases from process heaters (Streams 502 to 507). The principal aqueous waste stream is the F-T wastewater (Stream 219), although smaller amounts of organic-containing wastewater (Stream 508) are generated by product upgrading. Synthesis and upgrading catalysts periodically require replacement and, in some cases, require disposal. Since HF alkylation has been included in the base plant, a small volume alkylation sludge (Stream 509) will be generated.

2.1.5 Auxiliaries

The major auxiliaries required to support Lurgi based synfuels facilities are: (1) steam/power boilers; (2) makeup water treatment; (3) process cooling water; (4) liquid product/by-product storage; and (5) oxygen production.

The most significant source of waste streams from the auxiliary processes is the steam/power boiler. The boiler flue gases (Stream 302) are particularly important because the boilers will generally be coal fired and because of the potential for using the boilers to combust a wide range of gaseous, liquid, and solid wastes. Energy-rich streams which are candidates for use as boiler fuels include coal fines; by-product tars, oils, phenols, and naphtha; and hydrocarbon rich acid gases. In addition to flue gases, waste streams resulting from boiler operations include boiler blowdown condensates (Stream 303) and bottom ashes (Stream 304).

The major waste streams from makeup water treatment are sedimentation pond sludges and lime/soda softener sludges (Stream 300), and demineralizer regeneration wastewaters from the boiler feedwater treatment unit (Stream 301). Evaporation volatiles and drift (Stream 306) and cooling tower blowdown (Stream 307) are the major waste streams from the cooling water system.

Storage of synthesis products and Lurgi by-products is accompanied by evaporative emissions (Streams 309, 310, 311, 313, 314, 315, 316, and 317). These vapors consist primarily of low molecular weight organic compounds and, in the case of gasolines and Lurgi by-products, aromatic compounds such as benzene and toluene.

The oxygen plant itself is not a major source of waste streams. However, as a major consumer of energy, it impacts the magnitude of the waste streams produced in other units, particularly in the steam/power generation unit and the cooling water system.

2.1.6 Fugitive and Miscellaneous Wastes

In addition to the waste streams associated with specific processes, there are wastes which are of non-specific origins such as fugitive organic emissions (Stream 233). There are many potential sources of fugitive organic emissions in an indirect coal liquefaction plant. These include pumps, compressors, valves, flanges, and pressure relief devices.

2.2 POLLUTION CONTROL

At the present time, there are no Lurgi based indirect coal liquefaction plants in commercial operation in the United States. In addition, very limited information is available which relates to pollution control processes used by the only significant Lurgi based indirect liquefaction plant in commercial operation outside of the U.S. (i.e., the SASOL facilities). The emphasis on pollution control which has been incorporated into designs for most Lurgi based facilities abroad is generally less than that which is anticipated for U.S. plants. Therefore, directly applicable performance data for most pollution control technologies are quite limited. The potential application of most pollution control technologies to waste streams identified in Section 2.1 has, therefore, been extrapolated from their use in similar applications in industries such as petroleum refining, coke production, natural gas processing, coal cleaning, and electrical utilities. This section identifies the pollution control technologies selected for evaluation. These technologies reflect the types of alternatives which are under consideration for facilities in the U.S. It should be noted, however, that a variety of control technologies with similar performance characteristics are potentially applicable to most waste streams identified in Section 2.1.

2.2.1 Air Pollution Control

Pollution control technologies considered for gaseous waste streams presented in Section 2.1 are summarized in Table 2-3 along with the secondary waste streams generated by the control technologies. Also included in the table are the pollution control technologies considered for gaseous secondary waste streams. A majority of the gaseous waste streams are analogous to streams encountered in other industries (e.g., fugitive dust and particulate, fugitive organic emissions, and evaporative emissions) and analogous approaches to controlling these streams have been considered. Control of other gaseous waste streams generally involves Stratford sulfur recovery and/or thermal incineration, depending upon their magnitude and compositions.

2.2.2 Wastewater Treatment

Pollution control technologies considered for wastewater streams are presented in Table 2-4. Streams of major importance are the Lurgi gas liquor

TABLE 2-3. POLLUTION CONTROL TECHNOLOGIES FOR GASEOUS WASTE STREAMS

Stream Number	Stream Description	Control Technology Considered	Secondary Waste Streams Generated
200	Fugitive dust from material storage	Vegetative and chemical stabilization	None
202	Fugitive particulates from material conveying and processing	Enclosures, hoods, and fabric filters	None
205	Low-pressure coal lockhopper gases	Incineration in the boiler	Flue gas
206	Ash lockhopper vent gas	None	None
208	Transient waste gases	Incineration in the boiler	Flue gas
209	Gas liquor depressurization gases	Ammonia recovery and combustion with H₂S lean gases for treatment	See Stream 213
211	Shift catalyst regeneration/decommissioning offgas	Caustic scrubbing for SO₂ removal	Sodium sulfite scrubber sludge (Stream 445)
213	H₂S-lean gases	Stratford sulfur recovery followed by incineration in the boiler	Stratford oxidizer vent gas (Stream 414), Stratford solution bleedion (Stream 416), Flue gas
231	CO₂ offgas from SNG purification	Thermal incineration	Incinerated CO₂ offgas (Stream 429)
233	Fugitive organic emissions from process equipment	Leak detection and repair methods	None
236	SNG dehydration offgases	None	None
302	Flue gas from steam and power generation	Electrostatic precipitator for particulate control and limestone scrubbing for SO₂ control	Boiler fly ash (Stream 401), FGD sludge from limestone scrubbin. (Stream 444), treated boiler flue gas (Stream 403)
306	Cooling tower evaporation and drift	None	None
309	Evaporative emissions from gasoline storage	Floating roof tank with primary and secondary seals	None
310	Evaporative emissions from diesel oil storage	Fixed roof tank with internal floating roof with closure seals	None
311	Evaporative emissions from fuel oil storage	Fixed roof tank with internal floating roof with closure seals	None
313	Evaporative emissions from mixed alcohol storage	Floating roof tank with primary and secondary seals	None
314	Evaporative emissions from Lurgi tar storage	Fixed roof tank with internal floating roof with closure seals	None
315	Evaporative emissions from Lurgi oil storage	Fixed roof tank with internal floating roof with closure seals	None
316	Evaporative emissions from Lurgi naphtha storage	Fixed roof tank with primary and secondary seals	None
317	Evaporative emissions from Lurgi phenol storage	Fixed roof tank with internal floating roof with closure seals	None
414	Stratford oxidizer vent gas	Incineration in the boiler	Flue gas
420	Ammonia recovery overhead gases	Combined with H₂S-lean gases for treatment	See Stream 213
502-507	Flue gas from process heaters	None	None

TABLE 2-4. POLLUTION CONTROL TECHNOLOGIES FOR AQUEOUS WASTE STREAMS

Stream Number	Stream Description	Control Technology Considered	Secondary Waste Streams Generated
208	Coal storage pile runoff	Sedimentation and neutralization	Sedimentation sludge
210	Lurgi gas liquor	Control Option 1 Phenol extraction + ammonia recovery + activated sludge + chemical precipitation + activated carbon	Ammonia recovery overhead gases (Stream 428), activated sludge waste (Stream 430); chemical precipitation sludge (Stream 433)
216	Methanol/water still bottoms		
219	F-T wastewater	Control Option 2 Phenol extraction + ammonia recovery + activated sludge + forced evaporation + surface impoundment	Ammonia recovery overhead gases (Stream 428), activated sludge waste (Stream 431). leachate
508	Upgrading wastewater		
301	Demineralizer regeneration wastewater	Neutralization	None
307	Cooling tower blowdown	Sedimentation and neutralization	Sedimentation sludge
416	Stretford solution blowdown	Reductive incineration	H_2S offgas for recycle to Stretford

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Stream 210) and F-T wastewater (Stream 219) which are combined with the Rectisol condensate/still bottoms (Stream 216) and upgrading wastewater (Stream 508) for common treatment. Two treatment alternatives were considered for these streams: (1) phenol extraction, ammonia recovery, activated sludge, chemical precipitation, and activated carbon adsorption followed by discharge to surface waters; and (2) phenol extraction, ammonia recovery, forced evaporation and surface impoundment. Block flow diagrams of these treatment schemes are presented in Figure 2-4. Blowdown from the Stretford Unit (Stream 416) is treated by reductive incineration; liberated H_2S (Stream 417) is recycled to the Stretford inlet and residual salts are recycled as makeup chemicals. Other wastewater streams are essentially identical to wastes generated by coal-fired power plants or refineries, and are treated accordingly.

2.2.3 Solid Waste Management

Based upon solid waste management practices currently applied in the synfuels and other industries, and those being considered for proposed synfuels plants, many of the solid wastes will be landfilled. As indicated in Table 2-5, the only material likely to have reclamation value is the spent methanation catalyst. This nickel-based catalyst will probably be recycled to the vendor for metals recovery or reprocessing and reuse. All other solid wastes are expected to be landfilled.

2.3 SOURCE TERM ESTIMATES FOR WASTE STREAMS

This section presents source term estimates for Risk Analysis Units (RAUs) in both uncontrolled waste streams and discharge streams after waste treatment. The RAU categories considered have been previously listed in Section 1. Data sources for characterizing uncontrolled waste streams from the Lurgi based F-T synfuels facility and for estimating control technology performance are briefly described in Section 2.3.1. Source term estimates for gaseous waste streams, aqueous waste streams, and solid waste streams are presented in Section 2.3.2, 2.3.3 and 2.3.4, respectively. Where data are available, source term estimates are presented in ranges. For the majority of waste streams, only a single number is presented for each RAU representing a specific set of design/operating conditions. A single number does not imply a high accuracy for source term estimates but, rather, reflects the absence of data for estimating the influence of varying design/operating

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CONTROL OPTION 1

GAS LIQUOR — (210) → SOLVENT EXTRACTION → RECOVERED PHENOLS

SOLVENT EXTRACTION → PHOSAM-W

(476) → ACID GASES AMMONIA

PHOSAM-W → UPGRADING WASTEWATER

(608)

(216)
(219) RECTISOL STILL BOTTOMS / FISCHER TROPSCH SYNTHESIS WASTEWATERS

PHOSAM-W → AIR ACTIVATED SLUDGE

AIR ACTIVATED SLUDGE → (431) → BIOSLUDGE

AIR ACTIVATED SLUDGE → CHEMICAL PRECIPITATION

CHEMICAL PRECIPITATION → (433) → CHEMICAL PRECIPITATION SLUDGE

CHEMICAL PRECIPITATION → ACTIVATED CARBON ADSORPTION → DISCHARGE TO SURFACE WATERS

CONTROL OPTION 2

GAS LIQUOR — (210) → SOLVENT EXTRACTION → RECOVERED PHENOLS

SOLVENT EXTRACTION → PHOSAM-W

(423) → ACID GASES AMMONIA

PHOSAM-W → UPGRADING WASTEWATER

(608)

(216)
(219) RECTISOL STILL BOTTOMS / FISCHER TROPSCH SYNTHESIS WASTEWATERS

PHOSAM-W → AIR ACTIVATED SLUDGE

AIR ACTIVATED SLUDGE → (427) → BIOSLUDGE

AIR ACTIVATED SLUDGE → FORCED EVAPORATION

FORCED EVAPORATION → RECOVERED WATER

FORCED EVAPORATION → SURFACE IMPOUNDMENT

SURFACE IMPOUNDMENT → EVAPORATION
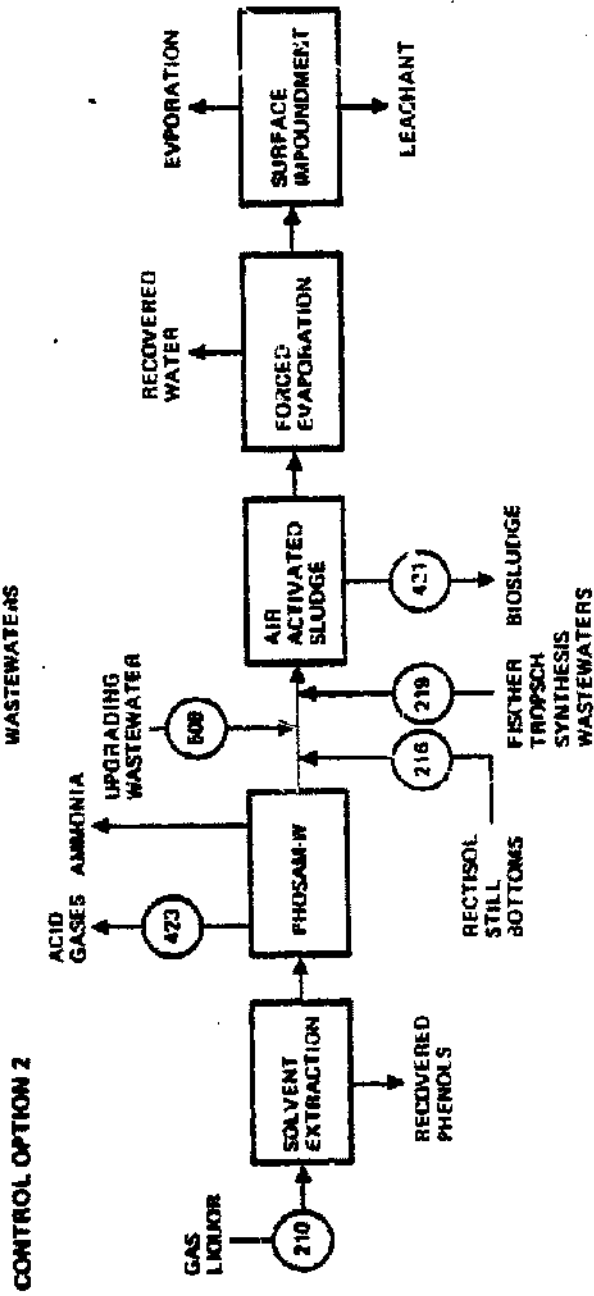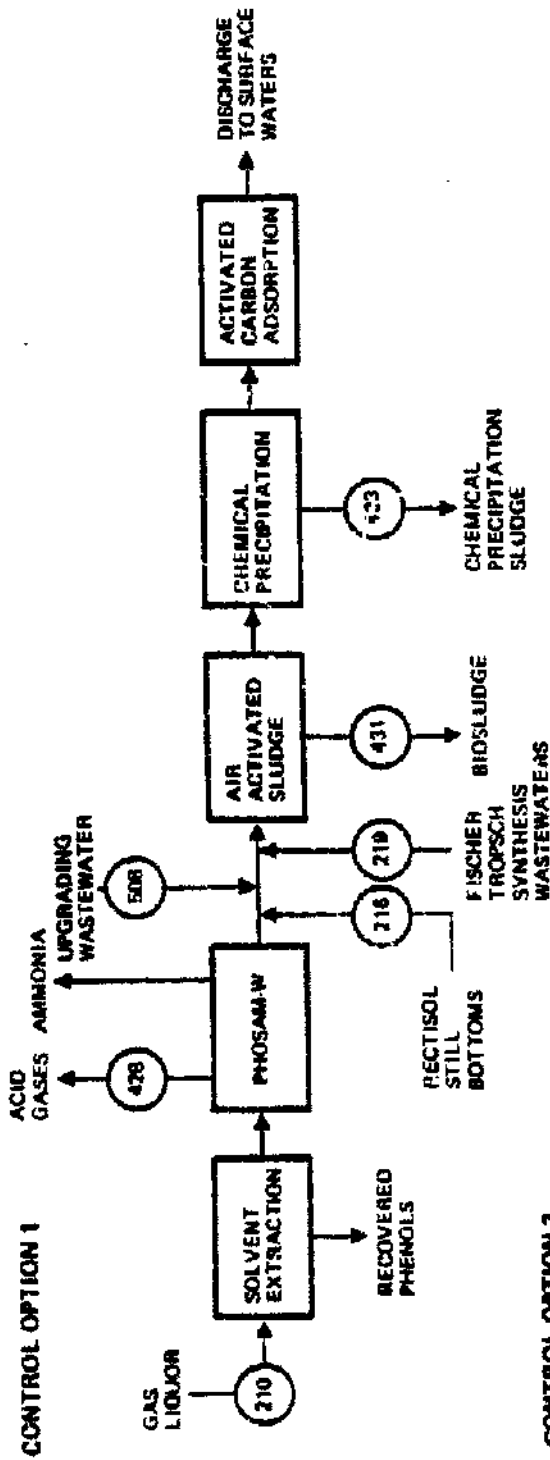
SURFACE IMPOUNDMENT → LEACHANT

Figure 2-5. Block flow diagram for wastewater treatment

2-20

TABLE 2-5. POLLUTION CONTROL TECHNOLOGIES FOR SOLID WASTE STREAMS

Stream Number	Stream Description	Control Technology Considered	Secondary Waste Streams Generated
212	Spent shift catalyst	Offsite catalyst reclamation	None
217	Spent sulfur guard	Landfill	Leachate
218	Spent F-T synthesis catalyst	Landfill	Leachate
229	Spent methanation catalyst	Offsite catalyst reclamation	None
306	Raw water treatment sludges	Landfill	Leachate
304	Boiler bottom ash	Landfill	Leachate
400	Quenched gasifier ash	Landfill	Leachate
432	Activated sludge waste	Landfill	Leachate
433	Chemical precipitation sludge	Landfill	Leachate
441	Boiler fly ash	Landfill	Leachate
444	FGD sludge from limestone scrubbing	Fixation followed by landfill	Leachate
445	Sodium sulfite scrubber sludge	Fixation followed by landfill	Leachate
446	Miscellaneous sedimentation/treatment sludges	Landfill	Leachate
509	Alkylation sludge	Neutralization followed by landfill	Leachate
510	Spent polymerization catalyst	Landfill	Leachate
511	Spent hydrogenation catalyst	Offsite catalyst reclamation	None
512	Spent hydrotreating catalyst	Offsite catalyst reclamation	None
513	Spent isomerization catalyst	Offsite catalyst reclamation	None
514	Spent reforming catalyst	Offsite catalyst reclamation	None

conditions. Uncertainties in and limitations of the source term estimates presented in this section are presented in Section 2.4.

2.3.1 Data Sources for Stream Characterization and Control Performance Estimates

The major sources of data used to develop base plant/process configurations and to define the types and characteristics of uncontrolled synthetic fuels facility waste streams were: 1) a test program of a Lurgi-type gasification facility in the Kosovo region of Yugoslavia (10); 2) a program involving the gasification of American coals in a Lurgi gasifier at Westfield, Scotland (1); 3) SASOL plant test data provided to EPA by SASOL (11); 4) a gasoline-from-coal research study conducted by the Mobil Research and Development Corporation (6); and 5) various permit filings and environmental impact statements for proposed U.S. Lurgi based SNG facilities (7,12,13).

Characteristics of treated waste streams depend largely upon the performance of the control technologies employed. Data sources used to estimate control performance include published performance data, contacts with control technologies in related conventional industries, experimental data regarding the performance of controls on Lurgi gasification waste streams, and engineering evaluations. Since few of the control technologies considered have been routinely employed in Lurgi gasification or F-T facilities, some extrapolation has generally been required in projecting control performance to a Lurgi based F-T facility.

2.3.2 Source Term Estimates for Gaseous Waste Streams

Source term estimates for uncontrolled and controlled gaseous waste streams are presented in Tables 2-6 and 2-7, respectively. Uncontrolled fugitive dust (Stream 200) and fugitive particulate (Streams 202 through 205) emissions estimates were based upon published emissions data from other industries with similar coal handling/preparation operations (14,15,16). Dust and particulate were assumed to have the same composition as the parent coal with respect to ash and trace elements, regardless of particle size. In the case of uncontrolled fugitive dust, the tabulated range of respirable particulate corresponds 5 to 100% of the uncontrolled emission. A fugitive dust control efficiency of 90% was assumed. In the case of uncontrolled fugitive

TABLE 2-6. SOURCE TERM ESTIMATES FOR UNCONTROLLED GASEOUS WASTE STREAMS

Risk Analysis Units	Waste Stream Generation Rate, kg/hr						
	200 Fugitive Dust	202 Fugitive Particulate	205 L.P. Lockhopper Vent Gas	206 Ash Lockhopper Vent Gas	208 Transient Waste Gas	209 Depressurization Gases	211 Shift Catalyst Regeneration Offgas
1. Carbon monoxide			190		13000	130	0
2. Sulfur oxides			0			0	3600
3. Nitrogen oxides			6.5	0.17		140	
4. Acid gases			3.0	0.23	400	77	
5. Alkaline gases			96		390	464	
6. Hydrocarbon gases					5800		
7. Formaldehyde							
8. Volatile organochlorines							
9. Volatile carboxylic acids							
10. Volatile O&S heterocyclics							
11. Volatile N-heterocyclics							
12. Benzene			1.8			138	
13. Aliphatic/alicyclic			3.3			390	
14. Mono/diaromatic hydrocarbons (excluding benzene)							
15. Polycyclic aromatic hydrocarbons			7.1		1400		
16. Aliphatic amines (excluding N-heterocyclics)							
17. Aromatic amines (excluding N-heterocyclics)							
18. Alkaline nitrogen heterocyclics ("azarenes") (including "volatiles")							
19. Neutral N, O, S heterocyclics (excluding "volatiles")							
20. Carboxylic acids (excluding "volatiles")							
21. Phenols							
22. Aldehydes and ketones ("carbonyls") (excluding formaldehyde)							
23. Nonheterocyclic organics			1.6			140	
24. Sulfur							
25. Alcohols							
26. Nitroaromatics							
27. Esters							
28. Amides							
29. Nitriles							
30. Tars		460	0.29	9.4	9.6		
31. Respirable particles	2.0-95						
32. Arsenic	$3.9 \times 10^{-4} - 5.4 \times 10^{-4}$	0.0045		7.1×10^{-4}			
33. Mercury	$8.1 \times 10^{-4} - 1.1 \times 10^{-3}$	9.3×10^{-5}		5.2×10^{-7}			
34. Nickel	$4.7 \times 10^{-4} - 6.5 \times 10^{-4}$	0.0054		2.4×10^{-4}			
35. Cadmium	$8.8 \times 10^{-4} - 1.2 \times 10^{-3}$	9.6×10^{-5}		4.8×10^{-5}			
36. Lead	0.0022-0.0030	0.025		5.5×10^{-4}			
37. Other trace elements				NOT AVAILABLE			
38. Radioactive materials	0	0	0		0	0	0
39. Other remaining materials	0	0	0		0	0	0

TABLE 2-6. CONTINUED

With Emphasis Units	213 H2S-Lean Gases	231 CO2 Offgas from SNG Purification	233 Fugitive Organics from Process Equipment	236 SNG Dehydration Offgas	302 Boiler Flue Gas	304 Evaporative Emissions from Gasoline Storage	310 Evaporative Emissions from Diesel Oil Storage
Carbon monoxide	4800	0.60	0	0	120	0	0
sulfur oxides	0	0	0	0	2600	0	0
Nitrogen oxides	0	0	0	0	980	0	0
Acid gases	3100	0	0	0	0	0	0
Alkaline gases	1.1	0	290	0	93	0	0
Hydrocarbon gases	15000	200	0	0	0	0	0
Formaldehyde	0	0	0	0	0	0	0
Volatile organochlorines	0	0	0	0	0	0	0
Volatile carboxylic acids	0	0	0	0	0	0	0
Volatile C&S heterocyclics	0	0	0	0	0	0	0
Volatile N-heterocyclics	0	0	0	0	0	0	0
Benzene	0	0	8.0×10^{-5}	0	0	$2.6-4.8$	$1.5 \times 10^{-6}-5.8 \times 10^{-6}$
Aliphatic/alicyclic	200	0	70	0	0	$0.53-0.99$	$0.024-0.695$
Non/diaromatic hydrocarbons (excluding benzene)	140	0	30	0	0.013	0	$8.0073-0.028$
Polycyclic aromatic	0	0	8.025	0	0.0056	0	$2.6 \times 10^{-4}-1.0 \times 10^{-3}$
Aliphatic amines (including)	0	0	0	0	0	0	0
Aromatic amines (excluding)	0	0	0	0	0	0	0
N-heterocyclics	0	0	0	0	0	0	0
Alkyl benzenes hetero-cyclics ("nonvolatile")	0	0	0	0	0	0	0
Carboxylic acids (excluding "volatiles")	0	0	0	0	0	0	0
Phenol ("volatiles")	0	0	5.6	0	0	0	0
Aldehydes and ketones ("carbonyls")(excluding formaldehyde)	0	0	0	0	0	0	0
Nonaromatic organic	1200	0	24	0	0	0	0
Alcohols	750	0	0	0	190	0	0
Nitroaromatics	0	0	0	0	0.66	0	0
Esters	0	0	0	0	0.068	0	0
Amides	0	0	0	0	0.77	0	0
Nitriles	0	0	0	0	0.014	0	0
Tars	0	0	0	0	1.6	0	0
Respirable particles	0	0	0	0		0	0
Arsenic	0	0	0	0		0	0
Mercury	0	0	0	0		0	0
Nickel	0	0	0	0		0	0
Cadmium	0	0	0	0		0	0
Lead	0	0	0	0		0	0
Other trace elements	0	0	0	0 NOT AVAILABLE	$0.21-0.42$		
Radioactive materials (uCi/hr)	0	0	0	0	0	0	0
Other remaining materials	0	0	0	0		0	0

(Continued)

TABLE 2-6. CONTINUED

			Waste Stream Generation Rate, kg/hr			
	311	313	314	315	316	317
Risk Analysis Units	Evaporative Emissions from Fuel Oil Storage	Evaporative Emissions from Mixed Alcohol Storage	Evaporative Emissions from Tar Storage	Evaporative Emissions from Luryl Oil Storage	Evaporative Emissions from Naphtha Storage	Evaporative Emissions from Phenol Storage
Carbon monoxide	0	0	0	0	0	0
Sulfur oxides	0	0	0	0	0	0
Nitrogen oxides	0	0	0	0	0	0
Acid gases	0	0	0	0	0	0
Alkaline gases	0	0	0	0	0	0
Hydrocarbon gases	0	0	0	0	0	0
Formaldehyde	0	0	0	0	0	0
Volatile organochlorines	0	0	0	0	0	0
Volatile carboxylic acids	0	0	0	0	0	0
Volatile O&S heterocyclics	0	0	0	0	0.013-0.025	0
Volatile N-heterocyclics	0	0	0	0	0	0
Benzene	$2.5 \times 10^{-8} - 9.2 \times 10^{-4}$	0	0.21-1.1	0.12-0.39	0.14-0.28	0
Aliphatic/alicyclic hydrocarbons	$3.5 \times 10^{-8} - 5.4 \times 10^{-4}$	0	0.021-0.31	0.012-0.039	0.076-0.15	0
Mono/diaromatic hydrocarbons (excluding benzene)		0	0.086-0.45	0.049-0.16	0.47-0.95	0
Polycyclic aromatic hydrocarbons	$3.5 \times 10^{-8} - 1.1 \times 10^{-5}$	0	$1.2 \times 10^{-4} - 6.5 \times 10^{-4}$	$7.1 \times 10^{-5} - 2.3 \times 10^{-4}$	0	0
Aliphatic amines (excluding N-heterocyclics)	0	0	0	0	0	0
Aromatic amines (excluding N-heterocyclics)	0	0	0	0	0	0
Alkaline nitrogen heterocyclics ["azaarenes"]	0	0	0	0	0	0
Neutral N, O, S heterocyclics (excluding "volatiles")	0	0	0	0	0.0077-0.015	0
Carboxylic acids (including "volatiles")	0	0	0	0	0	0
Phenols	0	0.13-0.36	0.0025-0.013	0.0015-0.0047	0	0.16-0.79
Aldehydes and ketones ["carbonyls"] (excluding formaldehyde)	0				0	0
Nonheterocyclic organo-sulfur	0	0.54-1.8	0.021-0.13	0.018-0.046	0	0
Alcohols	0	0	0	0	0	0
Nitroaromatics	0	0	0	0	0	0
Esters	0	0	0	0	0	0
Amides	0	0	0	0	0	0
Nitriles	0	0	0	0	0	0
Tars	0	0	0	0	0	0
Respirable particles	0	0	0	0	0	0
Arsenic	0	0	0	0	0	0
Mercury	0	0	0	0	0	0
Nickel	0	0	0	0	0	0
Cadmium	0	0	0	NOT AVAILABLE	0	0
Lead	0	0	0		0	0
Other trace elements	0	0	0		0	100
Radioactive materials	0	0	0	0	0	0
Other remaining materials	0	0	0	0	0	0

(Continued)

TABLE 2-6. CONTINUED

	Waste Stream Generation Rate, kg/hr			
Risk Analysis Units	415 Stretford Oxidizer Vent Gas	428 Ammonia Recovery Overhead Gases	306 Cooling Tower Evaporation and Drift	502-507 Flue Gas From Process Heaters
1 Carbon monoxide	0	130	0	1.8
2 Sulfur oxides	0	0	0	0
3 Nitrogen oxides	0	0	0	11
4 Acid gases	0	230	2.6×10^{-4}	0
5 Alkaline gases	3.9	19	7.3×10^{-4}	0
6 Hydrocarbon gases	0	700	0	0.72
7 Formaldehyde	0	0	0	0
8 Volatile organochlorines	0	0	0	0
9 Volatile carboxylic acids	0	0	0	0
10 Volatile O&S heterocyclics	0	0	0	0
11 Volatile N-heterocyclics	0	0	0	0
12 Benzene	0	0	0	0
13 Aliphatic/alicyclic	0	0	0	0
14 Mono/Diaromatic hydrocarbons (excluding benzene)	0	510	0	0
15 Polycyclic aromatic hydrocarbons	0	0	0	0
16 Aliphatic amines (excluding N-heterocyclics)	0	0	0	0
17 Aromatic amines (excluding N-heterocyclics)	0	0	0	0
18 Alkaline nitrogen heterocyclic ("azarenes") (excluding "volatiles")	0	0	0	0
19 Neutral N, O, S heterocyclics (excluding "voaltiles")	0	0	0	0
20 Carboxylic acids (excluding "volatiles")	0	0	0	0
21 Phenols	0	0	0	0
22 Aldehydes and ketones ("carbonyls")(excluding formaldehyde)	0	0	0	0
23 Nonheterocyclic organo sulfur	0	120	0	0
24 Alcohols	0	0	0	0
25 Nitroaromatics	0	0	0	0
26 Esters	0	0	0	0
27 Amides	0	0	0	0
28 Nitriles	0	0	0	0
29 Tars	0	0	0	0.45-1.3
30 Respirable particles	0	0	0	0
31 Arsenic	0	0	5.0×10^{-5}	0
32 Mercury	0	0	1.3×10^{-5}	0
33 Nickel	0	0	3.5×10^{-4}	0
34 Cadmium	0	0	7.5×10^{-5}	0
35 Lead	0	0	2.6×10^{-4}	0
36 Other trace elements		NOT AVAILABLE		
37 Radioactive materials	0	0	0	0
38 Other remaining materials	0	0	0	0

*Maximum duration is 1 hour at this rate plus an additional 7 hours at about half this rate. This is the worst case transient emission and could occur up to 45 times per year.
†Shift catalyst regeneration/decommissioning is estimated to occur for a total period of of 60 hours per year.
‡A small quantity of methane and glycol would be present in this stream although no basis exists for estimating the emission rates.
§Small amounts of other organic compounds may be present in this stream, although supporting data are not available.

TABLE 2-7. SOURCE TERM ESTIMATES FOR CONTROLLED GASEOUS WASTE STREAMS

	Waste Stream Generation Rate, kg/hr						
RCRA Analyte Units	203 Fugitive Dust	202 Fugitive Particulate	233 Fugitive Organic Emissions from Process Equipment	236 SNG Dehydration Offgas	305 Evaporative Emissions from Gasoline Storage	310 Evaporative Emissions from Diesel Oil Storage	206 Ash Lockhopper Vent Gas
1 Carbon monoxide	o	o	o	o	o	o	o
2 Sulfur oxides	o	o	o	o	o	o	o
3 Nitrogen oxides	o	o	o	o	o	o	0.17
4 Acid gases	o	o	o	o	o	o	0.23
5 Alkaline gases	o	o	56-72	o	o	o	●
6 Hydrocarbon gases	●	o	o	●	o	o	●
7 Formaldehyde	o	o	o	●	o	o	●
8 Volatile organochlorines	o	o	o	●	o	o	●
9 Volatile carboxylic acids	o	o	o	●	o	o	●
10 Volatile BTX heterocyclics	o	●	1.3x10⁻⁵, 6.7x10⁻⁵	●	0.14-0.27	3.9x10⁻³	●
11 Volatile N-heterocyclics	o	o	18-23	o	0.028-0.055	0.0043	●
12 Benzene	o	o	7.6-9.7	o	●	0.0039	●
13 Aliphatic/Alicyclic	o	o		o			●
14 Mono/diaromatic hydrocarbon (excluding benzene)	●	●	0.0043-0.021	o	o	6.4x10⁻³	●
15 Polycyclic aromatic hydrocarbons	●	●	o	o	o	o	●
16 Aliphatic amines (excluding heterocyclics)	o	o	o	o	o	●	●
17 Aromatic amines (excluding heterocyclics)	o	o	o	o	o	●	●
18 Aliphatic nitrogen heterocyclics ("azarenes")	o	o	o	o	o	o	o
19 Phenol N, O, S heterocyclics (excluding "volatiles")	o	o	0	o	o	o	o
20 Cyclic (excluding "volatiles")	o	o	1.4-1.8	o	o	o	o
21 Carboxylic acids (excluding "volatiles")	oo	oo		oo	oo	oo	oo
22 Phenol	o	o	o	o	o	o	o
23 Aldehydes and ketones (carbonyls) (excluding formaldehyde)	o	o	6.2-7.7	o	o	o	o
24 N-heterocyclic organo	o	●	●	o	●	●	●
25 Water	●	●	●	●	o	●	●
26 Alcohols	●	●	●	●	o	●	●
27 Nitroaromatics	●	●	●	o	o	●	●
28 Esters	o	●	●	o	o	●	●
29 Amides	o	●	●	●	●	●	●
30 Nitriles	o	●	●	●	o	●	●
31 Tars	●	●	●	●	●	●	●
32 Respirable particles	0.20-5.5	11-46	●	●	●	●	2.1x10⁻⁴
33 Arsenic	3.9x10⁻⁶-5.4x10⁻⁵	1.3x10⁻⁴-4.5x10⁻⁴	o	●	o	o	3.5x10⁻⁷
34 Mercury	8.1x10⁻⁷-1.1x10⁻⁶	2.8x10⁻⁶-9.3x10⁻⁶	o	o	o	o	2.9x10⁻⁴
35 Nickel	4.7x10⁻⁵-5.6x10⁻⁵	1.6x10⁻⁴-5.4x10⁻⁴	o	o	o	o	4.8x10⁻⁴
36 Cadmium	4.4x10⁻⁵-1.3x10⁻⁶	2.9x10⁻⁶-9.6x10⁻⁶	o	o	o	o	5.6x10⁻⁴
37 Lead	7.3x10⁻⁴-1.3x10⁻⁴	7.5x10⁻⁶-2.5x10⁻³	o	o	o	o	8.10
38 Other trace elements	4.7x10⁻⁴-4.5x10⁻⁴	0.0016-0.0054	●	●	●	●	●
39 Radioactive materials							
40 Other remaining materials	o	o	o	o	o	o	o

(Continued)

TABLE 2-7. CONTINUED

Unit Analysis Units	Waste Stream Generation Rate kg/hr				
	311 Evaporative Emissions from Fuel Oil Storage	313 Evaporative Emissions from Mixed Alcohol Storage	314 Evaporative Emissions from Tar Storage	315 Evaporative Emissions from Fuel Oil Surge Storage	316 Evaporative Emissions from Naphtha Storage
1 Carbon monoxide	0	0	0	0	0
2 Sulfur oxides	0	0	0	0	0
3 Nitrogen oxides	0	0	0	0	0
4 Acid gases	0	0	0	0	0
5 Alkaline gases	0	0	0	0	0
6 Hydrocarbon gases	0	0	0	0	0
7 Formaldehyde	0	0	0	0	0
8 Volatile organochlorides	0	0	0	0	0
9 Volatile carboxylic acids	0	0	0	0	0
10 Volatile S&O heterocyclics	0	0	0	0	0
11 Volatile N-heterocyclics	0	0	0	0	0
12 Ketones	2.5×10^{-5}-1.6×10^{-4} 1.6×10^{-5}-6.9×10^{-5}	0	0.0069-0.0053 6.9×10^{-4}-8.2×10^{-4} 0.0028-0.0034	0.0024-0.0043 3.4×10^{-4}-4.2×10^{-4} 0.0014-0.0017	7.8×10^{-4}-3.4×10^{-3}
13 Aliphatic/alicyclic	0	0	0.0026-0.0031 0.0056-0.0058 0.0020-0.0021	0.0012-0.0016 0.0027-0.0035 9.7×10^{-4}-3.2×10^{-3}	0.0086-0.016 0.0047-0.0085 0.029-0.053
14 Mono/diaromatic hydrocarbons (including benzene)	3.6×10^{-2}-3.4×10^{-6}	0	4.1×10^{-6}-4.9×10^{-5}	2.0×10^{-6}-2.5×10^{-6}	0
15 Polycyclic aromatic hydrocarbons	0	0	0	0	0
16 Aliphatic amines (excluding)	0	0	0	0	0
17 Aromatic amines (excluding)	0	0	0	0	0
18 N-heterocyclics	0	0	0	0	0
19 Alkaline nitrogen hetero-cyclics ("azaarenes") (excluding "volatiles")	0	0	0	0	0
19 Alcohol E, <3 carbon-cyclics (excluding "volatiles")	0	0	0	0	0
20 Carboxylic acids (excluding "volatiles")	0	0	8.6×10^{-5}-1.0×10^{-6}	4.1×10^{-5}-5.1×10^{-5}	1.8×10^{-4}-3.7×10^{-4}
21 Phenols	0	0.047-0.15	0	0	0
22 Carbohydrates and ketones ("carbonyls")(excluding formaldehyde)	0	0.20-8.61	8.2×10^{-4}-9.8×10^{-4}	4.0×10^{-4}-5.8×10^{-4}	0
23 Nonheterocyclic organo...	0	0	0	0	0
24 Sulfur	0	0	0	0	0
25 Alcohols	0	0	0	0	0
26 Nitroaromatics	0	0	0	0	0
27 Esters	0	0	0	0	0
28 Amides	0	0	0	0	0
29 Nitriles	0	0	0	0	0
30 Tars	0	0	0	0	0
31 Respirable particles	0	0	0	0	0
32 Arsenic	0	0	0	0	0
33 Mercury	0	0	0	0	0
34 Nickel	0	0	0	0	0
35 Calcium	0	0	0	0	0
36 Lead	0	0	0	0	0
37 Other trace elements	0	0	0	0	0
38 Radioactive materials	0	0	0	0	0
39 Other combusting materials	0	0	0	0	0

(Continued)

TABLE 2-7. CONTINUED

Waste Stream Generation Rate, kg/hr

Risk Analysis Units	311 Evaporative Emissions (from Phenol) Storage	211 Shift Catalyst Regeneration Offgas	302 Boiler, Fuel Gas	208 Transient Waste Gases	429 Incinerated CO₂ Gas	306 Cooling Tower Evaporation and Drift	502-507 Flue Gas From Process Heaters
1 Carbon monoxide			130	3.6	1.3		3.8
2 Sulfur oxides		360	1097	140			0.11
3 Nitrogen oxides			1200-1800	140			
4 Acid gases						2.6x10⁻³	
5 Alkaline gases						7.3x10⁻⁴	
6 Hydrocarbon gases			<0.46	0.27	0.29		0.72
7 Formaldehyde			94				
...							
20 Carboxylic acids (including "volatiles")	0.0074-0.010		47-150	1.1-1.3			
21 Phenols	0		0.061-0.27				
22 Aldehydes and ketones ("carbonyls") (including formaldehyde)			0.0057				
23 Nonheterocyclic oxygen			0.11-0.38				
			0.0016-0.0086				0.01-1.3
			0.83-7.7				
			0.96-1.6				
			0.21			5.0x10⁻⁵	
30 Respirable particles			0			1.3x10⁻⁵	
31 Arsenic						3.5x10⁻⁴	
32 Mercury						7.5x10⁻⁵	
33 Nickel						2.6x10⁻⁴	
34 Cadmium						0.0036	
35 Lead							
36 Other trace elements							
37 Radioactive materials (mCi/hr)							
38 Other remaining materials							

[a] Small quantity of methane and glycol would be present in this stream although no basis exists for estimating the emission rates.

[b] Shift catalyst regeneration by decommissioning is estimated to occur for a total period of 60 hours per year.

[c] Includes waste gases incinerated in the boiler except the transient waste gases (Stream 208). Transients are listed separately due to their intermittent generation.

[d] Maximum short-term 1 hour at this rate plus an additional 7 hours at about half this rate. This is the worst case transient emission and could occur up to 45 times per year.

[e] Small amounts of other organic compounds may be present in this stream, although supporting data are not available.

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particulate, all particulate was assumed to be respirable. A fugitive particulate control efficiency of 90 to 97% was assumed.

Compositions of uncontrolled lockhopper vent gases are based upon test data from commercial scale Lurgi gasification (10). Low pressure coal lockhopper ver; gas (Stream 205) characteristics reflect pressurization with Lurgi gas rather than an inert gas. Transient waste gases (Stream 208) were assumed to be similar in composition to gases from air-blown Lurgi gasifiers, with frequency, duration, and volumetric flow rates based upon information in permit applications for a U. S. Lurgi based SNG facility (13). Controlled emissions from combustion of low pressure lockhopper vent gas and transient waste gases*are based upon emission factors for natural gas-fired utility boilers (17) and NSPS emission limitations.

Characteristics of the uncontrolled gas liquor depressurization gases (Stream 209) and H_2S-lean gases (Stream 213) are based upon test data from pilot and commercial scale Lurgi gasification (1,10). Control of total sulfur species in these streams in combination with ammonia recovery overhead -gases (Stream 428) is based upon 100 ppmv residual H_2S and no removal of COS, CS_2, or RSH. Controlled emissions from these waste gases*are based upon emission factors for natural gas-fired utility boilers (17) and NSPS emission limitations.

Characteristics of uncontrolled shift catalyst regeneration/decommissioning offgases (Stream 211) are based upon information in permit applications for a U.S. Lurgi based SNG facility (13). Controlled emission rate estimates are based upon an assumed SO_2 scrubbing efficiency of 90%.

Two routine offgases are associated with the product synthesis section: 1) CO_2 from SNG purification (Stream 231); and 2) SNG dehydration offgas (Stream 236). The estimated composition of the CO_2 from SNG purification was based upon published engineering estimates for SNG production applications (6,8). This stream was assumed to be controlled by thermal incineration producing an incinerated CO_2 offgas (Stream 429) containing 50 ppmv CO and 30 ppmv total hydrocarbons. Although no characterization data are available for the dehydration offgas, this stream may contain small quantities of

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* The combustion of these gas streams is similar to the combustion of fuel gas.

methane and glycol sorbent. It has been assumed that the dehydration offgas is discharged to the atmosphere without control.

Fugitive organic emissions from process equipment (Stream 233) have been estimated based upon published emission factors for pumps, compressors, valves, flanges and drains (18) and on an equipment count for a conceptual indirect coal liquefaction facility (19). Fugitive organic emissions from process equipment in gas or vapor service were all assumed to be hydrocarbon gases (RAU category 6). Emissions from process equipment in light liquid service were assumed to be gasoline and mixed alcohols in proportion to the product slate and published composition data for these products (6,20), and is the major contributor to tabulated emissions for RAU categories 13, 14, 22 and 24 in this stream. Emissions form process equipment in heavy liquid service were assumed to have a composition similar to petroleum diesel oil (21) and contribute to tabulated emissions from RAU categories 12, 13, 14, and 15 in this stream. An overall reduction in fugitive organic emissions from process equipment of 72 to 85% was assumed, although higher efficiencies were assumed for light hydrocarbons and lower efficiencies were assumed for heavy hydrocarbons (22).

Emissions associated with the flue gas from steam and power generation (Stream 302) were estimated from material balance calculations and published emission factors for utility boilers (17,23). Fly ash was assumed to have the same composition of the whole coal ash except that all mercury in the feed coal is assumed to be volatilized. Approximately 4% of the uncontrolled particulate was assumed to be respirable (23). Ranges in emission estimates for treated flue gas reflect ranges in NSPS control requirements for electric utilities and industrial steam generation units. Enrichment of arsenic, nickel, cadmium, and lead in the controlled particulate has been assumed, and approximately 73% of the controlled particulate was assumed to be respirable (23). Tabulated controlled flue gas emissions include emissions from boiler combustion of waste gases. Controlled transient waste gases have not been included due to their intermittent generation.

Evaporative emissions from product and by-product storage were based upon published emission factors from other industries (17). The composition of evaporative emissions from alcohol storage (Stream 313), gasoline storage

(Stream 329), naphtha storage (Stream 316), and phenol storage (Stream 217) were estimated from published composition data (6,20,24,25). The composition of evaporative emissions from diesel oil storage (Stream 310) was estimated from composition data from petroleum diesel (21). The composition of evaporative emissions from fuel oil storage (Stream 311) was estimated assuming that 59% of the emissions were saturates (RAU category 13), 40% were aromatics (RAU category 14) and 1% were polycyclics (RAU category 15) which is consistent with trends in shale-derived residual fuels and petroleum diesel (21). In all cases, evaporative emissions from product and by-product storage were assumed to have the same composition as the bulk liquids. This is a conservative assumption from the risk assessment standpoint because the heavier fractions of the hydrocarbon products, those usually associated with higher risks, have lesser tendency to be evaporated due to their low vapor pressures. Evaporative emissions from Lurgi tar and oil storage (Streams 314 and 315) are based upon tar tank vent gas characterization data from a commercial Lurgi facility (10).

Control efficiencies for evaporative emissions from product and by-product storage were assumed to range from 60 to 99% based upon published emission data from other industries. Tabulated ranges in uncontrolled and controlled evaporative emission rates reflect average annual values and maximum values estimated for a facility located in North Dakota.

Uncontrolled Stretford oxidizer vent gas emissions (Stream 415) are based upon vendor-supplied information (26). Controlled emission estimates are based upon an assumed NH_3 thermal destruction efficiency of 98%.

Under normal operating conditions, negligible quantities of RAU components would be expected in the cooling tower evaporation and drift (Stream 306). However, cooling tower concentration of plant wastewaters (not incorporated in the example wastewater treatment options) could result in residual wastewater contaminants being volatilized and/or entrained as drift.

Process heater sizes were established based upon published designs for F-T facilities (6). Heaters are fired with sulfur-free fuel gas. Flue gas characteristics are based upon AP-42 emission factors for gas-fired commercial heaters (17).

Estimated stack heights, exit velocities and exit temperatures for gaseous waste streams discharged through stacks are presented in Table 2-8. All other streams (e.g., fugitive dust and particulate, fugitive organic emissions and evaporative emissions) are discharged near ground level at low velocities and ambient temperature.

TABLE 2-8. STACK HEIGHT AND EXIT PROPERTIES OF GASEOUS DISCHARGE STREAMS

Stream Number	Stream Description	Stack Height, m*	Exit Velocity, m/sec†	Exit Temperature, K
211	Shift catalyst regeneration offgas	46	20	405
302	Boiler flue gas	76	20	405
429	Incinerated CO_2 offgas	46	20	405
502-507	Flue gas from process heaters	46	20	478

*Stack height information obtained from Reference 27.
†No data on exit velocity are available. Exit velocity was assumed to be 20 m/sec, a typical design velocity for gaseous discharges through stacks.

2.3.3 Source Term Estimates for Aqueous Waste Streams

Source term estimates for uncontrolled and controlled aqueous waste streams are presented in Tables 2-9 and 2-10, respectively. Coal storage pile runoff (Stream 201) flow rates were based upon rainfall data for North Dakota. Uncontrolled emission rates for trace elements present in the runoff were based upon limited published data (28,32,33). Trace elements in the run-off were conservatively assumed not to be removed during neutralization

Uncontrolled emission rate estimates for Lurgi gas liquor (Stream 210) and methanol/water still bottoms (Stream 216) were based upon published test data (4,11,29). Uncontrolled emission rate estimates for F-T wastewater (Stream 219) were based upon a published design study (6). Uncontrolled emission rates for upgrading wastewater (Stream 508) were based upon published refinery test data and design studies (6,35). These wastewater streams would

TABLE 2-9. SOURCE TERM ESTIMATES FOR UNCONTROLLED AQUEOUS WASTE STREAMS

Risk Analysis Units	201 Coal Storage Pile Runoff	216 Lurgi Gas Liquor	216 Methanol/Water Still Bottoms	219 F-T Wastewater	301 Demineralizer Regeneration Wastewater	307 Cooling Tower Blowdown	416 Stretford Solution Blowdown	507 Upgrading Wastewater
				Waste Stream Generation Rate, kg/hr				
1 Carbon monoxide								
2 Sulfur oxides								
3 Nitrogen oxides								
4 Acid gases	6.4×10^{-5}	120	0.42-0.56			0.013		
5 Alkaline gases	0.010	2000	1.7-2.1	2300-2700	4.4×10^{-4}	0.035		0.0018
6 Hydrogen gas					0.90			
7 Particulates								
8 Volatile organochlorines			0.015-0.024					0.0036
9 Volatile carboxylic acids		16	0.10-0.22					0.0014
10 Volatile N,S heterocyclics		92	0.090-0.12					
11 Volatile S-heterocyclics			0.56-0.74					
12 Phenols		160						
13 Aliphatic/alicyclic								
14 Monoaromatic hydrocarbons (excluding benzene)								
15 Polycyclic aromatic								
16 Aliphatic amines (including heterocyclics)		38	0.0092-0.012					
17 N-heterocyclics (nonvolatile)								
18 Aromatic amines (nonvolatile)								
19 Alkaline nitrogen heterocyclics ("volatiles")		250						
20 Neutral N, O, S heterocyclics (excluding "volatiles")		3300	1.3-1.7					7.4×10^{-4}
21 Phenols		0						
22 Aldehydes and ketones (nonvolatiles) (including "volatiles")								
23 Nonheterocyclic organo-N								
24 Sulfur		3.0						
25 Alcohols		<0.038			4.2×10^{-4}	0.0024		
26 Nitroaromatics	7.8×10^{-5}-0.022	0.25			0.0024	6.5×10^{-4}		
27 Esters	3.7×10^{-4}-8.4×10^{-5}	0.33			0.13	0.017		
28 Nitriles	2.5×10^{-4}-0.045	0.38			1.1×10^{-4}	0.0037		
29 Tars	1.3×10^{-4}-3.7×10^{-5}	0.25			0.22	0.013		
30 Respirable particulates	1.2×10^{-4}-6.1×10^{-4}	7.9			0.28	0.17		
31 Arsenic	0.095	0						
32 Mercury								
33 Nickel								
34 Cadmium								
35 Lead								
36 Other trace element								
37 Radioactive materials								
38 Other remaining materials								

[a] Various sulfates and sodium salts of thiosulfate, sulfate, carbonate and bicarbonate.

[b] Small amounts of other organic compounds may be present in this stream, although supporting data are not available.

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		Waste Stream Generation Rate, kg/hr				
	Risk Analysis Units	201 Coal Storage Pile Runoff	500 Treated Wastewater (Option 1)	501 Treated Wastewater (Option 2)	301 Demineralizer Regeneration Wastewater	507 Cooling Tower Blowdown
1	Carbon monoxide	0	0	0	0	0
2	Sulfur oxides	0	0	0	0	0
3	Nitrogen oxides	0	0	0	0	0
4	Acid gases	6.4×10^{-5}	4.3	9.7	4.1×10^{-4}	0.013
5	Alkaline gases	0.010	58	58	0.30	0.035
6	Hydrocarbon gases	0	0	0	0	30
7	Formaldehyde	0	0	0	0	0
8	Volatile organochlorines	0	0	0	0	0
9	Volatile carboxylic acids	0	35	120	0	0
10	Volatile O&S heterocyclics	0	4.4×10^{-5}	0.0056	0	0
11	Volatile N-heterocyclics	0	0	0	0	0
12	Benzene	0	0.0042	0.56	0	0
13	Aliphatic/alicyclic	0	2.8×10^{-4}	0.037	0	0
14	Mono/Diaromatic hydrocarbons (excluding benzene)	0	0.023	3.1	0	0
15	Polycyclic aromatic hydrocarbons	0	0.034	4.5	0	0
16	Aliphatic amines (excluding N-heterocyclics)	0	0	0	0	0
17	Aromatic amines (excluding N-heterocyclics)	0	0	0	0	0
18	Alkaline nitrogen heterocyclics ("azarenes") (excluding "volatiles")	0	0	0	0	0
19	Neutral N, O, S heterocyclics (excluding "volatiles")	0	0.0089	1.2	0	0
20	Carboxylic acids (excluding "volatiles")	0	3.5	12	0	0
21	Phenols	0	0.19	9.0	0	0
22	Aldehydes and ketones ("carbonyls")(excluding formaldehyde)	0	6.7×10^{-5}	3.4×10^{-4}	0	0
23	Nonheterocyclic organo sulfur	0	0	0	0	0
24	Alcohols	0	0.017	0.085	0	0
25	Nitroaromatics	0	0	0	0	0
26	Esters	0	7.6×10^{-6}	3.9×10^{-5}	0	0
27	Amides	0	0	0	0	0
28	Nitriles	0	0	0	0	0
29	Tars	0	0	0	0	0
30	Respirable particles	0	0	0	0	0
31	Arsenic	$7.4 \times 10^{-5} - 0.022$	3.8	3.8	4.2×10^{-4}	0.0024
32	Mercury	$3.7 \times 10^{-5} - 4.6 \times 10^{-5}$	<0.035	<0.035	0.0024	6.5×10^{-4}
33	Nickel	$2.8 \times 10^{-5} - 0.061$	0.25	0.25	0.13	0.017
34	Cadmium	$1.3 \times 10^{-6} - 3.7 \times 10^{-6}$	0.038	0.038	1.1×10^{-4}	0.0037
35	Lead	$1.2 \times 10^{-4} - 6.1 \times 10^{-4}$	0.25	0.25	0.22	0.013
36	Other trace elements	0.098	7.9	7.9	0.20	0.17
37	Radioactive materials	0	0	0	0	0
38	Other remaining materials	0	0	0	0	0

be combined for treatment and two treatment alternatives were evaluated:
1) phenol extraction, ammonia recovery and activated sludge followed by
chemical precipitation, activated carbon adsorption and discharge to surface
waters; and 2) phenol extraction, ammonia recovery and activated sludge
followed by forced evaporation and surface impoundment. The assumed perfor-
mance for the Option 1 control alternative included 95 to 98% removal of
H_2S , HCN and NH_3, and 98 to 99.99% removal of organic compounds. The assumed
performance for the Option 2 control alternative included about 98% removal
of H_2S and NH_3, 86% removal of HCN, 95 to 97% removal of organic acids, tars
and alcohols, and 99.7% removal of phenols.

The quality of uncontrolled demineralizer regeneration wastewater
(Stream 302) and cooling tower blowdown (Stream 307) (in the absence of cool-
ing tower concentration of wastewater) is largely dependent upon the quality
of available feed water. Although these streams are likely to contain low
levels of trace elements, emissions of trace elements in these streams are
expected to be small relative to emissions from other sources within the
facility. Emission estimates for these streams are based upon average con-
centrations in the electric utility industry (33).

Stretford solution blowdown (Stream 416) would contain vanadates and
sodium salts of thiosulfate, sulfate, carbonate, and thiocyanate. This waste
would be largely recovered by reductive incineration with recycle of salts
to the absorber solution and recycle of gaseous reduced sulfur species to the
absorber feed gas.

It should be noted that leachates from solid waste disposal may also be
generated. However, no landfill leachate data relating to the landfilled
waste streams are publicly available. The limited leaching data for quenched
gasifier ash are summarized in Table 2-11.

2.3.4 Source Term Estimates for Solid Waste Streams

A summary of uncontrolled solid waste streams and available characteri0
zation data are presented in Table 2-11. Spent shift conversion, methanation,
hydrogenation, hydrotreating, isomerization and reforming catalysts (Streams
212,229,511,513 and 514) would be recycled to the vendor for metal recovery
or reprocessing and reuse. All other solid wastes would be either landfilled

TABLE 2-11. SUMMARY OF UNCONTROLLED SOLID WASTE STREAMS

Stream Number	Stream Description	Average Generation Rate, kg/hr	Composition Data/Leaching Characteristics
212	Spent shift catalyst	13	Cobalt-molybdate catalyst
217	Spent sulfur guard	81	Contains zinc oxide and zinc sulfide (30)
218	Spent F-T synthesis catalyst	1160	Iron-based catalyst - No published information regarding promoting elements
229	Spent methanation catalyst	6.5	Nickel-based catalyst
300	Raw water treatment sludges	570	Contains 36% $CaCO_3$, 2% $Mg(OH)_2$, and 60% H_2O (31)
304	Boiler bottom ash	2400	Similar in composition to coal ash
403	Quenched gasifier ash	100,000 (about 20% moisture)	Trace element leachability (mg/kg dry ash): As = 0.60, Ba = 7.4, Cd = 0.020, Cr = 6.2, Hg = 0.0020, Ni = 0.40, Pb = 0.20, Se = 0.1a (4)
430	Activated sludge waste	5500-7700	May contain refractory organics and trace metals
433	Chemical precipitation sludge	2800	May contain refractory organics and trace metals
441	Boiler fly ash	4400	Similar in composition to coal ash
444	FGD sludge (from limestone scrubbing)	15,000-38,000	Contains 40% solids consisting of 48% $CaSO_3$, 16% $CaSO_4$, and 36% $CaCO_3$ (13)
445	Sodium sulfite scrubber sludge	44 (dry basis)	Consists primarily of Na_2SO_3 with small amounts of Na_2SO_4 and possibly trace metals.
509	Alkylation sludge	14	Sludge is expected to contain about 50% CaF_2, & may also contain alkylation tars.
510	Spent polymerization catalyst	0.90	Phosphoric acid on kieselguhr or quartz chips
511	Spent hydrogenation catalyst	0.10	Cobalt-molybdate catalyst
512	Spent hydrotreating catalyst	0.08	Cobalt-molybdate catalyst
513	Spent isomerization catalyst	0.40	Platinum-based catalyst
514	Spent reforming catalyst	0.60	Platinum-rhenium catalyst

directly or landfilled following chemical fixation or neutralization. Very
limited composition data and leaching data are available, and no landfill
leachate data for the landfilled waste streams are publicly available. Hence,
source term estimates cannot be prepared for either the uncontrolled or con-
trolled solid waste streams.

2.4 DATA UNCERTAINTY AND LIMITATIONS

In the previous section source term estimates for most of the waste
streams generated by a Lurgi based F-T facility, particularly waste streams
unique to synfuels technologies, were presented. However, available data
on the risk analysis units generally consist of single data sets which may
not include data for all RAUs present in the waste stream. Moreover, source
terms for waste streams from future commercial facilities could differ from
those presented in this report for several reasons. One reason for such
differences would be the uncertainty involved in estime   emission/
effluent compositions at this time. As discussed in Section 2.3, the environ-
mental data are limited, the foreign facilities tested are not entirely re-
presentative of proposed U.S. facilities, and there is necessarily some un-
certainty in making engineering estimates of trace components in discharges
from complex systems.

The major uncertainties and data limitations associated with source
term estimates for controlled gaseous and aqueous waste streams are summa-
rized in Tables 2-12 and 2-13. In the case of solid wastes, the composition
of uncontrolled waste streams is of less significance than the composition
of any leachate resulting from landfilling these wastes. Hence, the major
uncertainty associated with solid waste streams relate to leachate character-
istics (Table 2-13).

Of the parameters influencing waste stream characteristics, variations
in the feed coal composition are the most easily evaluated. Variations in
the characteristics of North Dakota lignites are summarized in Table 2-14.
These data provide a basis for evaluating ranges in certain waste stream
characteristics. For example, the design sulfur level is about twice the
average sulfur concentration for North Dakota lignites. Hence, on the aver-

TABLE 2-12. GASEOUS WASTE STREAM DATA UNCERTAINTIES AND LIMITATIONS

Stream Number	Stream Description	Major Data Uncertainties and Limitations
200	Fugitive dust from material storage	• Emission factors are based upon test data from facilities with processing similar to that employed in synfuel applications. However, emission factors may vary greatly with local conditions.
202	Fugitive particulate from material conveying and processing	
		• Trace element emissions depend upon coal composition, trace element distribution among size fractions, and control efficiency for each size fraction.
		• Data on the fraction of particulate which is respirable are limited.
206	Ash lockhopper vent gas	• Emission estimates are based upon limited test data from a foreign facility. Indicated volatiles may be directly associated with the vent gas or may be the result of impurities in the wash water stream used to scrub the gases.
		• Trace element emissions estimates are based upon the Lurgi ash composition which may differ in composition from the entrained particulates.
233	Fugitive organic emissions from process equipment	• Emission estimates are based upon petroleum refinery experience and equipment counts from conceptual F-T designs. Total mass emission rates may differ greatly in operating F-T facilities.
		• Emission composition estimates are based upon product slate estimates and limited data from Lurgi, F-T and petroleum products. Composition may differ greatly in operating F-T facilities.

(Continued)

TABLE 2-12. CONTINUED

Stream Number	Stream Description	Major Data Uncertainties and Limitations
309	Evaporative emissions from gasoline storage	• Total emission estimates based upon correlations for petroleum liquids. Total emissions from F-T liquids may differ.
310	Evaporative emissions from diesel oil storage	• Composition estimates are based upon limited data from F-T and petroleum products. Approach should be conservative in that emissions of heavy hydrocarbons are probably overestimated. Composition of emissions from F-T liquids may differ.
311	Evaporative emissions from fuel oil storage	
313	Evaporative emissions from mixed alcohol storage	
314	Evaporative emissions from Lurgi tar storage	
315	Evaporative emissions from Lurgi oil storage	
316	Evaporative emissions from Lurgi naphtha storage	
317	Evaporative emissions from phenol storage	
211	Shift catalyst regeneration/ decommissioning offgas	• Sulfur emission rates are largely dependent upon the sulfide content of the catalyst which is proprietary information. CO emissions (if any) depend upon the extent of carbon buildup on the catalyst and the efficiency of combustion during regeneration/decommissioning operations; data relating to CO emissions are not available. • The frequency of regeneration/decommissioning operations is dependent upon process conditions and catalyst properties.

(Continued)

TABLE 2-12. CONTINUED

Stream Number	Stream Description	Major Data Uncertainties and Limitations
302	Boiler flue gas	• High degree of accuracy assumed for the fraction of flue gas resulting from coal combustion since estimates are based upon a large, directly applicable data base and potentially applicable emission standards.
		• Residual tars and high molecular weight organics from waste gas combustion are unknown but are likely to be low due to long residence time and high combustion temperatures.
306	Cooling tower evaporation & drift	• Emissions are based on average cooling tower blow-down quality in the electric utility industry. Actual emissions are dependent upon local water quality, cycles of concentration and additives used.
205	Low pressure coal lockhopper gases	• Efficiency of destruction of high molecular weight organics by incineration in boiler is likely to be high, although performance data are not available.
208	Transient waste gases	
415	Stretford oxidizer vent gas	
429	Incinerated CO_2 offgas	• Emissions are based upon average data from similar applications. With proper incinerator operation, emissions are not expected to exceed estimates by more than a factor of two.
502-507	Flue gas from process heaters	• Emissions are based upon published emission factors for gas-fired commercial heaters. Estimates are assumed to be accurate since process heaters are fired with sulfur-free light process gases. However, actual emissions will vary depending on heater operation.

(Continued)

TABLE 2-13. AQUEOUS WASTE STREAM DATA UNCERTAINTY AND LIMITATIONS

Stream Number	Stream Description	Major Data Uncertainties and Limitations
201	Coal storage pile runoff	• Quantity and quality of coal storage runoff are site- and coal-specific.
500 501	Treated wastewater (Option 1) Treated wastewater (Option 2)	• Complete characterization of the gas liquor and F-T wastewater in terms of organics speciation and trace elements is not available. • The validity of extrapolating control efficiencies from petroleum refining experience is unknown.
	Leachate from solid waste disposal	• No landfill leachate data relating to the land-filled waste streams are publicly available. • Leachate generation rates are specific to the location and the design of the landfill

TABLE 2-14. VARIATIONS IN CHARACTERISTICS OF NORTH DAKOTA LIGNITES

| Coal Component | Design Coal (4,5) | Other North Dakota Lignites (23,24) | | |
		Mean	Standard Deviation	Number of Data Points
Sulfur, % (dry basis)	1.3	0.64	0.08	Not Available
Ash, % (dry basis)	11.1	9.0	2.7	Not Available
Trace Elements, ppmw (dry basis)				
Ag	--	0.049	0.03	10
As	16	5.24	0.50	7
B	100	64.2	32	10
Ba	--	501	272	10
Be	0.50	0.31	0.25	10
Cd	C.34	0.35	0.48	7
Cr	--	7.52	12	10
Cu	37	11.3	0.13	10
F	34	27.5	17	7
Hg	0.33	0.094	0.05	7
Ni	19	3.6	3.0	10
Pb	88	2.31	0.06	10
Se	1.4	0.59	0.63	7
V	--	7.23	3.8	10
Zn	18	3.84	0.84	9

age, sulfur emissions from the power boilers and FGD sludge production rates
are likely to be proportionately lower. Similarly, since the design trace
element concentrations were selected conservatively, average trace element
emission rates in all coal derived gaseous and solid waste streams would
typically be lower in proportion to the ratio of the mean-to-design concen-
tration. It should be noted, however, that such extrapolations cannot be
made with respect to trace element concentrations in leachates or other liquid
waste streams. Ash and slag production rates are, on the average, likely to
be overestimated by 20 to 30% consistent with the mean-to-design ash concen-
tration ratio.

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