

DE-FE0000663: HYDROGEN ENERGY CALIFORNIA, LLC

Hydrogen Energy California (HECA) Project

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3.0 PROJECT DESIGN

3.1 INTRODUCTION AND PROJECT OVERVIEW

3.1.1 Introduction

In January 2012 Hydrogen Energy California LLC (HECA LLC) contracted with Fluor Enterprises, Inc. to perform Front End Engineering and Design (FEED) for the Hydrogen Energy California Project (hereafter referred to as HECA or the Project). HECA LLC is owned by SCS Energy California LLC. The FEED was performed over the period between January 2012 and the end of March 2013.

HECA would be a first-of-its-kind, state-of-the-art facility that would produce electricity and other useful products for California. The Project would have dramatically lower carbon emissions compared to traditional facilities.

According to the U.S. Department of Energy:

The project will be among the cleanest of any commercial solid fuel power plant built or under construction and will significantly exceed the emission reduction targets for 2020 established under the Energy Policy Act of 2005. In addition, emissions from the project plant will be well below the California regulation requiring baseload plants to emit less greenhouse gases than comparably-sized natural gas combined cycle power plants (U.S. Department of Energy, HECA Project Facts, November 2011).

HECA would achieve these important environmental objectives by capturing carbon from its processes and transporting the carbon dioxide for storage, also known as sequestration, in secure geologic formations within the earth.

The U.S. Department of Energy recognized HECA's importance in advancing carbon capture and sequestration:

A need exists to further develop carbon management technologies that capture and store or beneficially reuse carbon dioxide (CO₂) that would otherwise be emitted into the atmosphere from coal-based electric power generating facilities. Carbon capture and storage (CCS) technologies offer great potential for reducing CO₂ emissions and mitigating global climate change, while minimizing the economic impacts of the solution. Once demonstrated, the technologies can be readily considered in the commercial market-place by the electric power industry (U.S. Department of Energy, HECA Project Facts, November 2011).

FEED development involved a combination of “open-art” engineering and Licensor prepared engineering. Technical data developed by Technology Licensors was provided in the form of Process Design Packages (PDPs). These PDPs contain Confidential Licensed Technology that is protected from FOIA release by License Agreements and/or by Non-Disclosure Agreements. Due to the requirements of these Agreements, this report provides non-confidential summary level information for the process units that utilize Licensor data. More detailed information is provided for the “open-art” process units.

This Project Design Report is organized as summarized below:

- Project Overview and Location
- Overall Block Flow Diagram with Plant Performance and Heat & Material Balance and Emission Summary data
- Project Design Basis
- System Descriptions followed by corresponding Process Flow Diagrams
- Plot Plan and Equipment List
- Estimated Capital and Operating Costs
- A “General” section providing additional design related documentation

The ongoing design development and refinement that took place during the course of executing FEED on this first-of-a-kind project identified several design enhancements and/or needed changes. Some of these changes were incorporated into the FEED design. Those changes that were identified after FEED engineering cut-off were not incorporated. These “Late Changes” were to be addressed in a subsequent phase of engineering. The project estimate includes a rough-order-of-magnitude allowance for these post cut-off changes.

A summary level project description and information on the project site and its location are provided in the following two sections (3.1.2 and 3.1.3 respectively).

3.1.2 Project Overview

HECA is an Integrated Gasification Combined-Cycle (IGCC) “polygeneration” project. The Project gasifies a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend to produce synthesis gas (syngas). Syngas produced via gasification is purified to hydrogen-rich fuel, which is used to generate low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based products in an integrated Manufacturing Complex, and carbon dioxide (CO₂) for use in enhanced oil recovery (EOR).

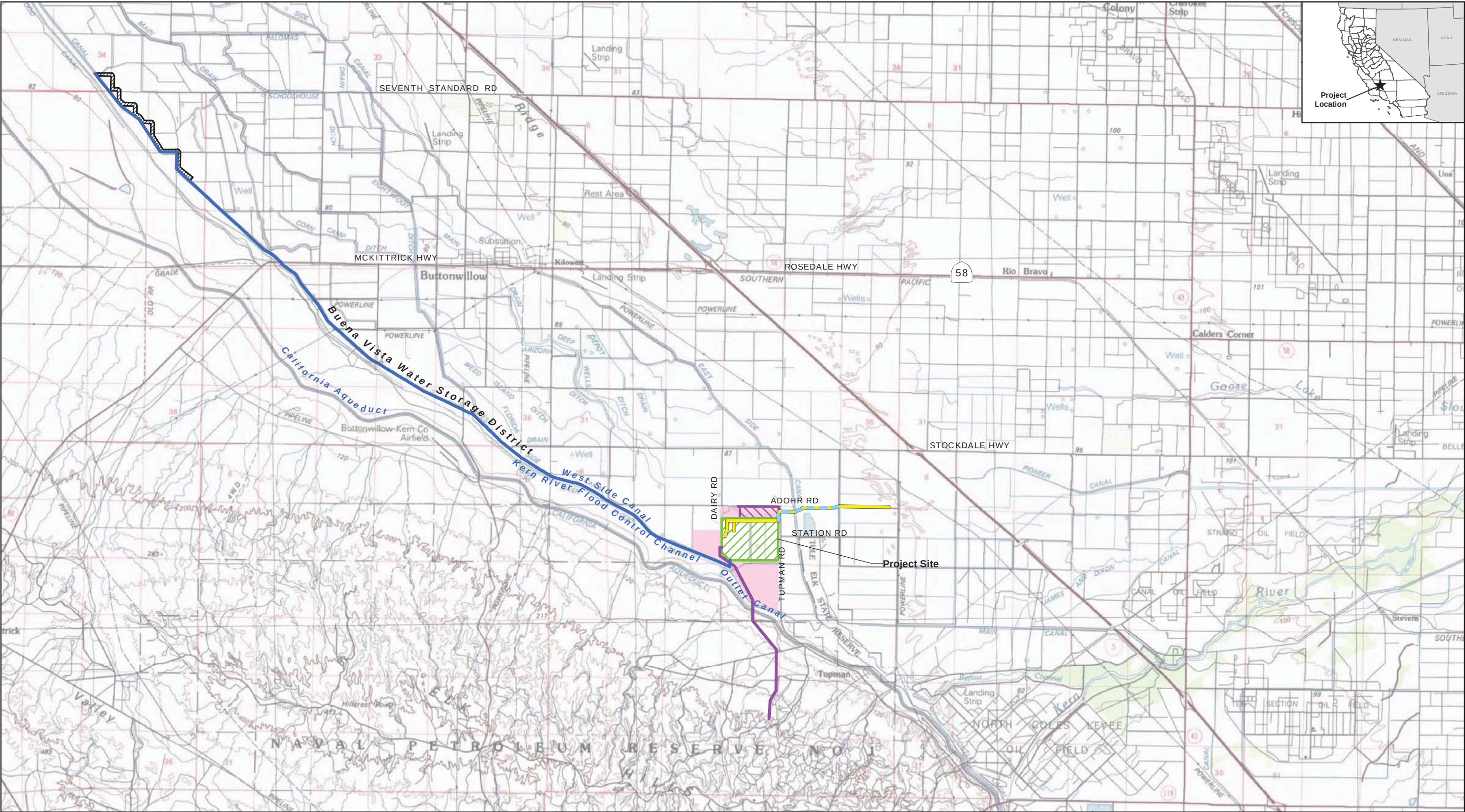
The power and products produced by HECA have a lower carbon footprint compared to power and products produced from more traditional fossil fuel facilities. This low-carbon footprint is achieved by capturing more than 90 percent of the CO₂ in the production of the hydrogen fuel and transporting it for use in EOR, which results in simultaneous sequestration (storage) of the CO₂ in a secure geologic formation in the adjacent Elk Hills Oil Field (EHOF), a hydrocarbon producing area.

Highlights of HECA as conceived during the execution of FEED are as follows:

- The Project is designed to operate on a fuel blend consisting of 75 percent western sub-bituminous coal and 25 percent California petcoke based on thermal input to the gasifier on a higher heating value (HHV) basis.
- The feedstocks are gasified to produce syngas that is further processed and cleaned to produce hydrogen-rich fuel.
- More than 90 percent of the carbon in the raw syngas is captured in a high-purity CO₂ stream during steady-state operation.
- High purity CO₂ is compressed and transported by pipeline to the EHOF for injection into deep underground hydrocarbon reservoirs for CO₂ EOR.
- The Combined Cycle Power Block produces over 420 megawatts (MW) of gross power, which yields during periods of maximum power production over 270 MW of low-carbon baseload electricity to the grid
- An integrated Manufacturing Complex produces approximately 1 million tons per year of low-carbon nitrogen-based products, including urea, urea ammonium nitrate (UAN), and anhydrous ammonia, to be used in agricultural, transportation, and industrial applications.

3.1.3 Location

The HECA project site consists of 453 acres and is located approximately 7 miles west of the outermost edge of the city of Bakersfield and 1.5 miles northwest of the unincorporated community of Tupman in western Kern County, California. The project site is shown in Figure 3-1, Project Location Map. A computer rendering of the project is shown in Figure 3-2, Project Site Rendering.



Project Site Construction Staging Area Controlled Area BWSD Well Field Carbon Dioxide Natural Gas¹ Potable Water Process Water Railroad¹ Transmission Note: 1. Feature temporarily designated as confidential 0 1 2 MILES	Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report Source Document: Amended AFC (08-AFC-8) Fig. 2-7 (May 2012)	hydrogen energy[®] california HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA

Source: USGS (30"x60" quads: Taft 1982, Delano 1982). Created using TOPOI, ©2006 National Geographic Maps, All Rights Reserved. Kern County and State of California (proposed and approved projects).



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HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

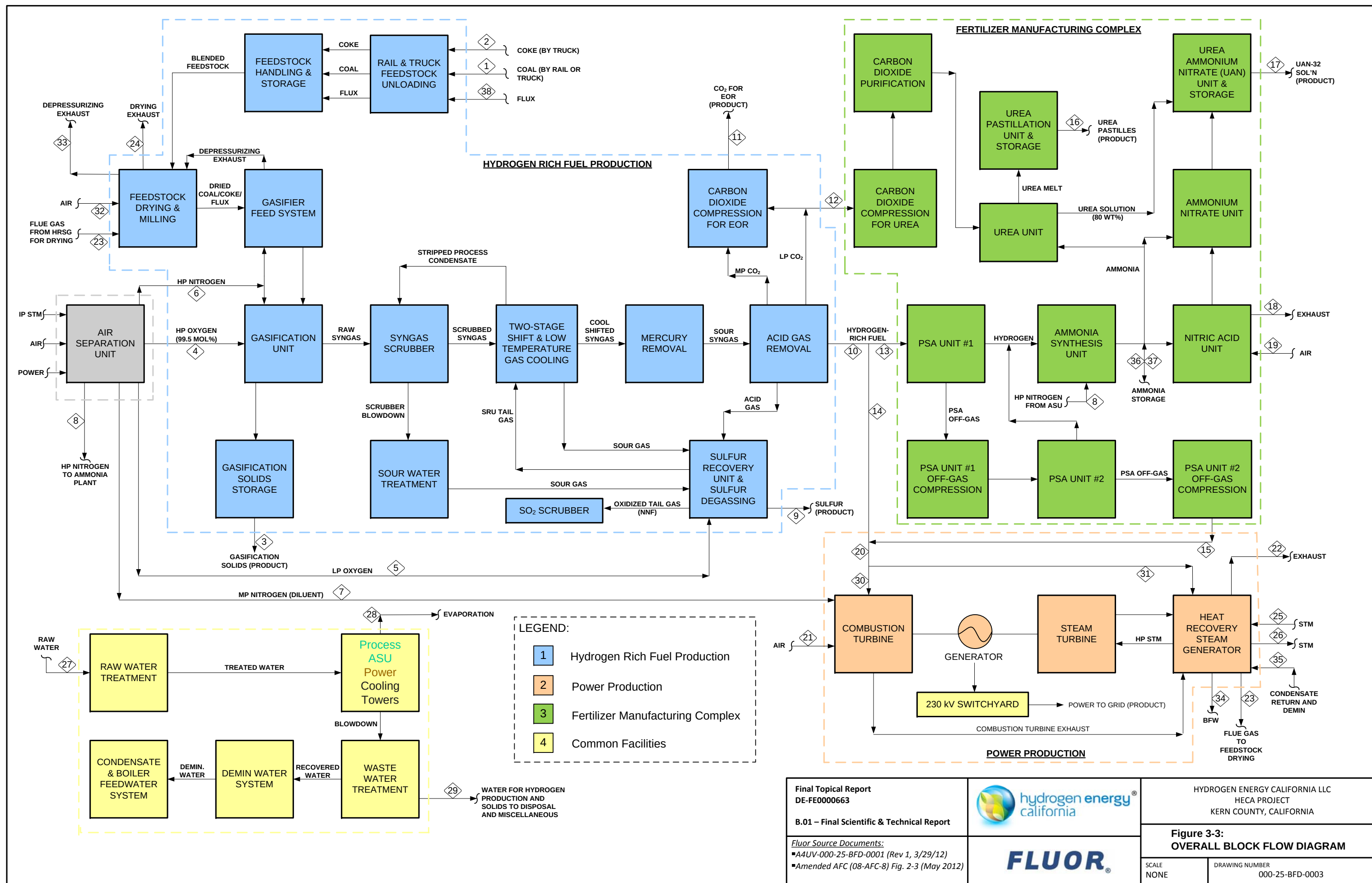
Source Document:
Amended AFC (08-AFC-8) Project
Refinements Revised Fig.1-4 (Oct 2013)

Figure 3-2: PROJECT SITE RENDERING

3.2 OVERALL BLOCK FLOW DIAGRAM

The Overall Block Flow Diagram (drawing number 000-25-BFD-0003) provides an overview of the project facilities, plant configuration, and major feed, product, and utility streams.

Corresponding heat and material balance (H&MB) information for the streams that are numbered on the block flow diagram (BFD) is provided in Section 3.4. The BFD is included as Figure 3-3.



3.3 PLANT PERFORMANCE

The six (6) plant operating cases are shown in Table 3-1 and are further described in the narrative and figures that follow the table. The plant performance associated with these 6 operating cases is summarized in Tables 3-2 and 3-3.

Table 3-1: Overall Operating Cases

Case Element	Case Number					
	1	2	3	4	5	6
Combustion Turbine Fuel	H ₂ -Rich Fuel (Syngas)	H ₂ -Rich Fuel (Syngas)	H ₂ -Rich Fuel (Syngas)	H ₂ -Rich Fuel (Syngas)	H ₂ -Rich Fuel (Syngas)	H ₂ -Rich Fuel (Syngas)
Operating Mode	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Combustion Turbine at Base Load (<i>See Note</i>)	Yes	No	Yes	No	Yes	No
Syngas Duct Burner Firing	Yes	No	Yes	No	Yes	No
Ambient Temperature (°F)	97	97	39	39	65	65
Evaporative Cooling	Yes	Yes	No	No	No	No

Note: Base Load makes reference to combustion turbine manufacturer's maximum continuous operating condition at the given ambient air temperature.

Gasification through AGR operate at 100% for all 6 cases.

Cases 1, 3 and 5 represent “on-peak” operation at various ambient temperatures where power export is maximized and ammonia production is turned down. On-peak operation occurs for 16 hours per day and is illustrated below in Figure 3-4. 71.3% of the hydrogen-rich fuel (syngas) goes to the Power Block, with the balance to the Ammonia Plant. The PSA and Ammonia Plant operate at 60%; the Power Block operates at 100%. The Urea and UAN Complex operate at 100% and inventory draws down from intermediate ammonia storage.

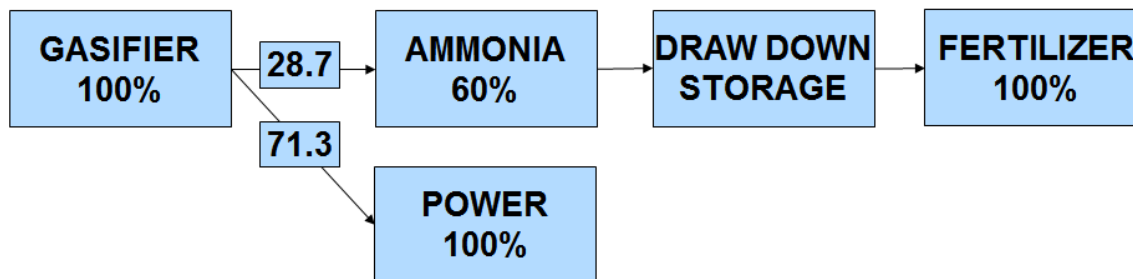


Figure 3-4: On-Peak Operating Mode

Cases 2, 4 and 6 represent “off-peak” operation at various ambient temperatures where ammonia production is maximized and power export is turned down. Off-peak operation occurs for 8 hours per day and is illustrated below in Figure 3-5. 52.1% of the syngas goes to the Power Block, with the balance to the Ammonia Unit. The PSA and Ammonia Plant operate at 100%; the Power Block operates at 65%. The Urea and UAN Complex operate at 100% and inventory builds in intermediate ammonia storage.

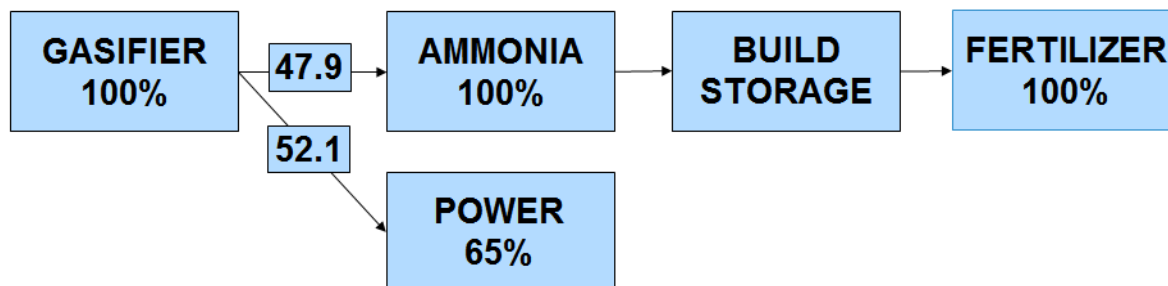


Figure 3-5: Off-Peak Operating Mode

On a daily average basis, 64.9% of the syngas energy is used to produce power.

Table 3-2: Plant Performance Summary

Parameter	Units	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
		On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Ambient Temperature	°F	97.0	97.0	39.0	39.0	65.0	65.0
Feeds							
Coal, As Received	sTPD	4,623	4,623	4,623	4,623	4,623	4,623
Petcoke, As Received	sTPD	1,151	1,151	1,151	1,151	1,151	1,151
Flux, As Received (3wt%)	sTPD	173	173	173	173	173	173
Oxygen to Gasification, 99.5mol%	sTPD	3,529	3,529	3,529	3,529	3,529	3,529
Raw Water Consumption	GPM	5,133	5,133	4,604	4,604	4,604	4,604
Intermediate Products							
Ammonia, 99.9 wt%	sTPD	1,251	2,089	1,251	2,089	1,251	2,089
Urea Melt for Pastillation (Urea + Biuret)	sTPD	1,701	1,701	1,701	1,701	1,701	1,701
Urea Solution for UAN Solution (Urea + Biuret)	sTPD	499	499	499	499	499	499
Final Products							
Gross Power	MW	421.8	320.9	409.1	309.2	416.0	315.2
Auxiliary Power	MW	150.5	164.1	150.5	164.1	150.5	164.1
Net Power Export	MW	271.3	156.8	258.6	145.1	265.5	151.1
Urea Pastilles	sTPD	1,703	1,703	1,703	1,703	1,703	1,703
Urea Ammonium Nitrate (UAN-32) Solution	sTPD	1,404	1,404	1,404	1,404	1,404	1,404
Carbon Dioxide to Pipeline, Total Stream Basis	sTPD	9,158	9,158	9,158	9,158	9,158	9,158
Degassed Elemental Sulfur	sTPD	101	101	101	101	101	101
Gasification Solids, Dry Basis	sTPD	943	943	943	943	943	943

Table 3-3: Plant Performance Details – Generation and Auxiliary Loads

Parameter	Units	Hydrogen-Rich Fuel						Daily Average
		Maximum Power Production	Maximum Ammonia Production	Maximum Power Production	Maximum Ammonia Production	Maximum Power Production	Maximum Ammonia Production	
		On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	
Ambient Temperature	°F	97	97	39	39	65	65	65
Gross Power Generation (CT/ST) ⁽¹⁾	MW	421.8	320.9	409.1	309.2	416.0	315.2	382.4
Power Generation Fertilizer Contribution	MW	3.5	11.3	3.5	11.3	3.5	11.3	6.1
Power Generation Less Fertilizer Contribution	MW	418.3	309.6	405.6	297.9	412.5	303.9	376.3
Total Auxiliary Load	MW	150.5	164.1	150.5	164.1	150.5	164.1	155.0
Gasification	MW	12.1	12.1	12.1	12.1	12.1	12.1	12.1
Shift and LTGC	MW	0.9	0.9	0.9	0.9	0.9	0.9	0.9
AGR	MW	19.3	19.3	19.3	19.3	19.3	19.3	19.3
SRU	MW	2.0	2.0	2.0	2.0	2.0	2.0	2.0
EOR CO2 Compression	MW	36.1	36.1	36.1	36.1	36.1	36.1	36.1
PSA and Ammonia Units	MW	33.3	46.8	33.3	46.8	33.3	46.8	37.8
CO2 Purification	MW	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Urea/UAN	MW	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Power Block	MW	5.7	5.4	5.7	5.4	5.7	5.4	5.6
Water Treatment	MW	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Power Cooling Tower	MW	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Process Cooling Tower	MW	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Fertilizer Storage/Handling	MW	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Other Supporting Systems	MW	8.3	8.7	8.3	8.7	8.3	8.7	8.4
Net Power Export	MW	271	157	259	145	266	151	227

(1) The gross power output of the Combined Cycle Power Block may be as much as 431 megawatts (MW) of gross power generation. The additional gross power output is the result of efficiency optimization and improvement in heat recovery that occurred post-completion of FEED. There is no additional fuel input or emissions expected with this engineering optimization.

3.4 OVERALL HEAT & MATERIAL BALANCE

H&MB information for streams identified on the Overall Block Flow Diagram (drawing number 000-25-BFD-0003) is provided in the tables below.

Gasifier Feedstock stream data (Streams 1, 2, 38) is the same for all cases. The total feedstock higher heating value (HHV) is 4,752 MMBtu/hr. The lower heating value (LHV) is 4,591 MMBtu/hr, with a resulting HHV/LHV ratio of 1.035.

Gasifier Solids (Stream 3) stream data is also the same for all cases.

The data for the other numbered streams is provided for the average ambient “On-Peak” and “Off-Peak” operating conditions (Cases 5 and 6, respectively).

Table 3-4: Gasifier Feedstocks

Stream ID	1	2	38
Description	Coal	Coke	Flux
<u>Ultimate Analysis (wt% dry)</u>	-	-	(1)
Carbon	60.40%	84.40%	-
Hydrogen	4.50%	4.00%	-
Nitrogen	1.00%	4.00%	-
Sulfur	1.09%	6.00%	-
Oxygen	11.71%	0.60%	-
Ash	21.30%	1.00%	-
Total	100.00%	100.00%	-
Moisture (wt%, AR)	14.80%	15.00%	-
HHV (Btu/lb, dry)	10,860	14,579	-
lb/hr (AR)	385,225	95,876	14,448
lb/hr (dry)	328,212	81,495	14,159
MMBtu/hr, HHV	3,564.4	1,188.1	0.0
Percentage	75.00%	25.00%	0.00%
Dry Basis, lb/hr			
Carbon	198,240	68,781	1,647
Hydrogen	14,770	3,260	0
Nitrogen	3,282	3,260	0
Sulfur	3,578	4,890	0
Oxygen	38,434	489	4,388
Ash	69,909	815	8,124
Total	328,212	81,495	14,159
Water, lb/hr	57,013	14,381	289
As-Received (AR) Basis, lb/hr			
Carbon	198,240	68,781	1,647
Hydrogen	21,147	4,868	32
Nitrogen	3,282	3,260	0
Sulfur	3,578	4,890	0
Oxygen	89,070	13,262	4,645
Ash	69,909	815	8,124
Total	385,225	95,876	14,448

(1) As-received analysis of Fluxant is: 95wt% CaCO₃; 2wt% Moisture; 3wt% Ash.

Table 3-5: Gasifier Solids

Stream ID	3
Description	Gasifier Solids
Total Mass Flow (lb/hr)	78,619



Table 3-6: Overall H&MB - Case 5 (On-Peak, 65 °F Ambient Temperature)

Stream ID					4			5			6			7			8		
Description					HP Oxygen to Gasifier			LP Oxygen to SRU			HP Nitrogen to Gasifier			MP Nitrogen (Diluent) to CTG			HP Nitrogen to Ammonia Synthesis		
Phase					Vapor			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methane		CH ₄	16.042	909.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	0.10%	9.18	257	0.10%	0.15	4	99.90%	9,474.52	265,414	99.90%	19,623.26	549,716	99.90%	3,059.94	85,719
Oxygen		O ₂	31.999	0.0	99.50%	9,136.09	292,344	99.50%	149.25	4,776	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.40%	36.73	1,467	0.40%	0.60	24	0.10%	9.48	379	0.10%	19.64	785	0.10%	3.06	122
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	9,182.00	294,068	100.00%	150.00	4,804	100.00%	9,484.00	265,793	100.00%	19,642.90	550,500	100.00%	3,063.00	85,842
Temperature							275			70			158			180			100
Pressure							819.0			89.5			892.0			438.0			483.6
Average Molecular Weight							32.03			32.03			28.03			28.03			28.03
Energy																			
mSCFH							3,480.0			56.9			3,594.4			7,444.7			1,160.9
HHV							0			0			0			0			0
Btu/SCF							0			0			0			0			0
LHV							0			0			0			0			0
Btu/SCF							0			0			0			0			0



Table 3-6: Overall H&MB – Case 5 (On-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					9			10			11			12			13		
Description					Sulfur (Product)			Total Hydrogen Rich Gas			CO2 for EOR			LP CO2 to Fertilizer Manufacturing			Hydrogen Rich Gas to PSA		
Phase					Liquid			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide	CO	28.010	320.5	320.5	0.00%	0.00	0	1.83%	681.91	19,100	0.07%	12.20	342	0.00%	0.00	0	1.83%	224.19	6,280
Hydrogen	H ₂	2.0159	273.8	324.2	0.00%	0.00	0	79.84%	29,751.52	59,976	0.28%	48.80	98	0.00%	0.00	0	79.84%	9,781.20	19,718
Carbon Dioxide	CO ₂	44.010	0.0	0.0	0.00%	0.00	0	2.00%	745.26	32,799	99.18%	17,286.08	760,752	99.97%	3,028.09	133,265	2.00%	245.02	10,783
Water	H ₂ O	18.015	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methane	CH ₄	16.042	909.4	1,010.0	0.00%	0.00	0	1.16%	432.25	6,934	0.16%	27.89	447	0.01%	0.30	5	1.16%	142.11	2,280
Methanol	CH3OH	32.042	766.1	866.7	0.00%	0.00	0	0.01%	3.73	119	0.02%	3.49	112	0.02%	0.61	19	0.01%	1.23	39
Ammonia	NH ₃	17.031	359.0	434.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen	N ₂	28.013	0.0	0.0	0.00%	0.00	0	15.05%	5,608.08	157,102	0.27%	47.06	1,318	0.00%	0.00	0	15.05%	1,843.78	51,651
Oxygen	O ₂	31.999	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide	H ₂ S	34.082	586.8	637.1	0.00%	0.00	0	0.00%	0.00	0	0.01%	1.74	59	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide	COS	60.076	622.1	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon	Ar	39.948	0.0	0.0	0.00%	0.00	0	0.11%	40.99	1,637	0.01%	1.74	70	0.00%	0.00	0	0.11%	13.48	538
Urea	CH4N2O	60.057	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret	(H2NCO)2-NH	103.080	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate	(NH4)(NO3)	80.043	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur	S	32.066	n.a.	n.a	100.00%	262.26	8,410	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	262.26	8,410	100.00%	37,263.00	277,668	100.00%	17,429.00	763,198	100.00%	3,029.00	133,289	100.00%	12,251.00	91,289
Temperature					deg F			280			88			110			88		
Pressure					psia			114.5			517.6			2580.0			18.8		
Average Molecular Weight					lb/lbmol			32.07			7.45			43.79			44.00		
Energy																			
mSCFH					99.4			14,122.7			6,605.6			1,148.0			4,643.1		
HHV					0			3,905			20			0			1,284		
Btu/SCF					0			277			3			0			277		
LHV					0			3,320			18			0			1,092		
Btu/SCF					0			235			3			0			235		



Table 3-6: Overall H&MB – Case 5 (On-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					14			15			16			17			18		
Description					Hydrogen Rich Gas to Power Block			PSA Off-Gas			Urea Pastilles			UAN-32 Solution			Exhaust from Nitric Acid Unit		
Phase					Vapor			Vapor			Solid			Liquid			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	1.83%	457.72	12,821	7.38%	224.57	6,290	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	79.84%	19,969.58	40,256	19.29%	586.99	1,183	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	2.00%	500.24	22,015	8.05%	244.96	10,781	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	0.00%	0.00	0	0.00%	0.00	0	0.74%	17.53	316	49.41%	1,308.39	23,571	0.60%	35.96	648
Methane		CH ₄	16.042	909.4	1.16%	290.14	4,655	4.65%	141.50	2,270	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.01%	2.50	80	0.02%	0.61	20	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.11%	2.61	44	0.06%	1.59	27	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	15.05%	3,764.31	105,451	60.17%	1,830.97	51,292	0.00%	0.00	0	0.00%	0.00	0	95.28%	5,710.13	159,961
Oxygen		O ₂	31.999	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	2.93%	175.59	5,619
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.11%	27.51	1,099	0.44%	13.39	535	0.00%	0.00	0	0.00%	0.00	0	1.19%	71.32	2,849
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	98.68%	2,337.67	140,393	25.95%	687.16	41,269	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.47%	11.13	1,148	0.12%	3.18	328	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	24.46%	647.71	51,844	0.00%	0.00	0
Sulfur		S	32.066	n.a.				0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	25,012.00	186,377	100.00%	3,043.00	72,371	100.00%	2,368.94	141,900	100.00%	2,648.03	117,039	100.00%	5,993.00	169,076
Temperature							88			429.4			65			65			270
Pressure							517.6			517.6			14.5			14.5			14.6
Average Molecular Weight							7.45			23.78			59.90			44.20			28.21
Energy																			
							9,479.5			1,153.3			897.8			1,003.6			2,271.3
HHV							2,621			154			0			0			0
							277			133			0			0			0
LHV																			
							2,229			137			0			0			0
							235			119			0			0			0



Table 3-6: Overall H&MB – Case 5 (On-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					19			20			21			22			23		
Description					Air to Nitric Acid Unit			Fuel Gas (Hydrogen Rich gas + PSA Off-gas)			Air to CTG			Exhaust from HRSG			Flue Gas to Feedstock Drying		
Phase					Vapor			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide	CO	28.010	320.5	320.5	0.00%	0.00	0	2.43%	682.29	19,111	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen	H ₂	2.0159	273.8	324.2	0.00%	0.00	0	73.27%	20,556.58	41,440	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide	CO ₂	44.010	0.0	0.0	0.04%	2.94	129	2.66%	745.20	32,796	0.04%	56.84	2,501	0.96%	1,652.40	72,721	0.96%	262.38	11,547
Water	H ₂ O	18.015	0.0	0.0	1.13%	83.12	1,497	0.00%	0.00	0	1.13%	1,827.00	32,914	12.07%	20,775.51	374,277	12.07%	3,298.86	59,430
Methane	CH ₄	16.042	909.4	1,010.0	0.00%	0.00	0	1.54%	431.64	6,925	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol	CH ₃ OH	32.042	766.1	866.7	0.00%	0.00	0	0.01%	3.11	100	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia	NH ₃	17.031	359.0	434.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen	N ₂	28.013	0.0	0.0	77.20%	5,678.83	159,084	19.94%	5,595.28	156,743	77.20%	125,372.80	3,512,128	75.12%	129,300.45	3,622,156	75.12%	20,531.12	575,148
Oxygen	O ₂	31.999	0.0	0.0	20.71%	1,523.43	48,748	0.00%	0.00	0	20.71%	33,633.04	1,076,217	11.06%	19,037.05	609,163	11.06%	3,022.82	96,727
Hydrogen Sulfide	H ₂ S	34.082	586.8	637.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide	COS	60.076	622.1	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon	Ar	39.948	0.0	0.0	0.93%	68.41	2,733	0.15%	40.90	1,634	0.93%	1,510.32	60,334	0.79%	1,352.39	54,025	0.79%	214.74	8,578
Urea	CH ₄ N ₂ O	60.057	n.a.	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret	(H ₂ NCO) ₂ -NH	103.080	n.a.	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate	(NH ₄)(NO ₃)	80.043	n.a.	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur	S	32.066	n.a.	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.01%	7,356.00	212,192	100.00%	28,055.00	258,748	100.00%	162,400.00	4,684,095	100.00%	172,125.20	4,732,341	100.00%	27,331.10	751,430
Temperature							97			97			65			200			517
Pressure							14.5			498.4			14.5			15.2			14.5
Average Molecular Weight							28.85			9.22			28.84			27.49			27.49
Energy																			
mSCFH							2,787.9			10,632.8			61,549.6			65,235.5			10,358.5
HHV							0			2,775			0			0			0
Btu/SCF							0			261			0			0			0
LHV							0			2,366			0			0			0
Btu/SCF							0			222			0			0			0



Table 3-6: Overall H&MB – Case 5 (On-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					24			25			26			27			28		
Description					Drying Exhaust			Steam to HRSG			Steam from HRSG			Raw Water			Evaporation from Cooling Towers		
Phase					Vapor			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	0.88%	262.37	11,547	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	18.64%	5,557.52	100,120	100.00%	34,124.90	614,770	100.00%	15,942.00	287,200	100.00%	128,113.17	2,307,995	100.00%	105,027.18	1,892,094
Methane		CH ₄	16.042	909.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	68.66%	20,472.17	573,497	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Oxygen		O ₂	31.999	0.0	11.10%	3,309.47	105,899	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.72%	213.18	8,516	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	29,815.00	799,579	100.00%	34,124.90	614,770	100.00%	15,942.00	287,200	100.00%	128,113.17	2,307,995	100.00%	105,027.18	1,892,094
Temperature							200									60			
Pressure							14.5									114.5			
Average Molecular Weight							26.82			18.02			18.02			18.02			18.02
Energy																			
							11,299.9									48,554.9			39,805.3
HHV							0			817			367			0			0
							0									0			0
LHV							0			0			0			0			0
							0									0			0



Table 3-6: Overall H&MB – Case 5 (On-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					29			30			31			32			33		
Description					Water Consumed for H2 Production, ZLD solids & misc			Fuel Gas to CTG			Excess Fuel Gas to Duct Burner			Air for Pulverizer Sealing			Depressurizing Exhaust Gas		
Phase					Vapor			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	0.00%	0.00	0	2.43%	605.44	16,959	2.43%	76.85	2,153	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	0.00%	0.00	0	73.27%	18,241.21	36,772	73.27%	2,315.37	4,668	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	0.00%	0.00	0	2.66%	661.27	29,102	2.66%	83.94	3,694	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	100.00%	23,085.99	415,901	0.00%	0.00	0	0.00%	0.00	0	1.20%	16.15	291	0.00%	0.00	0
Methane		CH ₄	16.042	909.4	0.00%	0.00	0	1.54%	383.02	6,145	1.54%	48.62	780	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.00%	0.00	0	0.01%	2.76	88	0.01%	0.35	11	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	0.00%	0.00	0	19.94%	4,965.06	139,089	19.94%	630.22	17,655	77.20%	1,039.11	29,109	99.90%	3,651.35	102,287
Oxygen		O ₂	31.999	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	20.70%	278.62	8,916	0.00%	0.00	0
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.00%	0.00	0	0.15%	36.30	1,450	0.15%	4.61	184	0.90%	12.11	484	0.10%	3.66	146
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	23,085.99	415,901	100.00%	24,895.05	229,604	100.00%	3,159.95	29,144	100.00%	1,346.00	38,800	100.00%	3,655.00	102,433
Temperature							65			97			97			65			158
Pressure							14.5			498.4			498.0			14.5			14.5
Average Molecular Weight							18.02			9.22			9.22			28.83			28.03
Energy																			
mSCFH										9,435.2			1,197.6			510.1			1,385.2
HHV										2,462			313			0			0
Btu/SCF										261			261			0			0
LHV																			
mm Btu/h										2,099			266			0			0
Btu/SCF										222			222			0			0



Table 3-6: Overall H&MB – Case 5 (On-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					34			35			36			37		
Description					BFW to Process			Process Condensate Return			Ammonia to Storage			Ammonia from Storage		
Phase					Liquid			Liquid			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	100.00%	59,055.50	1,063,901	100.00%	40,872.50	736,330	0.00%	0.00	0	0.00%	0.00	0
Methane		CH ₄	16.042	909.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	100.00%	6,122.00	104,261	100.00%	7,472.00	127,252
Nitrogen		N ₂	28.013	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Oxygen		O ₂	31.999	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	59,055.50	1,063,901	100.00%	40,872.50	736,330	100.00%	6,122.00	104,261	100.00%	7,472.00	127,252
Temperature																
Pressure																
Average Molecular Weight							18.02			18.02			17.03			17.03
Energy																
HHV							292			52			2,320.2			2,831.9
LHV													1,008			1,230
													434			434
													833			1,017
													359			359



Table 3-7: Overall H&MB - Case 6 (Off-Peak, 65 °F Ambient Temperature)

Stream ID					4			5			6			7			8		
Description					HP Oxygen to Gasifier			LP Oxygen to SRU			HP Nitrogen to Gasifier			MP Nitrogen (Diluent) to CTG			HP Nitrogen to Ammonia Synthesis		
Phase					Vapor			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide CO		28.010	320.5	320.5	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen H ₂		2.0159	273.8	324.2	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide CO ₂		44.010	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water H ₂ O		18.015	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methane CH ₄		16.042	909.4	1,010.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol CH ₃ OH		32.042	766.1	866.7	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia NH ₃		17.031	359.0	434.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen N ₂		28.013	0.0	0.0	0.10%	9.18	257	0.10%	0.15	4	99.90%	9,474.52	265,414	99.90%	13,755.89	385,350	99.90%	5,099.90	142,866
Oxygen O ₂		31.999	0.0	0.0	99.50%	9,136.09	292,344	99.50%	149.25	4,776	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide H ₂ S		34.082	586.8	637.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide COS		60.076	622.1	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon Ar		39.948	0.0	0.0	0.40%	36.73	1,467	0.40%	0.60	24	0.10%	9.48	379	0.10%	13.77	550	0.10%	5.11	204
Urea CH ₄ N ₂ O		60.057	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret (H ₂ NCO) ₂ -NH		103.080	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate (NH ₄)(NO ₃)		80.043	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur S		32.066	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	9,182.00	294,068	100.00%	150.00	4,804	100.00%	9,484.00	265,793	100.00%	13,769.66	385,900	100.00%	5,105.00	143,070
Temperature deg F							275			70			158			200			100
Pressure psia							819.0			89.5			892.0			438.0			483.6
Average Molecular Weight lb/lbmol							32.03			32.03			28.03			28.03			28.03
Energy																			
mSCFH							3,480.0			56.9			3,594.4			5,218.7			1,934.8
HHV mm Btu/h							0			0			0			0			0
Btu/SCF							0			0			0			0			0
LHV mm Btu/h							0			0			0			0			0
Btu/SCF							0			0			0			0			0



Table 3-7: Overall H&MB – Case 6 (Off-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					9			10			11			12			13		
Description					Sulfur (Product)			Total Hydrogen Rich Gas			CO2 for EOR			LP CO2 to Fertilizer Manufacturing			Hydrogen Rich Gas to PSA		
Phase					Liquid			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide	CO	28.010	320.5	320.5	0.00%	0.00	0	1.83%	681.91	19,100	0.07%	12.20	342	0.00%	0.00	0	1.83%	373.65	10,466
Hydrogen	H ₂	2.0159	273.8	324.2	0.00%	0.00	0	79.84%	29,751.52	59,976	0.28%	48.80	98	0.00%	0.00	0	79.84%	16,301.73	32,862
Carbon Dioxide	CO ₂	44.010	0.0	0.0	0.00%	0.00	0	2.00%	745.26	32,799	99.18%	17,286.08	760,752	99.99%	3,028.70	133,291	2.00%	408.36	17,972
Water	H ₂ O	18.015	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methane	CH ₄	16.042	909.4	1,010.0	0.00%	0.00	0	1.16%	432.25	6,934	0.16%	27.89	447	0.01%	0.30	5	1.16%	236.85	3,800
Methanol	CH ₃ OH	32.042	766.1	866.7	0.00%	0.00	0	0.01%	3.73	119	0.02%	3.49	112	0.00%	0.00	0	0.01%	2.04	65
Ammonia	NH ₃	17.031	359.0	434.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen	N ₂	28.013	0.0	0.0	0.00%	0.00	0	15.05%	5,608.08	157,102	0.27%	47.06	1,318	0.00%	0.00	0	15.05%	3,072.91	86,083
Oxygen	O ₂	31.999	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide	H ₂ S	34.082	586.8	637.1	0.00%	0.00	0	0.00%	0.00	0	0.01%	1.74	59	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide	COS	60.076	622.1	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon	Ar	39.948	0.0	0.0	0.00%	0.00	0	0.11%	40.99	1,637	0.01%	1.74	70	0.00%	0.00	0	0.11%	22.46	897
Urea	CH ₄ N ₂ O	60.057	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret	(H ₂ NCO) ₂ -NH	103.080	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate	(NH ₄)(NO ₃)	80.043	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur	S	32.066	n.a.	n.a	100.00%	262.26	8,410	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	262.26	8,410	100.00%	37,263.00	277,668	100.00%	17,429.00	763,198	100.00%	3,029.00	133,296	100.00%	20,418.00	152,145
Temperature					deg F			88			110			88			88		
Pressure					psia			517.6			2580.0			18.8			517.6		
Average Molecular Weight					lb/lbmol			7.45			43.79			44.01			7.45		
Energy					mSCFH			14,122.7			6,605.6			1,148.0			7,738.4		
HHV					mm Btu/h			3,905			20			0			2,140		
					Btu/SCF			277			3			0			277		
LHV					mm Btu/h			3,320			18			0			1,819		
					Btu/SCF			235			3			0			235		



Table 3-7: Overall H&MB – Case 6 (Off-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					14			15			16			17			18		
Description					Hydrogen Rich Gas to Power Block			PSA Off-Gas			Urea Pastilles			UAN-32 Solution			Exhaust from Nitric Acid Unit		
Phase					Vapor			Vapor			Solid			Liquid			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	1.83%	308.26	8,634	7.38%	374.31	10,485	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	79.84%	13,449.05	27,112	19.29%	978.39	1,972	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	2.00%	336.90	14,827	8.05%	408.30	17,969	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	0.00%	0.00	0	0.00%	0.00	0	0.74%	17.53	316	49.41%	1,308.39	23,571	0.60%	35.96	648
Methane		CH ₄	16.042	909.4	1.16%	195.40	3,135	4.65%	235.85	3,784	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.01%	1.68	54	0.02%	1.01	33	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.11%	2.61	44	0.06%	1.59	27	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	15.05%	2,535.17	71,019	60.17%	3,051.82	85,492	0.00%	0.00	0	0.00%	0.00	0	95.28%	5,710.13	159,961
Oxygen		O ₂	31.999	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	2.93%	175.59	5,619
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.11%	18.53	740	0.44%	22.32	892	0.00%	0.00	0	0.00%	0.00	0	1.19%	71.32	2,849
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	98.68%	2,337.67	140,393	25.95%	687.16	41,269	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.47%	11.13	1,148	0.12%	3.18	328	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	24.46%	647.71	51,844	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	16,845.00	125,521	100.00%	5,072.00	120,626	100.00%	2,368.94	141,900	100.00%	2,648.03	117,039	100.00%	5,993.00	169,076
Temperature							88			429.4			65			65			270
Pressure							517.6			517.6			14.5			14.5			14.6
Average Molecular Weight							7.45			23.78			59.90			44.20			28.21
Energy																			
mSCFH							6,384.3			1,922.3			897.8			1,003.6			2,271.3
HHV							1,765			256			0			0			0
Btu/SCF							277			133			0			0			0
LHV							1,501			229			0			0			0
Btu/SCF							235			119			0			0			0



Table 3-7: Overall H&MB – Case 6 (Off-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					19			20			21			22			23		
Description					Air to Nitric Acid Unit			Fuel Gas (Hydrogen Rich gas + PSA Off-gas)			Air to CTG			Exhaust from HRSG			Flue Gas to Feedstock Drying		
Phase					Vapor			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	0.00%	0.00	0	3.11%	682.58	19,119	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	0.00%	0.00	0	65.83%	14,427.44	29,084	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	0.04%	2.94	129	3.40%	745.20	32,796	0.04%	49.07	2,160	1.14%	1,603.96	70,589	1.14%	307.33	13,526
Water		H ₂ O	18.015	0.0	1.13%	83.12	1,497	0.00%	0.00	0	1.13%	1,577.34	28,416	10.20%	14,414.44	259,680	10.20%	2,761.94	49,757
Methane		CH ₄	16.042	909.4	0.00%	0.00	0	1.97%	431.25	6,918	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.00%	0.00	0	0.01%	2.70	86	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	77.20%	5,678.83	159,084	25.49%	5,586.99	156,511	77.20%	108,240.24	3,032,186	75.63%	106,878.80	2,994,047	75.63%	20,478.94	573,686
Oxygen		O ₂	31.999	0.0	20.71%	1,523.43	48,748	0.00%	0.00	0	20.71%	29,036.99	929,149	12.25%	17,311.46	553,946	12.25%	3,317.03	106,141
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.93%	68.41	2,733	0.19%	40.85	1,632	0.93%	1,303.93	52,089	0.79%	1,110.34	44,356	0.79%	212.75	8,499
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.01%	7,356.00	212,192	100.00%	21,917.00	246,146	100.00%	140,207.57	4,044,000	100.00%	141,318.00	3,922,618	100.00%	27,077.80	751,609
Temperature							97			97			65			200			517
Pressure							14.5			498.4			14.5			15.2			14.5
Average Molecular Weight							28.85			11.23			28.84			27.76			27.76
Energy																			
mSCFH							2,787.9			8,306.5			53,138.7			53,559.5			10,262.5
HHV							0			2,022			0			0			0
Btu/SCF							0			243			0			0			0
LHV							0			1,729			0			0			0
Btu/SCF							0			208			0			0			0



Table 3-7: Overall H&MB – Case 6 (Off-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					24			25			26			27			28		
Description					Drying Exhaust			Steam to HRSG			Steam from HRSG			Raw Water			Evaporation from Cooling Towers		
Phase					Vapor			Vapor			Vapor			Liquid			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	1.03%	306.17	13,474	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	18.64%	5,556.96	100,110	100.00%	34,372.50	619,230	100.00%	11,299.30	203,560	100.00%	128,113.17	2,307,995	100.00%	105,027.18	1,892,094
Methane		CH ₄	16.042	909.4	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	68.52%	20,427.18	572,236	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Oxygen		O ₂	31.999	0.0	11.10%	3,309.13	105,888	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.71%	212.26	8,479	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	29,812.00	800,189	100.00%	34,372.50	619,230	100.00%	11,299.30	203,560	100.00%	128,113.17	2,307,995	100.00%	105,027.18	1,892,094
Temperature							200												
Pressure							14.5												
Average Molecular Weight							26.84			18.02			18.02			18.02			18.02
Energy							11,298.7												
HHV							0												
							0												
LHV							0						0						
							0			822			266						



Table 3-7: Overall H&MB – Case 6 (Off-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					29			30			31			32			33		
Description					Water to make H2, in ZLD solids and misc losses			Fuel Gas to CTG			Excess Fuel Gas to Duct Burner			Air for Pulverizer Sealing			Depressurizing Exhaust Gas		
Phase					Liquid			Vapor			Vapor			Vapor			Vapor		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide		CO	28.010	320.5	0.00%	0.00	0	3.11%	682.58	19,119	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen		H ₂	2.0159	273.8	0.00%	0.00	0	65.83%	14,427.44	29,084	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide		CO ₂	44.010	0.0	0.00%	0.00	0	3.40%	745.20	32,796	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water		H ₂ O	18.015	0.0	100.00%	23,085.99	415,901	0.00%	0.00	0	0.00%	0.00	0	1.20%	16.15	291	0.00%	0.00	0
Methane		CH ₄	16.042	909.4	0.00%	0.00	0	1.97%	431.25	6,918	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol		CH ₃ OH	32.042	766.1	0.00%	0.00	0	0.01%	2.70	86	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia		NH ₃	17.031	359.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Nitrogen		N ₂	28.013	0.0	0.00%	0.00	0	25.49%	5,586.99	156,511	0.00%	0.00	0	77.20%	1,039.11	29,109	99.90%	3,651.35	102,287
Oxygen		O ₂	31.999	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	20.70%	278.62	8,916	0.00%	0.00	0
Hydrogen Sulfide		H ₂ S	34.082	586.8	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide		COS	60.076	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon		Ar	39.948	0.0	0.00%	0.00	0	0.19%	40.85	1,632	0.00%	0.00	0	0.90%	12.11	484	0.10%	3.66	146
Urea		CH ₄ N ₂ O	60.057	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret		(H ₂ NCO) ₂ -NH	103.080	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate		(NH ₄)(NO ₃)	80.043	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur		S	32.066	n.a.	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	23,085.99	415,901	100.00%	21,917.00	246,146	0.00%	0.00	0	100.00%	1,346.00	38,800	100.00%	3,655.00	102,433
Temperature										97						65			158
Pressure										498.4						14.5			14.5
Average Molecular Weight							18.02			11.23						28.83			28.03
Energy																			
										8,306.5						510.1			1,385.2
HHV										2,022						0			0
										243						0			0
LHV										1,729						0			0
										208						0			0



Table 3-7: Overall H&MB – Case 6 (Off-Peak, 65 °F Ambient Temperature) (cont’d)

Stream ID					34			35			36			37		
Description					BFW to Process			Process Condensate Return			Ammonia to Storage			Ammonia from Storage		
Phase					Liquid			Liquid			liquid			liquid		
Component		MW lb/lbmol	Btu/SCF LHV	Btu/SCF HHV	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h	Mol %	Lbmol/h	lb/h
Carbon Monoxide CO		28.010	320.5	320.5	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen H ₂		2.0159	273.8	324.2	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbon Dioxide CO ₂		44.010	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Water H ₂ O		18.015	0.0	0.0	100.00%	63,795.90	1,149,301	100.00%	40,722.70	733,631	0.00%	0.00	0	0.00%	0.00	0
Methane CH ₄		16.042	909.4	1,010.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Methanol CH ₃ OH		32.042	766.1	866.7	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonia NH ₃		17.031	359.0	434.4	0.00%	0.00	0	0.00%	0.00	0	100.00%	10,222.00	174,086	100.00%	7,472.00	127,252
Nitrogen N ₂		28.013	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Oxygen O ₂		31.999	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Hydrogen Sulfide H ₂ S		34.082	586.8	637.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Carbonyl Sulfide COS		60.076	622.1	622.1	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Argon Ar		39.948	0.0	0.0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Urea CH ₄ N ₂ O		60.057	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Biuret (H ₂ NCO) ₂ -NH		103.080	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Ammonium Nitrate (NH ₄)(NO ₃)		80.043	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Sulfur S		32.066	n.a.	n.a	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0	0.00%	0.00	0
Totals					100.00%	63,795.90	1,149,301	100.00%	40,722.70	733,631	100.00%	10,222.00	174,086	100.00%	7,472.00	127,252
Temperature deg F																
Pressure psia																
Average Molecular Weight lb/lbmol							18.02			18.02			17.03			17.03
Energy mSCFH													3,874.1			2,831.9
HHV mm Btu/h							311			51			1,683			1,230
Btu/SCF													434			434
LHV mm Btu/h													1,391			1,017
Btu/SCF													359			359

3.5 EMISSIONS SUMMARY

The estimated maximum annual atmospheric emissions for the HECA Project have been calculated and are as shown in Table 3-8. These emission values have been presented to and discussed with the environmental agencies reviewing the project. The three agencies listed below are responsible for reviewing and ultimately approving the maximum allowable emissions for the project:

- San Joaquin Valley Air Pollution Control District (SJVAPCD)
- California Energy Commission (CEC)
- U.S. Environmental Protection Agency, Region IX (U.S. EPA)

Detailed calculations, assumptions, and compliance discussions are contained in the report entitled, *Hydrogen Energy California, Kern County, California, Updated Emissions and Modeling Report*, prepared by URS Corporation and submitted to SJVAPCD in May 2013.

A plot plan identifying the location of emissions sources can be found in Section 3.13.1.

Table 3-8: Total Annual Emissions Summary

	Operating Hrs/yr	System	NO _x	CO	VOC	SO _x	PM-10	PM-2.5
Steady State	8000	HRSO Stack, Tons/yr	97.26	71.04	13.53	16.02	51.78	51.78
	8000	Coal Drying Stack, Tons/yr	16.05	11.73	2.23	2.64	5.19	5.19
	8000	Gasification Flare, Tons/yr	0.14	0.16	0.00	0.00	0.01	0.01
	8000	SRU Flare, Tons/yr	0.08	0.10	0.00	0.00	0.00	0.00
	8000	Rectisol Flare, Tons/yr	0.08	0.10	0.00	0.00	0.00	0.00
	8336	Process Cooling Tower, Tons/yr	-	-	-	-	15.21	9.12
	8336	Power Block Cooling Tower, Tons/yr	-	-	-	-	9.31	5.59
	8336	ASU Cooling Tower, Tons/yr	-	-	-	-	0.93	0.56
	8000	Urea Plant HP Absorber, Tons/yr	-	-	-	-	-	-
	8000	Urea Plant LP Absorber, Tons/yr	-	-	-	-	-	-
	8000	Urea Pastillation Stack, Tons/yr	-	-	-	-	0.20	0.20
	8000	Nitric Acid Plant, Tons/yr	16.70	-	-	-	-	-
	8000	Ammonium Nitrate Plant, Tons/yr	-	-	-	-	0.80	0.80
	-	Solids Handling, Tons/yr	-	-	-	-	2.35	2.35
Start-Up	-	HRSO Stack, Tons/yr	0.41	3.43	0.07	0.01	0.07	0.07
	-	Coal Drying Stack, Tons/yr	0.05	0.32	0.01	0.00	0.00	0.00
	-	Gasification Flare, Tons/yr	1.74	14.71	0.04	0.05	0.16	0.16
	-	SRU Flare, Tons/yr	0.05	0.16	0.00	0.37	0.01	0.01
	-	Rectisol Flare, Tons/yr	0.67	0.79	0.01	0.30	0.03	0.03
	-	Ammonia Plant Startup Heater	0.042	0.14	0.02	0.008	0.02	0.02
	-	Urea Plant HP Absorber, Tons/yr	-	-	-	-	-	-
	-	Urea Plant LP Absorber, Tons/yr	-	-	-	-	-	-
	-	Urea Pastillation Stack, Tons/yr	-	-	-	-	0.00	0.00
	-	Nitric Acid Plant, Tons/yr	-	-	-	-	-	-
	-	Ammonium Nitrate Plant, Tons/yr	-	-	-	-	0.54	0.54
	-	HRSO Stack, Tons/yr	0.77	8.44	0.19	0.02	0.13	0.13
	-	Coal Drying Stack, Tons/yr	0.04	0.05	0.00	0.00	0.00	0.00
	-	Gasification Flare, Tons/yr	0.66	3.57	-	-	-	-
Shutdown	-	Urea Plant HP Absorber, Tons/yr	-	-	-	-	-	-
	-	Urea Plant LP Absorber, Tons/yr	-	-	-	-	-	-
	-	Urea Pastillation Stack, Tons/yr	-	-	-	-	-	-
	-	Nitric Acid Plant, Tons/yr	-	-	-	-	-	-
	-	Ammonium Nitrate Plant, Tons/yr	-	-	-	-	-	-
	-	HRSO Stack, Tons/yr	13.66	11.38	0.41	9.22	0.46	0.46
	2190	Auxiliary Boiler, Tons/yr	1.40	8.63	0.93	0.48	1.17	1.17
	52	Emergency Engines, Tons/yr	0.25	1.00	0.11	0.00	0.02	0.02
Other	504	CO ₂ Vent, Tons/yr	-	124.99	1.71	-	-	-
	336	Power Block - natural gas steady state operation, Tons/yr	5.73	4.36	1.00	0.80	2.52	2.52
	8760	Fugitive Emissions, Tons/yr	0.005	4.8	12.2	0.1	0.1	0.03
	T o t a l		155.8	269.9	32.5	30.0	91.0	80.8

Legend:

NO_x = nitrogen oxides, expressed as NO₂

CO = carbon monoxide

VOC = volatile organic compounds (essentially non-methane, non-ethane organic compounds)

SO_x = sulfur oxides, expressed as SO₂

PM = particulate matter; "10" denotes less than 10 microns in diameter; "2.5" denotes less than 2.5 microns

Notes:

1. *The values shown in this summary are the result of calculations based on preliminary supplier data and the assumptions stated in the design basis. No guarantees are expressed or implied.*
2. *Steady State emissions based on "on-peak" power generation with annual average ambient conditions.*
3. *Solids Handling emissions shows the sum of 16 separate emissions sources.*
4. *Start-up emissions based on 2 start-ups per year.*
5. *Shutdown emissions based on 2 shutdowns per year.*
6. *Auxiliary Boiler emissions based on 25% capacity factor, or 2190 operating hours per year.*
7. *Emergency Engines emissions based on 50 hr/yr normal maintenance operation per emergency generator engine and 100 hr/yr fire pump engine operation.*
8. *CO₂ Vent emissions based on 21 days per year of CO₂ venting at the maximum production rate.*
9. *Power Block emissions while operating on natural gas are based on 14 days of the CTG at 80% load.*
10. *Fugitive emissions are from non-point sources, e.g., rotating equipment seals, valve stem seals, etc., plus fugitive dust from in-plant vehicles.*

3.6 DESIGN BASIS

The Project Design Basis provides the technical criteria used in performing the Front End Engineering and Design (FEED). It consists of 3 major sub sections:

- Basic Engineering and Design Data
- Process Design Basis
- Engineering Design Criteria

3.6.1 Basic Engineering and Design Data

The Basic Engineering and Design Data (BEDD) are provided in this section.

A. Area / Unit Description

The HECA Project Area / Unit Descriptions are shown in the table that follows. Those Area / Units containing data and information provided by Technology Licensors that is protected from FOIA release by License Agreements and/or by Non-Disclosure Agreements (NDAs) have been identified in the table as *“Licensor Confidential Technology.”* Specialty Contractor and Supplier Technology are also identified.

Table 3-8: Area / Unit Description

AREA	UNIT	DESCRIPTION
000		Common
	000	Common / Overall
010		Gasification
	011	Feedstock Drying & Milling (<i>Licensors Confidential Technology</i>)
	012	Gasifier Feed System (<i>Licensors Confidential Technology</i>)
	013	Gasification Island (<i>Licensors Confidential Technology</i>)
020		Gas Treating
	021	Syngas Cooling / Scrubber
	022	Two Stage Shift / Low Temperature Gas Cooling
	023	Sour Water Treatment
	024	Mercury Removal
030		Acid Gas Removal & Refrigeration
	031	Acid Gas Removal (<i>Licensors Confidential Technology</i>)
	032	AGR Refrigeration
040	040	CO₂ Compression / Purification
050	050	Sulfur Plant
	051	Sulfur Recovery Unit (SRU) (<i>Licensors Confidential Technology</i>)
	052	Tail Gas Unit (TGU) (<i>Licensors Confidential Technology</i>)
060	060	PSA & Off-Gas Compression
070		Power Block
	071	Combustion Turbine / Steam Turbine / Generator (CT/ST/G)
	072	Heat Recovery Steam Generator (HRSG)
	073	Balance Of Power Block / BFW / Low & High Temp Flue Gas Ducting
080		Fertilizer Complex
	081	Ammonia Synthesis Unit (<i>Licensors Confidential Technology</i>)
	082	Urea Unit (<i>Licensors Confidential Technology</i>)
	083	Solid Urea Production (<i>Supplier Proprietary Technology</i>)
	084	UAN Complex (<i>Licensors Confidential Technology</i>): •Nitric Acid Unit •Ammonium Nitrate Unit •Urea Ammonium Nitrate (UAN) Unit
090		Water Treatment Plant
	091	Raw Water Treatment (<i>Specialty Contractor Confidential Technology</i>)

AREA	UNIT	DESCRIPTION
	092	Demin Water System Treatment (<i>Specialty Contractor Confidential Technology</i>)
	093	Wastewater Treatment (<i>Specialty Contractor Confidential Technology</i>)
100		OSBL (Utilities & Offsites)
	000	Miscellaneous Roads and Paving
	100	OSBL Common
	101	Cooling Water System - Process
	102	Cooling Water System - Power Block
	103	Recovered Condensate System
	104	Auxiliary Boiler
	105	Emergency Diesel Generators
	106	Plant & Instrument Air Systems
	107	Flare Systems: •Gasification Flare •Rectisol Flare •SRU Flare
	109	Natural Gas Distribution System
	110	Utility Water Distribution System
	111	Potable Water Distribution System
	112	Sanitary Sewer / Sewage Leach Field
	113	Storm Water System / Storm Water Retention Ponds
	114	Solids Handling Drainage System
	115	Oily Water Sewer
	120	OSBL Interconnecting (Including misc. utility distributions)
	121	Rail Road Spur & Loop
	123	Rail & Truck Feedstock Unloading, Handling & Storage
	124	Gasification Solids Storage, Handling & Rail / Truck Loading
	125	Sulfur Liquid Storage, Handling & Rail / Truck Loading
	126	Urea Pastilles Solids Storage, Handling & Rail / Truck Loading
	127	Ammonia and Urea Ammonium Nitrate (UAN) Solution Liquid Storage, Handling & Rail / Truck Loading
	128	Firewater / Fire Protection System
	130	DCS

AREA	UNIT	DESCRIPTION
	131	Communications: •Security •Telephone •CCTV •Fiber Optic and Network (LAN) •Fire and Gas Detection •Radio
	132	Electrical: •High Voltage Switchyard (On-Site) •Power Distribution •Electrical Substations (Power Distribution Centers) •UPS
	133	Buildings (Outside Unit Battery Limits): •Control Room, Administration, and Laboratory Building •Maintenance Shop and Warehouse •Main Security Guardhouse •Emergency Response and Medical Center
150		Interfaces to Site
	151	HV Transmission Line
	152	Access Road and Existing Drainage Ditches Improvements (Outside of Plant)
	153	Natural Gas Pipeline
	154	CO ₂ Pipeline
	155	Raw Water and Potable Water Pipelines
	156	Air Separation Unit

B. Design Philosophy

i) General

The technology and equipment selection minimizes risk where possible, using standard and proven technology and equipment presently operating within industry at equivalent capacities and design criteria, wherever available.

Design life of the plant is 25 years. However, design and technology selection decisions are based on lifecycle cost analysis, i.e., operational costs and availability impacts, as well as capital costs. The plant design is evaluated on a 20 year life cycle cost analysis including utilities and operating and maintenance costs, as well as capital costs.

Since the project is based on a zero liquid discharge (ZLD) process, the waste effluent stream from any given unit is minimized. Disposition of any intermediate flash stream within any given unit is part of the design.

The minimum metal design temperature is +20 °F.

Any subsystems required for the compliance with the application of Lowest Available Emission Rate (LAER)/Best Available Control Technology (BACT) is evaluated and incorporated into the design as applicable.

ii) Steam

Electric motor drivers are used throughout so that the steam produced can be integrated into the power cycle to maximize power output.

iii) Flare

All relief and blowdown releases are routed to flare systems (i.e. Gasification flare, Rectisol flare, SRU flare) except for steam and non-hazardous gases.

iv) Air Cooled versus Water Cooled Heat Exchangers

Break point between the water cooled versus air cooled heat exchangers is 140 °F except the compressor intercoolers and aftercoolers which have hot-side temperatures >140 °F but are water cooled.

v) Steam Condensate

Steam condensate is recovered and returned to the condensate collection header.

vi) Control System

The control system philosophy includes monitoring and control of equipment and facilities based on implementation of distributed control system (DCS), regulatory control, shutdown, process, laboratory and management information systems. Operation of units is from a central control room with separate operating consoles. Designs requiring Operator participation or intervention from within a unit (i.e. field operations) are minimized where possible.

vii) Codes and Standards

The facilities are designed to the governmental & industry standards from the following organizations when appropriate for and applicable to this project:

1. Government Regulations

- California Energy Commission/Warren-Alquist Act , California Code of Regulations, Title 20, Public Utilities and Energy
- OSHA - Occupational Safety and Health Act
- 29 CFR 1910 Occupational Safety and Health Standards
- 29 CFR 1926 Safety and Health Regulations for Construction
- 40 CFR 60.18 Protection of Environment Part 60-Standards of Performance
- EPA - Environmental Protection Agency
- EPA Standard of Performance for New Stationary Sources
- California Code of Regulations, Title 8, Industrial Relations
- Cal OSHA - California Division of Occupational Safety and Health
- SJVAPCD - San Joaquin Valley Air Pollution Control District
- Other Applicable State, County and Local Codes and Regulations

2. Mechanical

- AGMA - American Gear Manufacturer's Association
- AMCA - Air Moving and Control Association
- ABMA - American Boiler Manufacturer's Association

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- ANSI - American National Standards Institute, Applicable Codes and Standards
 - ASME - American Society of Mechanical Engineers - Boiler and Pressure Vessel Code:
 - Section I - Power Boilers
 - Section II - Materials Specification
 - Section V - Nondestructive Examination
 - Section VIII - Unfired Pressure Vessels
 - Section IX - Welding and Brazing Qualifications
 - ASME - American Society of Mechanical Engineers, B31.1 Power Piping
 - ASME - American Society of Mechanical Engineers, B31.3 Process Piping
 - PTC - Performance Test Codes - Applicable Test Codes
 - STS-1 - Steel Stacks (wind loads per ASCE 7)
 - ASNT - American Society for Nondestructive Testing
 - ASTM - American Society for Testing and Materials
 - AWS - American Welding Society
 - AWWA - American Water Works Association
 - CGA - Compressed Gas Association
 - CTI - Cooling Tower Institute
 - EJMA - Expansion Joint Manufacturing Association
 - HEI - Heat Exchanger Institute
 - NBIC - National Boiler and Inspection Code
 - NFPA - National Fire Protection Association, National Fire Codes and Standards, including all requirements of
 - NFPA 850, Recommended Practice for Fire Protection for Electric Generating Plants
 - TEMA - Tubular Exchanger Manufacturer Association
 - HI - Hydraulic Institute Standards
 - SSPC - Steel Structures Painting Council

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- CEMA - Conveying Equipment Manufacturers Association
 - HMI - Hoists Manufacturers Institute
 - ASHRAE - American Society of Heating, Refrigeration, and Air Conditioning Engineers
 - CMAA - Crane Manufacturers Association of America
 - ASME B30.2 - Overhead and Gantry Cranes
 - API - American Petroleum Institute API-650 Latest Addendum
 - API – American Petroleum Institute API-537
 - API-600 Shell and Tube Heat Exchangers
 - API-661 Air Cooled Heat Exchangers.

3. Electrical

- ASTM - American Society for Testing and Materials
- ANSI - American National Standards Institute
- FAA - Federal Aviation Administration (Standards for Marking and Obstruction Lighting for Aerial Navigation)
- FM - Factory Mutual
- ICEA - Insulated Cable Engineers Association
- AEIC - Association of Edison Illuminating Companies
- IEEE - Institute of Electrical and Electronics Engineers
- LPC - Lightning Protection Code (NFPA 780)
- NEC - National Electrical Code
- NEMA - National Electrical Manufacturers Association
- NESC - National Electrical Safety Code (Only for interconnection switchyard work)
- NFPA - National Fire Protection Association, National Fire Codes and Standards, including all requirements of
 - NFPA 497, Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas
- IESNA - Illuminating Engineering Society of North America
- ISA - International Society of Automation
- UL - Underwriters Laboratories
- California Electrical Code
- Kern County Electrical Code
- OSHA - Occupational Safety and Health Act (OSHA)
- API - American Petroleum Institute
- Cal-OSHA California Occupational Safety and Health

4. Civil/Structural/Architectural (CSA)

- SDI - Steel Deck Institute Standards
- SJI - Steel Joist Institute Standards
- AWWA - American Water Works Association
- PFI - Pipe Fabrication Institute
- California Code of Regulations, Title 24 (CCR), or California Building Code (CBC)
- MSS - Manufacturers Standardization Society
- NACE - National Association Corrosion Engineers
- IMC - International Mechanical Code
- NSPC - National Standard Plumbing Code
- AISC - American Institute of Steel Construction
- AISI - American Iron and Steel Institute (Specification for Design of Cold-Formed Steel Structural Members, Parts 1 and 2)
- AWS - American Welding Society (Structural Welding Code, AWS D1.1)
- ACI - American Concrete Institute (Building Code Requirements for Reinforced Concrete, ACI 318, and Environmental Engineering Concrete Structures, ACI 350R)
- MBMA - Metal Building Manufacturers Association
- NFPA 101 - Life Safety Code
- ASCE - Minimum Design Loads for Building and other Structures (ASCE 7)
- AWS - American Welding Society Welding of Reinforcing Steel (D1.4)
- SSPC - Steel Structures Painting Council

5. Other

The Gasification Island, Power Block equipment (CT/ST/G), and any other equipment sourced from Japan are designed to the following standards:

- Japanese Industrial Standards (JIS)
- International Electrotechnical Commission (IEC)
- Japanese Electrotechnical Committee Standards (JEC)
- Japanese Electrical Manufacturers' Association Standards (JEMA)

viii) Units of Measurement

Project design calculations and data are in the English / US system of measurement as specified in the table below.

Table 3-9: Units of Measurement

Dimension	English System Unit	Abbreviation / Acronym
Density	Pound per cubic foot	lb / ft ³
Viscosity	Centipoise	cP
Energy, heat, work, internal energy, enthalpy	British Thermal Unit	Btu
Force	Pounds Force	lb _f
Length	Foot Inch	ft in
Mass	Pounds Short Tons	lb sT
Power	Watts (power generation) Watts (electric heaters) Horsepower (for electric motors)	W W hp
Pressure	Pounds Force per Square Inch Absolute Pounds Force per Square Inch Gauge	psia psig
Temperature	Degrees Fahrenheit	°F
Velocity	Feet per Second Miles per Hour	ft / s mph
Volume	Cubic Feet Barrels Gallons	ft ³ BBL Gal
Conductivity	MicroSiemens per Centimeter	μS/cm
Resistivity	Megaohms per centimeter	megohm/cm
Standard Condition	60 °F / 14.7 psia	

C. Site Data

Table 3-10: Site, Soil, Seismic, Structural, and Meteorological Conditions

Location	Kern County, California, USA 21 miles west of downtown Bakersfield and 3 miles northwest of the community of Tupman	
Site Condition	Greenfield Site	
Ambient Air Conditions (Note 1)	Dry-Bulb Temperature	Relative Humidity
Summer Design	97 °F	20%
Winter Design	39 °F	82%
Annual Average	65 °F	55%
Extreme High	115 °F	15%
Extreme Low	20 °F	85%
Elevation		
Elevation	288.5 ft above mean sea level [undeveloped area elevation varies from 285 to 288 feet]	
Barometric Pressure	14.54 psia	
Wind		
Average Wind Speed	7.61 mph	
Basic Wind Speed (3-second gusts)	85 mph as per CBC 2010	
Coordinates	35.3393 Latitude and -119.3938 Longitude	
Rainfall		
Average precipitation per year	6.5 inches (average 1981 – 2010)	
Intermediate Storm Design Discharge (ISDD) 10 year 5 day depth of rainfall	2.62 inches per NOAA Atlas 14, Vol.6, Ver.2.0 as directed by Kern County Engineering Development Standards (Division Four)	
Flood Hazard	The project site is located outside the limits of the 100-year flood boundary as identified on the Federal Emergency Management Agency (FEMA) Flood Insurance Rate Map (FIRM) for Kern County, California, Map Number 06029C2225E effective date September 26, 2008.	
Seismic and Structural Requirements		
Reference Standards:	The Project Site is located in a high seismicity area and the mapped maximum credible accelerations and design response spectrum will be determined from § 1613 of CBC 2010.	
Seismic Design Category	D	
Seismic Site Class	D	
Importance Factor	1.25	
Design Spectral Response Acceleration at Short Period	$S_{DS} = 0.779g$	
Design Spectral Response Acceleration at One-Second Period	$S_{D1} = 0.498g$	

Note: 1. Design ambient condition for air coolers is 97 °F @ 20% RH.

D. Fuel Gas, Oxygen, Nitrogen, and Water and Steam Quality

The properties of Fuel Gas, Oxygen, Nitrogen, Raw Brackish Water, Demineralized Water, Process & Power Block Cooling Tower Makeup Water, Process & Power Block Circulating Cooling Water, Service / Utility Water, BFW, and Steam are listed in the tables below.

i) Fuel Gas

Multiple natural gas pipelines systems are potentially suited to supply natural gas to the Project, including Pacific Gas and Electric (PG&E), Southern California Gas Company, Mojave/Kern River Gas Transmission Company, Occidental, and Chevron. The resultant laterals from each of these pipeline trunks range from approximately 5 to 17 miles. The service provider would have ultimately been selected after considering numerous factors, including, but not limited to: route viability, environmental impacts, land value, delivery pressures (normal and minimum), and commercial terms.

Table 3-11: Fuel Gas Quality

NG Supply to Site Boundary (Fence Line)	(Pipeline) By Others
Natural Gas Btu Content, HHV	1,022 Btu/scf
Natural Gas Specific Gravity	0.58
Natural Gas Composition (Mol. %):	
Methane	96.07
Ethane	1.9
Propane	0.3
n-Butane	0.05
Iso-Butane	0.05
n-Pentane	0.01
Iso-Pentane	0.02
Hexane +	0.03
Nitrogen	0.46
Carbon Dioxide	1.08
Sulfur	<0.75 grain/100 scf
Natural Gas Pressure	>350 psig

ii) Oxygen and Nitrogen

The ASU design conditions for the product O₂ and product N₂ streams are below.

Table 3-12: Oxygen and Nitrogen ASU Performance Specification

Product	Avg. Flow Rate	Design Flow Rate	Units	Purity	Pressure (psig)	Temperature °F
HP O ₂ to Gasification	3,471 ¹	3,711	Contained sTPD	99.5 mol% O ₂	838	Compressor Discharge Temperature
LP O ₂ to Sulfur Plant	57	71	Contained sTPD	99.5 mol% O ₂	75	70
Total O ₂ Production	3,528	3,782	Contained sTPD	99.5 mol% O ₂	–	–
HP N ₂ as Carrier Gas for Dry Coal Feed to Gasifier	3,306	3,656	Total sTPD	O ₂ < 0.1 mol%	907	158
Diluent N ₂ to CT (On-Peak)	7,694	8,079 ⁽³⁾	Total sTPD	99.0 mol% O ₂ < 0.1 mol%	512 ²	Compressor Discharge Temperature
Diluent N ₂ to CT (Off-Peak)	5,781	– ⁽³⁾	Total sTPD	99.0 mol% O ₂ < 0.1 mol%	512	Compressor Discharge Temperature
High Purity MP N ₂ to Ammonia Synthesis Plant (On-Peak) ⁴	1,034	1,085 ⁵	Total sTPD	99.99 mol%, O ₂ < 5 ppmv, Ar < 100 ppmv	490 ⁶	105
High Purity MP N ₂ to Ammonia Synthesis Plant (Off-Peak) ⁷	1,723	1,809 ⁸	Total sTPD	99.99 mol%, O ₂ < 5 ppmv, Ar < 100 ppmv	490	105
LP N ₂ for Continuous Purging and Plant Blanketing	50	550 ⁹	Total sTPD	99.5 mol% N ₂ O ₂ < 5 ppmv,	135	Ambient
Instrument & Plant Air	1,650	4000 ¹⁰	SCFM	-40 °F Dew Point	125	120 maximum

Notes:

- ¹ Based on normal operating case (NOC) of 100% load with 75%/25% HHV coal/pet coke split.
- ² The value shown is the interface pressure at the ASU battery limit. The diluent N₂ pressure is controlled by the ASU supplier at the combustion turbine (CT) battery limit.
- ³ Design flow is set by on-peak operation.
- ⁴ The basis of design is for 16 hours of daily peak operation and 8 hours of daily off-peak operation.
- ⁵ Includes 5% margin over average flow.
- ⁶ The value shown is the interface pressure at the ASU battery limit. The HP N₂ pressure is controlled by the ASU supplier at the Ammonia Synthesis Plant battery limit. 20 psi pressure drop is estimated at design flow due to piping and heat exchangers between the ASU and Ammonia Synthesis Plant battery limits.
- ⁷ The basis of design is for 16 hours of daily peak operation and 8 hours of daily off-peak operation.
- ⁸ Includes 5% margin over average flow.
- ⁹ Design flow represents allowance for continuous users (50 TPD) plus the single largest intermittent user (488 TPD for Shift heat-up). Shift heat-up occurs when HP O₂ to gasification demand is zero while the plant is coming out of a total plant outage.
- ¹⁰ Basis: The 4000 SCFM includes instrument and plant air requirements for the entire facility. The ASU includes an Air Dryer, which will dry air to a dew point of -50 °F.

iii) Raw Water

Table 3-13: Estimated Water Quality for Raw Water from BVWSD

Parameter	Units	Projected Average	Projected Maximum
Temperature	°F	65	65
pH	--	7.25	7.25
Total Dissolved Solids (TDS)	mg/L ^b	2,000	4,000
Total Suspended Solids (TSS)	mg/L	5	5
Total Alkalinity (as CaCO ₃)	mg/L	238	328
Hardness	mg/L	897	1,561
Calcium	mg/L	300	500
Magnesium	mg/L	35	75
Sodium	mg/L	278	726
Potassium	mg/L	2	3
Strontium	mg/L	3.0	3.0
Carbonate	mg/L	20	20
Bicarbonate	mg/L	250	400
Chloride	mg/L	381	1,237
Sulfate	mg/L	700	1,000
Fluoride	mg/L	0.4	1
Nitrate (as NO ₃)	mg/L	0.2	0.2
Silica	mg/L	30	35
Boron	mg/L	2.5	5
Barium	mg/L	0.035	0.045
Iron	mg/L	2.0	2.0
Selenium	mg/L	0.025	0.025
Manganese	mg/L	1.5	2.5
Copper	mg/L	0.01	0.01
Zinc	mg/L	0.02	0.02
Arsenic	mg/L	0.025	0.025

Notes:

- Brackish groundwater raw water supply.
- mg/L - milligrams per liter Source: Values for the Buena Vista Water Storage District (BVWSD) source water represent a composite of historical laboratory test results on elevated TDS wells provided by BVWSD. Average of the water sample data provided by BVWSD.

iv) Demineralized Water

Table 3-14: Demineralized Water Quality

Case Description	Max Power Production at High Avg Ambient Temperature (97 °F)	Min Power Production at Low Avg Ambient Temperature (39 °F)
Temp (°F)	80	70
pH	5.31	5.53
TDS (mg/L)	0.00	0.00
Calcium (mg/L)	0	0
Magnesium (mg/L)	0	0
Sodium (mg/L)	0.00	0.00
Potassium (mg/L)	0	0.0
Strontium (mg/L)	0	0.0
Carbonate (mg/L)	0	0.0
Bicarbonate (mg/L)	0	0
Chloride (mg/L)	0.00	0.00
Sulfate (mg/L)	0.00	0.00
Fluoride (mg/L)	0	0
Nitrate (mg/L)	0	0
Silica (mg/L)	0	0
Boron (mg/L)	0.014	0.004
Barium (mg/L)	0	0
Iron (mg/L)	0	0
Selenium (mg/L)	0	0
Manganese (mg/L)	0	0
Copper (mg/L)	0	0
Zinc (mg/L)	0	0
Arsenic (mg/L)	0	0
Alkalinity (mg/L As CaCO ₃)	0	0

v) Cooling Tower Makeup Water

Table 3-15: Process and Power Block Cooling Tower Makeup Water Quality

Case Description	Max Power Production at High Avg Ambient Temperature (97 °F)	Min Power Production at Low Avg Ambient Temperature (39 °F)
Temp (°F)	68	67
pH	8.3	8.32
TDS (mg/L)	3,697	1,825
Calcium (mg/L)	2.8	1.3
Magnesium (mg/L)	47.4	31.2
Sodium (mg/L)	1,239	585
Potassium (mg/L)	3.8	3.2
Strontium (mg/L)	0.5	0.2
Carbonate (mg/L)	1	1.8
Bicarbonate (mg/L)	46.8	91.6
Chloride (mg/L)	1,192	355
Sulfate (mg/L)	1,036	709
Fluoride (mg/L)	0.968	0.377
Nitrate (mg/L)	0.2	0.193
Silica (mg/L)	17.9	15
Boron (mg/L)	5.527	2.681
Barium (mg/L)	0.01	0.009
Iron (mg/L)	0	0
Selenium (mg/L)	0.024	0.024
Manganese (mg/L)	0.063	0.015
Copper (mg/L)	0.01	0.009
Zinc (mg/L)	0.019	0.019
Arsenic (mg/L)	0.025	0.024
Alkalinity (mg/L As CaCO ₃)	53.8	101.5

vi) Cooling Water Circulation

Table 3-16: Process and Power Block Circulating Cooling Water Quality

Case Description	Max Power Production at High Avg Ambient Temperature (97 °F)	Min Power Production at Low Avg Ambient Temperature (39 °F)
Temp (°F)	80	80
pH	8.28	8.27
TDS (mg/L)	8,928	8,959
Calcium (mg/L)	17.2	37.7
Magnesium (mg/L)	113.9	151.7
Sodium (mg/L)	2,987	2,860
Potassium (mg/L)	9.3	15.5
Strontium (mg/L)	1.2	1.1
Carbonate (mg/L)	2.4	8.7
Bicarbonate (mg/L)	114.6	447.5
Chloride (mg/L)	2,875	1,741
Sulfate (mg/L)	2,493	3,455
Fluoride (mg/L)	2.339	1.842
Nitrate (mg/L)	0.488	0.952
Silica (mg/L)	43.1	73
Boron (mg/L)	13.9	13.6
Barium (mg/L)	0.024	0.046
Iron (mg/L)	0	0
Selenium (mg/L)	0.059	0.116
Manganese (mg/L)	0.151	0.072
Copper (mg/L)	0.024	0.046
Zinc (mg/L)	0.047	0.092
Arsenic (mg/L)	0.06	0.119
Alkalinity (mg/L as CaCO ₃)	142.2	526.9

vii) Service / Utility Water

Table 3-17: Service / Utility Water Quality

Case Description	Max Power Production at High Avg Ambient Temperature (97 °F)	Min Power Production at Low Avg Ambient Temperature (39 °F)
Temp (°F)	85	77
pH	7.8	7.8
TDS (mg/L)	115.6	85.3
Calcium (mg/L)	35	35
Magnesium (mg/L)	0	0.0
Sodium (mg/L)	22.9	12.8
Potassium (mg/L)	0.1	0.0
Strontium (mg/L)	0	0.0
Carbonate (mg/L)	0	0.0
Bicarbonate (mg/L)	6.4	1.9
Chloride (mg/L)	28.2	17.0
Sulfate (mg/L)	4.30	1.70
Fluoride (mg/L)	0.029	0.007
Nitrate (mg/L)	0.023	0.013
Silica (mg/L)	0.1	0
Boron (mg/L)	1.985	0.585
Barium (mg/L)	0	0
Iron (mg/L)	0	0
Selenium (mg/L)	0.001	0.001
Manganese (mg/L)	0	0
Copper (mg/L)	0	0
Zinc (mg/L)	0.001	0
Arsenic (mg/L)	0.002	0.002
Alkalinity (mg/L as CaCO ₃)	42.4	37.1

viii) Boiler Feed Water

Table 3-18: Boiler Feed Water Quality

Cation Conductivity, $\mu\text{S}/\text{cm}$	< 0.3
pH	9.0-9.6
Copper, ppb	< 2
Iron, ppb	< 5
Sodium, ppb	< 5
Silica, ppb	< 10
Chlorides, ppb	< 5
Dissolved Oxygen, ppb	< 10

ix) Steam

Table 3-19: Steam Purity

Steam Purity Requirements for Steam Entering the STG					
Control Parameters	Parameter	Notes	Normal Operations	Limiting	
				Two Weeks	24 Hours*
	Cation Conductivity ($\mu\text{S}/\text{cm}$)	b,c	< 0.3	0.3 - 0.5	0.5 - 1.0
	Dissolved Oxygen (ppb)	b,c	< 10	10 - 30	30 - 100
	Sodium (ppb)	b,c	< 5	5 - 10	10 - 20
	Chlorides (ppb)	b,c	< 5	5 - 10	10 - 20
	Silica (ppb)	b	< 10	10 - 20	20 - 50
	Copper (ppb)	a	< 5		
	Iron (ppb)	a	< 20		
	Na/PO ₄ Molar Ratio	a,e	~3		
	Sulfites and Sulfates	d			

Notes:

- Typical value, should be analyzed at least once a week.
- Used for chemistry control by continuous direct analyzed of condensed inlet steam or as recalculated from steam generator water and mechanical plus vaporous carryover.
- Continuous analysis recommended
- Less than minimum detectable, should be analyzed at least once a week.
- For units with phosphate water treatment.

E. Utility Conditions

Table 3-20: Available Utilities at Unit Battery Limit

UTILITY SERVICE	Notes	OPERATING CONDITIONS AT SOURCE BATTERY LIMIT		OPERATING CONDITIONS AT USER BATTERY LIMIT		MECHANICAL DESIGN CONDITIONS		Flange Rating#
		psig	°F	psig	°F	psig	°F	
Auxiliary Steam								
High Pressure (HP) Steam	1	725	750	700	750	800	800	600#
Medium Pressure (MP) Steam		385	445	360	439	435	500	300#
Low Pressure (LP) Steam		60	308	50	298	100	400	150#
Steam Condensate								
Medium Pressure (MP) Condensate	9	60	298	50	287	100	400	150#
Low Pressure (LLP) Condensate	9, 10	30	212	5	212	50	300	150#
Pumped Condensate	5, 9	150	212	100	212	240	265	150 #
Water								
Service/ Utility Water	7, 8,9	100	95	75	90	150	150	150 #
Demineralized Water	9	120	90	75	70	200	150	150#
Firewater	9	125	100	105	100	175	150	150#
Potable Water	2 , 6, 9	75	60	40	60	250	125	150#
Boiler Feed Water								
HP BFW		1275	253	1240	250	1610	305	900#
LP BFW		220	253	190	250	350	305	300#
Process Block Cooling Water								
Process CW Supply	9	80	80	65	80	150	150	150#
Process CW Return	3, 9	40	115	30	115	150	150	150#
Power Block Cooling Water								
Power Block CW Supply	9	48	80	38	80	75	150	150#
Power Block CW Return	3, 9	38	100	28	100	75	150	150#
Plant & Instrument Air								
Plant Air		125	120	100	120	175	170	150#
Instrument Air		125	120	100	120	175	170	150#
Natural Gas								
HHP Natural Gas	11	815	220	805	200	1020	250	600#
HP Natural Gas	11	735	100	725	95	930	150	300#
IP Natural Gas	11	560	100	550	95	620	150	300#
LP Natural Gas	11	75	65	60	65	125	150	150#
Nitrogen								
LP Purge Nitrogen		135	65	115	65	200	100	150#

Notes:

1. The HP Steam operating temp. varies from 509 °F to 750 °F based on source conditions.

2. Potable water mechanical design pressure per suppliers (BVWSD and West Kern Water District).
3. Cooling water return temperature to be optimized for each user up to a maximum of 115 °F.
4. Nitrogen Purge operating and mechanical design conditions per the ASU supplier.
5. The pumped condensate is routed via the Low Temperature Economizer of the HRSG to the deaerator located in the Power Block.
6. Maximum potable water temperature to eye wash stations and safety showers is 95 °F. Anti-scalding valves are provided to limit the temperature rise from solar radiation.
7. A booster pump is required to provide utility water to the Truck Wash Station in the Gasification Unit (@ 180 ft elevation).
8. Service water is used for Evaporator Makeup Water and Air Separation Unit Cooling Tower Makeup Water.
9. For liquid services, all pressures are referenced at grade level.
10. Recovered Low Low Pressure Condensate is flashed at atmospheric pressure. The recovered header pressure varies from 0 to 30 psig.
11. The natural gas Operating and Mechanical design conditions (Pressure & Temperature) are based on preliminary analysis of potential service provider data.

F. Electrical System Data

Electrical System requirements are listed in the tables below:

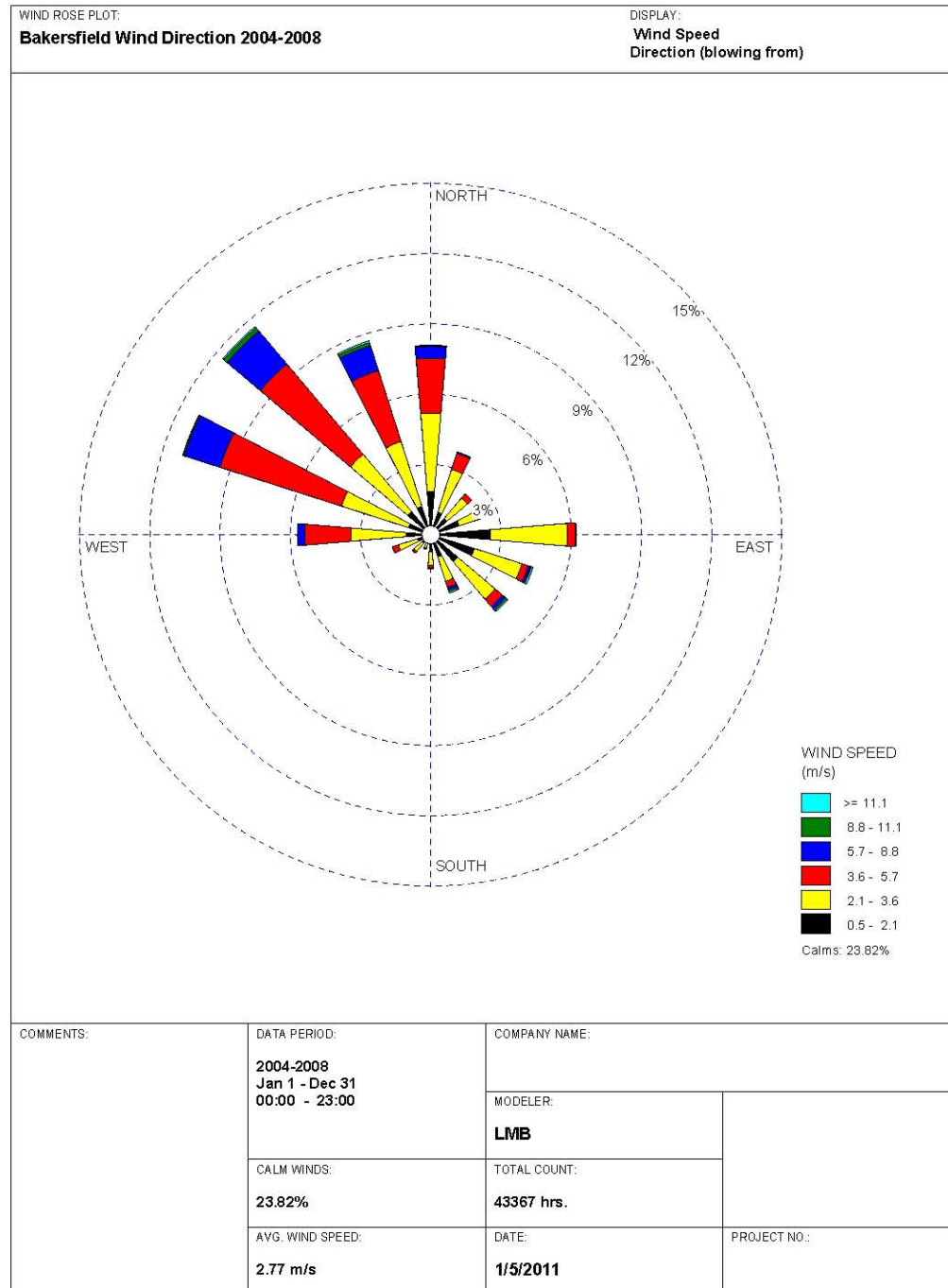
Table 3-21: Plant Voltage Table

Service	Motor or Generator Rated Voltage	System Voltage
Utility interface operating voltage	—	230 kV
Utility interface operating voltage	—	230 kV
Generator voltage	21 kV	21 kV
Large Sync and Induction Motors 5,000 HP and above	13,200 V	13,800 V
Motors 300 hp and less than 5,000 hp	4,000 V	4,160 V
LV motors from 3/4 HP to 250 HP (MOVs rated ½ HP and above).	460 V	480 V
Standby generator voltage	4.16 kV	4.16 kV
Street or area flood lighting	—	480 V
Lighting, receptacles, space heaters, heat tracing	—	208/120 V
Motors 0.5 hp and below (1-phase)	115 V	120 V
UPS power (1-phase)	—	120 V
Protection system, LV & MV switchgear controls, UPS input power	—	125 VDC
DC Emergency lube and seal oil pump motors	—	125 VDC
DCS instrumentation and controls	—	24 VDC

Table 3-22: Plant Frequency Data

Frequency Range (Continuous)	60 Hz

G. Wind Rose



3.6.2 Process Design Basis

The Process Design Basis is provided in this section. “Late Changes” that were identified after FEED engineering cut-off are not incorporated. These design changes were to be addressed in a subsequent phase of engineering. The Process Design Basis provides the scope of facilities, feedstock properties, product definitions, and criteria for atmospheric emissions, effluents and noise.

A. Plant / Unit Definition

Scope of Facilities

Feedstock Storage	Single storage barn includes: 30-day storage for coal. 30-day storage for coke. Storage for coal and coke are segregated.
Coal Rail Receiving	1 x 100% based on delivery by unit train. Single unit includes: Rapid discharge dumper. Unloading building. As received sampling system. Conveying system to storage building.
Petroleum Coke (Coke) and Coal Truck Receiving	1 x 100% based on delivery by truck. Single unit includes: Two parallel bottom-dump truck unloading stations. Unloading building. As received sampling system. Conveying system to storage barn. Only one type of feedstock can be delivered at a given time.
Coal / Coke Reclaiming, Crushing and Handling	2 x 100% Each unit includes: Portal reclaimer. Transfer conveyor in storage building. 2 x 100% reclaim conveyors to the crusher building. 2 x 100% crushing systems. 2 x 100% conveying system to coal drying system silos.

Air Separation Unit (ASU)

1 x 100%

Single unit includes:

Equipment configuration determined by the supplier in order to meet Owner reliability and availability requirements.

ASU is water cooled.

Liquid Oxygen (LOX) Storage – 12 hours at total ASU design rate, uninterruptible.

Liquid Nitrogen (LIN) Storage – 2.5 hours at total ASU design rate, uninterruptible.

Unit produces the following:

High pressure, high purity oxygen (99.5 mole % O₂) for use in the gasifier.

Low pressure, high purity oxygen (99.5 mole % O₂) for use in SRU.

High pressure, high purity nitrogen (99.9 mole % N₂, <0.1 mol% O₂) for gasification.

High pressure, high purity nitrogen (99.9 mole % N₂, 5 ppmv O₂) for ammonia synthesis.

High pressure nitrogen (99.9 mole % N₂, <0.1 mol% O₂) for combustion turbine diluent.

Low pressure, high purity nitrogen (99.9 mole % N₂, 5 ppmv O₂) for purging

ASU is a third-party design, build, own, and operate (DBOO) facility.

Gasification Island

1 x 100%

Oxygen-Blown Gasification Technology.

Licensors is Mitsubishi Heavy Industries.

Single unit includes:

Feedstock Drying / Grinding / Feeding System

Gasifier

Syngas Cooler

Gasification Solids Removal & Dewatering System

Char Recovery and Feed System

Mercury controls included on coal drying exhaust to atmosphere sufficient to meet Federal MATS regulations.

Gasification Solids Storage and Transport	1 x 100% rail and truck loading. 7-day storage on storage pad. Single unit includes: Conveyor from Gasification Solids Dewatering interface to storage. Final Dewatering & Storage Manual reclaim system. Bucket Elevator. Conveying system to rail / truck load-out facility. Truck load-out system. Rail load-out system.
Syngas Scrubbing	1 x 100%
Sour Shift	2 x 50% Unit includes two parallel trains of two reactors in series. Only the reactors are 2 trains, remainder of unit is single train.
Low Temperature Gas Cooling (LTGC)	1 x 100%
Mercury (Hg) Removal	1 x 100% Mercury controls included on coal drying exhaust to atmosphere. 1 x 100% Activated Alumina Beds for 99% mercury removal from syngas.
Sour Water Stripper	1 x 100% Treats Syngas Scrubber bottoms.
Ammonia Stripper	1 x 100% Treats LTGC condensate.
Sulfur Recovery Unit (SRU) Includes Sulfur Degassing	1 x 100% Product is molten degassed sulfur.
Tail Gas Unit (TGU)	1 x 100% Prepares SRU Tail Gas For Compression
SRU Tail Gas Compression	2 x 100% Hydrogenated SRU tail gas recycled to Sour Shift unit.

H ₂ S Scrubber	1 x 100% Removes H ₂ S from acid gas before flaring. Startup/standby system
Tail Gas Thermal Oxidizer	1 x 100% Startup/standby system
Sulfur Storage and Transport	1 x 100% rail loading. 1 x 100% truck loading. 7-day storage in tank.
Acid Gas Removal (AGR) and Refrigeration	1 x 100% Rectisol [®] process for acid gas removal (CO ₂ and H ₂ S) from the syngas.
Pressure Swing Adsorption (PSA) and Off-gas Compression	1 x 100% Includes two units in series. Off-gas from PSA #1 is compressed and sent to PSA #2 for increased hydrogen recovery. Off-gas from PSA #2 is compressed and blended with clean syngas for use as fuel in the power block.
Ammonia (NH ₃) Synthesis Unit	1 x 100% Product is 99.9 wt. % NH ₃ (anhydrous).
Ammonia Storage	2 x 50% 7-days total storage in double-wall, double-integrity atmospheric storage tanks. Storage is sufficient to allow constant production rate of urea pastilles and UAN solution during daily cycling as well as to support cold startup of urea synthesis plants.
Ammonia Loading Rack	1 x 100% truck loading. 1 x 100% rail loading.
CO ₂ Purification	1 x 100% Removes sulfur and methanol from the CO ₂ product recovered from AGR unit prior to urea synthesis.
Purified CO ₂ Compression	1 x 100% purified CO ₂ compressor. Compressor discharge at 445 psia. CO ₂ must be compressed before use in the urea synthesis unit.

Urea Unit	1 x 100% Produces urea melt with $\leq 0.3\%$ water for solid urea pastille production. Produces 80% aqueous urea solution for UAN production.
Urea Solution Storage (for UAN Production)	1 x 100%
Nitric Acid (HNO_3) Synthesis Unit	1 x 100%
Nitric Acid Storage	1 x 100% 3-day storage
Ammonium Nitrate (AN) Unit	1 x 100%
Ammonium Nitrate Storage	1 x 100%
Urea Ammonium Nitrate (UAN) Unit	1 x 100% Product is UAN-32.
Urea Ammonium Nitrate (UAN) Storage and Transport	Three tanks totaling 45 days of storage 1 x 100% rail loading. 1 x 100% truck loading.
Urea Pastillation	11 x 10% Rotoform urea pastillation technology.
Urea Handling, Storage and Loading System	Four domes totaling 45 days of storage 1 x 100% rail loading. 1 x 100% truck loading. Single handling unit includes: Conveyors from urea pastillation unit to the storage domes. Manual reclaim system. Conveying system from storage dome to rail / truck load- out building. Single rail / truck loading building includes: Truck load-out system. Rail load-out system.
CO ₂ Compression (for EOR)	1 x 100% Compressor discharge at 2,570 psia. Product used for Enhanced Oil Recovery (EOR).

Combustion Turbine	1 x 100% Mitsubishi Heavy Industries M501GAC combustion turbine. Includes auxiliaries such as inlet evaporative cooling. Turbine is capable of firing high hydrogen shifted syngas as well as natural gas for start-up / transition to syngas and up to two weeks per year of natural-gas-only operation. Nominal output of 275 MW at 97°F when operating on shifted syngas.
Heat Recovery Steam Generator (HRSG)	1 x 100% Unit includes: SCR Catalyst – Conversion sufficient to achieve 2 ppmvd NO_x as NO₂ @ 15% O₂ in HRSG exhaust. CO Catalyst – Conversion sufficient to achieve 3 ppmvd CO @ 15% O₂ in HRSG exhaust. Duct burners for supplementary firing of high hydrogen shifted syngas.
Steam Turbine (ST)	1 x 100% Mitsubishi Heavy Industries Reheat turbine with single casing and single flow LP section. Nominal output of 150 MW at 97 °F and nominal pressures of 1870/400/50 psia. Sliding header pressure design. The Combustion Turbine and Steam Turbine drive the generator in a single-shaft arrangement.
Coal Drying Heat Source	CT exhaust gas extracted from the HRSG is used for coal drying. The dryer vent gas is vented through the dryer stack.
Plant Cooling	Process cooling water and ST Condenser cooling loads supplied by a mechanical-draft cooling system. Separate dedicated pumps handle water distribution to process users and the ST Condenser. A separate mechanical-draft cooling system included in the ASU scope of supply handles ASU cooling loads. Process air cooling to 140 °F. The process cooling water and ST Condenser cooling towers are designed for up to 9,000 ppmw TDS in the circulating water and 0.0005% drift eliminators. Selected

	cooling loads in the power block and gasification island utilize closed loop cooling systems.
Chemical Treatment for Cooling Systems	Includes applicable chemical dosing systems.
Elevated Flares	1 x 100% Gasification Flare. 1 x 100% SRU Flare. 1 x 100% Rectisol Flare.
Water Treatment System and ZLD	Raw water supplied from the Buena Vista Water Storage District brackish water wells. System includes the following: Raw water softeners for producing cooling tower make-up water. Blowdown softeners for treating cooling tower blowdown. Reverse Osmosis (RO) for waste concentration. Electro-deionization (EDI) for production of demineralized quality water. Oily water treatment. Two evaporator / crystallizers.
Potable Water	Potable water supplied via pipeline from local water district. Potable water distribution system.
Sanitary Waste Treatment	Sanitary waste discharge to on-site leach field.
Fire Protection	1 x 100% diesel firewater pump. 1 x 100% electric firewater pump. 1 x 100% pressure maintenance pump.
Plant and Instrument Air	Primary source is from the ASU. 1 x 100% Plant Service and Instrument Air Package (Backup).

Natural Gas Supply	1 x 100% From utility pipeline. Metering and regulation station at plant interface is by the utility. One high-flow natural gas compressor to supply the Combustion Turbine. One low-flow natural gas compressor to supply the Gasifier. One natural gas pressure reducing station for the low-pressure plant loads including the auxiliary boiler, etc. One chromatograph.
Nitrogen Distribution	1 x 100%
Drains and Blowdowns	1 x 100%
Auxiliary Boiler Package	1 x 100% Natural Gas fired package with NO_x controls sufficient to meet permit requirements. Net Steam production = 150,000 lb/hr @ 650 psig and 750 °F. Minimum Turndown is 22,500 lb/hr.
Emergency Generator (diesel)	2 x 50%. Generators provide 1,500 kW each.

General

Plant Configuration

1 x 100% oxygen-blown gasification train to produce syngas for ammonia synthesis and for power production. Ammonia is an intermediate product that is used to produce either solid urea pastilles or UAN-32 solution. The desired split between the two chemical products is 55% solid urea pastilles and 45% UAN-32 solution (by weight).

1 x 100% Mitsubishi Heavy Industries M501GAC Combustion Turbine / Steam Turbine / Generator on a single shaft.

1 x 100% HRSG with Reheat.

Plant Operating Philosophy

During “On-Peak” operation, the combustion turbine is operated at full load while the ammonia plant is turned down to nominally 60% of its design capacity. Clean high pressure syngas is also sent to the HRSG duct burner. The facility is to be operated in “On-Peak” mode for 16 hours per day throughout the entire year.

During “Off-Peak” operation, the combustion turbine is turned down to approximately 75% of its full capacity. The ammonia plant is operated at full capacity. The facility is operated in “Off-Peak” mode for 8 hours per day throughout the entire year.

The plant takes 60 minutes to ramp from “On-Peak” to “Off-Peak” and from “Off-Peak” to “On-Peak.”

Sufficient ammonia storage is provided to allow the production of solid urea pastilles and UAN solution at a constant rate during both “On-Peak and “Off-Peak” operation.

Fuel Usage

Normal gasifier feed is 25% coke and 75% coal (higher heating value basis).

Carbon Dioxide Emissions

Target during steady-state operation is to capture 90% of the carbon contained in the raw syngas. Captured carbon in the form of carbon dioxide is used for enhanced oil recovery and urea production.

Black Start Capability	Not Required.
Gasifier Turndown Capability	50% GID (Gasifier Input Demand).
Combustion Turbine Turndown Capability	To 60% of load while maintaining emission compliance on syngas. Combustion Turbine operates at approximately 75% load during “Off-Peak” mode.
Combustion Turbine Back-Up Fuel	Natural Gas (for operation during startup, shutdown and equipment outages).
Design Life	25 years.
Winterization	Electric tracing for freeze protection. Steam tracing only if needed for process conditions.

Feedstock Properties and Analysis

**Feedstock – Petroleum Coke
(Coke)**

High Sulfur Coke

Ultimate Analysis, wt. % (dry)

Carbon	84.4
Hydrogen	4.0
Nitrogen	4.0
Sulfur	6.0
Oxygen	0.6
Ash	1.0
Total	100.0

Moisture, wt. % (As Received) 15.0

Chloride Content, ppmw (dry) 250

Gross Heating Value, Btu/lb (dry) 14,579

Bulk Density, lb/ft³ (As Received) 50

Hardgrove Grindability Index (HGI) 30

Ash Analysis, ppmw (dry)

Vanadium	1,200
Nickel	1,200
Iron	1,000
Chromium	10
Sodium	400
Calcium	400

Feedstock - Coal

Lee Ranch Coal

Ultimate Analysis, wt. % (dry)

Carbon	60.40
Hydrogen	4.50
Nitrogen	1.00
Chlorine	0.01
Sulfur	1.09
Oxygen	11.70
Ash	21.30
Total	100.00

Moisture, wt. % (As Received) 14.8

Equilibrium Moisture, wt. % 14.4

Proximate Analysis, wt.
%

	As Received	Dry
Moisture	14.8	
Ash	18.1	21.3
Volatile Matter	33.4	39.2
Fixed Carbon	33.7	39.5
Total	100.0	100.0

Gross Heating Value, BTU/lb 9,253 10,860

Mercury (Hg), ppm (Dry Whole Coal Basis) 0.09

Lbs Hg / trillion BTUs 8.29

Hardgrove Grindability Index (HGI) @ 14.0% Moisture 55

Gasification Solids Viscosity @ T250 >2,900

Ash Fusion	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation (I.D.), °F	2,375	2,480
Softening (H=W), °F	2,475	2,575
Hemispherical (H=1/2W), °F	2,555	2,640
Fluid, °F	2,615	2,700
Ash Mineral Analysis, Ignited Basis		
Silicon Oxide, wt. %	59.3	
Aluminum Oxide, wt. %	22.9	
Titanium Dioxide, wt. %	1.0	
Sulfur Trioxide, wt. %	3.4	
Calcium Oxide, wt. %	4.8	
Potassium Oxide, wt. %	1.1	
Magnesium Oxide, wt. %	1.0	
Sodium Oxide, wt. %	0.4	
Iron Oxide, wt. %	5.7	
Phosphorous Oxide, wt. %	0.1	
Strontium Oxide, wt. %	0.1	
Barium Oxide, wt. %	0.2	
Manganese Dioxide, wt. %	< 0.1	
Alkalies as Na ₂ O	0.24	
Base/Acid Ratio	0.16	
Silica Value	83.76	
Lb Ash/MMBtu	19.6	
Lb Na ₂ O/MMBtu	0.08	

Products

Final Products

Electric Power

Basis for Net Electrical Output

At plant net output revenue meter.

Grid Interconnect:

High voltage take-off tower located in the switchyard. 230 kV.

Sulfur

Commercial grade degassed liquid sulfur.

- Purity = 99.90 wt. % min., dry basis.
- Bright yellow color.
- Carbon $\leq$ 500 ppmw.
- Acidity as $\text{H}_2\text{SO}_4 \leq$ 10 ppmw.
- Moisture $\leq$ 500 ppmw.
- H_2S in Liquid Sulfur $\leq$ 10 ppmw.

Solid Urea

Urea pastilles.

Urea Ammonium Nitrate (UAN) Solution

UAN-32.

- 34.0 – 37.0 wt. % urea.
- 42.0 – 47.0 wt. % ammonium nitrate.
- 17.0 – 24.0 wt. % water.
- $\leq$ 0.05 wt. % free ammonia.
- $\leq$ 0.30 wt. % biuret.

Carbon Dioxide (CO_2) Product for EOR

Carbon Dioxide (CO_2)	97.0 mol% (min)
Hydrocarbons($\text{C}_1\text{-C}_4$) + Ar + H_2	1.0 mol% (max)
Nitrogen (N_2)	2.0 mol% (max)
Oxygen (O_2)	10.0 ppmv (max)
Carbon Monoxide (CO)	1,200.0 ppmv (max)
Hydrogen Sulfide (H_2S)	20.0 ppmv (max)
Total Sulfur (H_2S + COS)	65.0 ppmv (max)
Sulfur Dioxide (SO_2)	10.0 ppmv (max)
Ammonia (NH_3)	1.0 ppmv (max)
Methanol (CH_3OH)	400.0 ppmv (max)
Water (H_2O)	13.0 ppmv (max)

Particulate Matter	1.0 ppmv (max)
Temperature	120°F (max)
Delivery Pressure	2,500 psig (min)

Gasification Solids:

Carbon Content	< 0.1 wt. %

Moisture Content	10-20 wt. % exiting the gasification island. Reduced to ~8 wt. % prior to shipment. Gasification solids must be sufficiently dry prior to shipment such that they contain no free liquids as defined in test method 9095B.

Intermediate Products

Ammonia	99.9 wt.% NH ₃ (anhydrous).

Nitric Acid	57 wt.% aqueous solution

Urea Solution (for UAN Production)	80% aqueous urea solution

Urea Melt (for Pastille Production)	Urea melt with ≤0.3% water

Ammonium Nitrate	79 wt.% aqueous solution

B. Environmental Design Criteria and Safety Requirements

1. Atmospheric Emission Sources

Coal Storage and Handling System:

- Feedstock Rail Unloading Vent.
- Transfer Tower 1.

Petcoke/Coal Storage and Handling System:

- Feedstock Truck Unloading Vent.

Coal-Petcoke Blend Handling System:

- Feedstock Crusher Vent.
- Transfer Tower 2.

Gasification Island:

- Gasification Feed Building Vent
- Feedstock Dryer.

Sulfur Recovery Unit:

- Tail Gas Thermal Oxidizer.

Flares:

- Gasification Flare.
- SRU Flare.
- Rectisol Flare.

Gasification Solids Storage and Handling:

- Gasification Solids Pad.
- Gasification Solids Bucket Elevator.
- Gasification Solids Loading Vent.
- Gasification Solids Transfer Tower.

Air Separation Unit (ASU):

- ASU Cooling Tower.

Combustion Turbine (CT):

- HRSG Stack.

Ammonia Unit:

- Start-Up Heater.

Urea Unit:

- Urea Absorber.

Urea Pastillation

- Urea Pastillation Vent.

Urea Storage and Handling:

- Urea Bucket Elevator.
- Urea Loading Vent.
- Urea Transfer Tower 1.
- Urea Transfer Tower 2.
- Urea Transfer Tower 3.
- Urea Transfer Tower 4.
- Urea Transfer Tower 5.

UAN Unit:

- Nitric Acid Absorber Vent.
- Ammonium Nitrate Scrubber Vent.

Miscellaneous:

- Process Cooling Tower.
- Power Block Cooling Tower.
- Auxiliary Boiler Stack.
- Diesel Engine Generator.
- Diesel Engine Firewater Pump.
- CO₂ Vent.

2. Process Design Criteria for Atmospheric Emissions

Parameter	Criteria:
NO _x as NO ₂	<u>SCR Design Criteria:</u> 2 ppmvd @ 15% O ₂ with syngas.
Sulfur in the Treated Syngas	≤ 2 ppmv (COS + H ₂ S).
SO _x as SO ₂	Resultant mass flow based on combustion of syngas with 2 ppmv total sulfur (COS + H ₂ S).
CO	CO Catalyst Design Criteria: 3 ppmvd @ 15% O ₂ with syngas.
VOC	1 ppmvd @ 15% O ₂ with syngas.
PM/PM-10/PM-2.5	The target for overall plant PM emissions is 95 TPY. The permit application is based on 15 lb/hr combined total PM from the HRSG and coal drying stacks.
NH ₃	5 ppmvd @ 15% O ₂ NH ₃ Slip.
Mercury	Limit of 0.003 lb/GW-h gross generation. 99% removal from syngas using activated alumina. 75% removal from coal drying exhaust to atmosphere using powdered activated carbon injection.
Maximum Stack Height	355 feet above grade.
Cooling Tower Drift Design Basis	0.0005% of cooling water flow rate.

i) Liquid Effluents

Source	Destination
Gasification Process Water Blowdown	Process RO
Storm/Surface Water – Process Units	Lined Retention Basins
Steam System Blowdown (cooled)	Cooling Tower
Demin System Wastewater	ZLD Clarifier
Cooling Tower Blowdown	Softener and RO
Gasification Solids Storage Pile Water	Gasification
Clarifier Effluent (Water)	Distribution/further treatment
Sanitary Wastes	On-site Leach Fields
Oil/Water Separators	Third party disposal with water effluent recycled
Clean Rainwater Retention Ponds	Percolation into the ground
Plant Wash-down Water	Solids removed then water recycled
Liquid Chemical Wastes	Captured and sent to third party disposal
Miscellaneous Plant and Transformer Oils	Third party disposal

ii) Solid Effluents

Source	Destination
Gasification Solids from Gasification	By rail or trucked offsite for sale or to landfill
Spent Carbon from Mercury Removal Bed	Trucked offsite as hazardous waste
Spent Shift Catalyst	Trucked offsite to reclaimer
Spent SCR Catalyst	Trucked offsite for disposal
Spent SRU Catalyst	Trucked offsite for disposal
Spent Nitric Acid Plant Catalyst	Trucked offsite to reclaimer
Evaporator Solid Waste	Trucked offsite to landfill
Clarifier Solid Waste	Offsite to third party disposal site

iii) Noise

Source	Limit
Near Field	85 dBA @ 3 ft from equipment or enclosure (Noise level from the pulverizers is 90 dBA)
Far Field	Design to local noise ordinances and project-specific CEC requirements

3.6.3 Engineering Design Criteria

Design criteria for the engineering disciplines of Health Safety & Environmental (HSE), Mechanical, Civil Structural and Architectural (CSA), Piping, Electrical, and Control Systems are provided in this section.

- Engineering and design for the “open art” and OSBL (utility and offsites) units is based on project-specific piping specifications that are consistent with Fluor and Industry Standards.
- Engineering and design for Licensors Units is based on data furnished by the Licensors. This data was developed by the Licensors using their proprietary and confidential design specifications, P&IDs, equipment sizes, and equipment arrangements. Licensor design documentation was used “as-received” and is protected from FOIA release by License Agreements and/or by non-Disclosure Agreements (NDAs).
- Formal process hazard analyses (PHAs/HAZOPs), including assignment and verification of safety integrity level (SIL), are not part of the FEED and were to be performed in the next phase of engineering.
- As a power generation facility exceeding 50 MW of generating capacity, the HECA Project is subject to certification by the California Energy Commission (CEC). This certification is the primary environmental approval for the project and also includes a determination of compliance with the California Environmental Quality Act (CEQA). The project Application for Certification (AFC) to the CEC is a comprehensive project description and environmental evaluation that identifies the environmental requirements for the project and the means by which HECA proposes to comply with these requirements. The AFC is identified as Amended Application for Certification for Hydrogen Energy California (08-AFC-8), Kern County, California, May 2012.
- In some cases, the project environmental design criteria presented in the Process Design Basis, is intentionally more stringent than the environmental permit limits proposed in the AFC.
- In general, project occupational noise exposure will be limited to 85 dBA, eight-hour average. Fence-line and offsite noise limits are based on the applicable Kern County and CEC standards and may be the controlling requirements for some equipment items.

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- The mechanical equipment design is based upon Fluor guidelines, industry applicable equipment codes and standards, government regulations and requirements, licenser requirements, and Process, Electrical, Control Systems, and CSA design requirements.
 - Mechanical equipment design considerations include requirements for materials, painting, insulation, galvanizing, refractory, linings, and welding.
 - Vessel design includes requirements for ladders and platforms, internal ladders, mist eliminators, vortex breakers, pipe support details, pipe guide details, hinge and davit details, insulation supports, skirt details, saddle details, and electrical grounding connections.
 - Drainage design follows a zero liquid discharge (ZLD) philosophy, while the site earthwork design philosophy employed the use of mass excavations and perimeter berms to mitigate native spoils replaced by imported granular soil backfill materials.
 - The plot plan and preliminary mechanical equipment information were used as the basis for developing layouts to establish the grading, drainage and paving limits. Topographic and boundary survey data was utilized for the underground and aboveground gravity drainage system designs as well as manually preparing the earthwork cut & fill sections to achieve the desired finish elevations and surfaces.
 - Preliminary mechanical equipment information was used as the basis for developing foundation sizes and structural steel member sizes when the equipment was to be supported in a structure. Equipment support structures, access platforms and pipe rack sizes and layouts were provided by piping engineering and design. Foundation designs utilized spread footings and were sized based on the equipment type and industry practices, allowable soil bearing values, and overall stability recommendation specified in the geotechnical report.
 - Above grade concrete and steel structures were sized using RISA-3D analysis models, manual calculations, historical designs, and engineering judgment. Structure designs were based on the preliminary equipment sizes and weights, layouts, consideration for access and egress requirements, serviceability and seismic drift requirements.
 - Buildings included:
 - 1) Control Room, Administration, Laboratory and Medical Aid Building
 - 2) Maintenance and Warehouse Building
 - 3) Main Security Guard House
 - 4) Emergency Response Vehicle Shelter

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- 5) Urea Pastillation Building
 - 6) Operator Shelters
 - Building structure type and exterior envelope are specified as “Pre-engineered Metal Building.”
 - Normally occupied spaces other than Maintenance Shops and Warehouses are air-conditioned. All other spaces are heated and ventilated only.
 - Operator Shelters & Guard Houses are pre-manufactured units. Operator Shelters are blast resistant structures with the blast rating based on shelter location and hazard analysis.
 - Emergency Response Vehicle Shelter provides covered parking for two emergency response trucks along with a small storage for fire fighting and safety equipment.
 - Piping insulation, steam tracing and electric tracing requirements are specified on design documents and are in accordance with the project specifications.
 - Electrical systems and equipment that are outside of Fluor’s FEED scope and that are specified and designed by the Owner are listed below:
 - 1) New PG & E Switching Station.
 - 2) 230 kV Transmission Line from the PG & E Switching Station to the HECA on-site Switchyard incoming disconnect switch take-off tower.
 - 3) The Air Separation Unit (ASU) is 3rd Party Design, Build, Own and Operate (DBOO). The 230 kV Transmission Line for the ASU is located on the same pole as the HECA 230 kV Transmission Line.
 - Plant voltages are as specified in the Electrical Systems Data section of this document.
 - ETAP software was utilized for short circuit, load flow, motor starting, cable de-rating, relay settings and coordination.
 - Electrical heat tracing is specified where required for freeze protection and process heating. Electrical heat tracing consists of self-regulating heat-tracing cable, thermostats, heat-tracing panels with main contactor and circuit breaker panels.
 - Whenever possible, instruments are close coupled with impulse tubing minimized. Field instruments are to be wired to remote I/O boxes in the field and home-run digital cables to RIE DCS cabinet or panels.

-
- Wireless transmitters are specified for non-critical applications such as indications and general alarms.
 - The project utilizes an Integrated Control and Safety system (ICSS) to monitor, control, operate, maintain and manage operations. The ICSS resides in the Central Control Room, in a safe and secure environment. The ICSS is capable of providing proper plant performance under various operating scenarios and plant throughput capabilities.
 - Multi-level system architecture is provided with security levels between each level in order to prevent accidental manipulation of plant operations.
 - A separate communication network is specified for integrating business and enterprise management systems. The process control network and the communication network are independent such that the process control network does not permit any use or function other than process control, process safety and monitoring.
 - The communication systems include General Alarm (GA) or paging systems, VHF/UHF radio systems, camera surveillance/badge reader system, telephone equipment, and general purpose communications associated with Ethernet or fiber optic networks.

3.7 SYSTEM DESCRIPTIONS

The narratives that describe the major systems of the HECA Project are provided in this section. These descriptions outline the respective system's function, design basis, and major components.

Descriptions for open art non-proprietary systems contain more technical and narrative detail than those that utilize Confidential Licensed Technology that is protected from FOIA release by License Agreements and/or by Non-Disclosure Agreements (NDAs) and are therefore considered "Limited Rights Data" under Government Agreement No. DE-FE0000663. Non-confidential overviews are provided for the systems that contain Licensed Technology.

It is noted that the design cases described within the unit system descriptions are unique to that system description and are not to be confused with the six (6) Overall Operating Cases defined in Section 3.3, Plant Performance. The design cases within unit system descriptions address items such as feedstock blend, start-of-run and end-of-run catalyst performance, partial-load operation, etc.

The Process Flow Diagrams corresponding to these system descriptions are provided in Section 3.8.

3.7.1 Gasification

The Gasification Area is required for converting solid feedstocks into syngas. The raw syngas (primarily composed of CO and H₂) is further processed downstream in the Gas Treating Area to produce hydrogen-rich fuel.

A technical evaluation led to the selection of Mitsubishi Heavy Industries (MHI) for their oxygen-blown dry-feed gasification technology. MHI prepared a Confidential Process Design Package (PDP) during FEED that applied their proprietary gasification technology to the HECA Project. The overview that follows is a non-confidential description of the HECA gasification system.

A. Design Basis

i) Unit Capacity

The Gasification Area is designed to handle 5,773 sTPD of coal and petcoke feedstock. The thermal input rating for the Gasification Area is 1,250 MW.

ii) Design Cases

This project will use a blend of 75% coal and 25% petcoke on a thermal basis.

iii) Feed Source

The source of western sub-bituminous coal is Lee Ranch coal mine in New Mexico. Petcoke is sourced from refineries in the Southern California area. The feedstocks are blended and crushed in the upstream Feedstock Unloading, Handling & Storage System prior to being conveyed to the Gasification Area.

B. Process Description

Within the Gasification Area, feedstock is ground, dried, then fed to the gasifier. The MHI oxygen-blown gasifier is a pressurized, upflow, entrained-flow slagging reactor with a two-stage operation. The reactor internals are protected by a membrane wall.

The first (lower) stage is fed a portion of the feed along with O₂, where it is gasified at a high temperature to produce CO, CO₂, and water vapor. The temperature generated is sufficiently high to melt the coal ash. The molten coal ash flows down the membrane wall to the bottom of the gasifier, where it is quenched in a water bath and then removed using a lock hopper system.

The gas produced in the first stage rises to the second stage, where the remaining feed is added without any additional O₂. In this fuel-rich reducing environment, the key reactions that take place are: 1) the gasification of char to CO; and 2) the shifting of CO and water to hydrogen and CO₂. Heat provided by the hot gas from the first stage is used to drive these endothermic gasification reactions. As a result, the second stage operates at a lower temperature than the first stage. Completing the gasification reactions at a lower temperature reduces the O₂ required and improves the efficiency of the gasifier.

The syngas produced exits the second stage through a syngas cooler, generating steam for use in power generation. A cyclone and a filter are used downstream of the syngas cooler to collect the char and recycle it to the lower section to increase the overall carbon conversion efficiency. The raw syngas leaving the second stage of the gasifier is typically at a temperature of approximately 2,200 °F, hot enough that negligible hydrocarbon gases and liquids are formed.

3.7.2 Gas Treating

The plant configuration requires a Gas Treating Area to process the raw syngas from Gasification.

The main objective of the Gas Treating Area is to convert the CO and H₂O in the raw syngas into H₂ and CO₂ via the water gas shift reaction so that the requirements for the Fertilizer Complex and the Power Block can be met. The Gas Treating Area also processes the recycle tail gas from the Sulfur Recovery Unit (SRU), sour water from the SRU, and KO drum liquid from the flare system.

The shifted sour syngas is routed to the downstream Acid Gas Removal (AGR) Unit to remove the acid gas components. The stripper overhead sour gas is routed to the SRU. The waste water is sent to the Waste Water Treatment Plant for further processing.

The overall configuration for the Gas Treating Area is shown below in Figure 3-6.

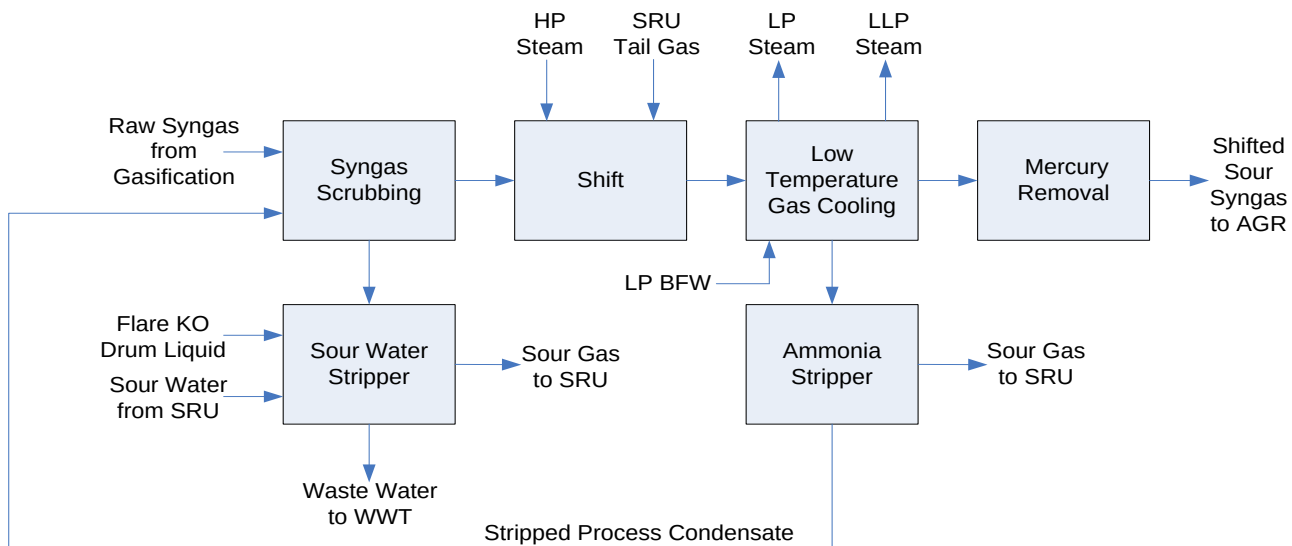


Figure 3-6: Gas Treating Area Overall Configuration

A. Design Basis

i) Unit Capacity

The Gas Treating Area is designed to handle 380 MMSCFD (400 MT/hr) of raw syngas from Gasification with approximately 46 vol% of carbon monoxide and 27 vol% of hydrogen in the feed stream.

ii) Design Cases

Design of the Gas Treating Area is based on the five (5) cases outlined in the table below.

Table 3-23: Case Definition – Gas Treating Area

Cases	Description
020-01	75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100%, Shift @ End of Run (EOR)
020-02	75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100%, Shift @ Start of Run (SOR)
020-03	75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 50%, Shift @ Start of Run (SOR)
020-04	75% Lee Ranch Coal and 25% Petroleum Coke containing 1.16 wt% sulfur, Gasifier @ 50%, Shift @ End of Run (EOR)
020-05	100% Lee Ranch Coal, Gasifier @ 100%, Shift @ End of Run (EOR)

iii) Feed Source

The Gas Treating Area receives raw syngas from Gasification, as well as recycle tail gas from the SRU, sour water from the SRU, and KO drum liquid from the flare system.

iv) Product Specifications

The Gas Treating Area has three product streams: shifted and cooled sour syngas stream routed to the Acid Gas Removal (AGR) unit, acid gas stream routed to the Sulfur Recovery Unit (SRU), and a waste water stream routed to the Waste Water Treatment (WWT) plant. The key product specifications are listed below.

1. Shifted Sour Syngas

- 96.4% conversion of CO to CO₂ from raw syngas
- Maximum of 1 ppmv NH₃

2. Waste Water

- Maximum of 1000 ppmw Chlorides
- Maximum of 50 ppmw H₂S

3. Sour Gas to SRU

There are no product specifications for this stream. However, operators should avoid sending excessive nitrogen to SRU as this increases the inert traffic through the SRU and therefore reduces the unit processing capacity.

B. Process Description

i) Syngas Scrubbing

Hot raw syngas from Gasification is fed to the Syngas Scrubber (020-V-001). The battery limit conditions are 663 psig and 774 °F. The purpose of the scrubber is to remove chlorides, remove particulates and saturate the syngas with water. The Syngas Scrubber (020-V-001) consists of two major zones: a quench and wash zone with grid packing and a chloride scrubbing zone with 4 sieve trays.

The syngas scrubber bottoms is pumped via the Syngas Scrubber Circulation Pump (020-P-001 A/B) where the majority of the flow is pumped through the Syngas Scrubber Circulation Cooler (020-E-015) under flow control feeding the quench and wash zone. A high circulation rate is required to ensure adequate quenching and washing of the hot raw syngas. Proper saturation of syngas reduces the amount of steam injection necessary to meet the water to carbon monoxide ratio required for the shift reaction. The remainder of the syngas scrubber bottoms is pumped under level cascading to flow control to the Ammonia Stripper Feed Preheater (020-E-031) and ultimately the SWS Feed Drum (020-V-021).

Stripped process condensate from the Ammonia Stripper (020-V-032) is heated in the Scrubber Feed Water Heater (020-E-006) and then fed to the Syngas Scrubber (020-V-001) chloride scrubbing zone. After the syngas has been quenched, hot stripped process condensate is used as scrubbing media to remove chlorides. Removal of chlorides in the scrubber minimizes the potential for ammonia chlorides to precipitate in downstream equipment as the syngas is cooled further.

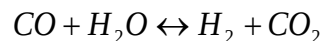
The overhead of the Syngas Scrubber (020-V-001) is injected with 700 psig high pressure (HP) steam. The purpose of steam injection is to meet the steam to carbon monoxide ratio required for catalytic shift conversion. The steam is a blend of saturated steam produced in the Process Steam Generator (020-E-003) and make-up superheated steam from OSBL.

After injection, the syngas is fed to the Syngas Scrubber KO Drum (020-V-002) to remove liquid carry over from the Syngas Scrubber (020-V-001) and condensation during steam injection. The KO drum liquid is routed to the SWS Feed Drum (020-V-021).

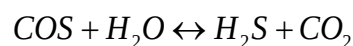
ii) Shift

Scrubbed raw syngas from the Scrubber KO Drum (020-V-002) is heated on the tube side of the Shift/Feed Effluent Exchanger (020-E-001) by exchanging heat with hot partially shifted syngas from the Process Steam Generator (020-E-003 A/B) on the shell side. The scrubbed raw syngas then is fed to the First Stage Reactor (020-R-001 A/B). The inlet temperature to the First Stage Reactor (020-R-001 A/B) is maintained at about 479 °F at EOR with a temperature controller which modulates the bypass flow around the tubeside of 020-E-001. The First Stage Shift Reactor consists of two reactors in parallel.

Shift catalyst is a sulfur-tolerant catalyst bed composed of cobalt and molybdenum oxides. The catalyst converts the CO and H₂O of the raw syngas into H₂ and CO₂ via the water gas shift reaction.



The catalyst also promotes the hydrolysis of carbonyl sulfide (COS) to hydrogen sulfide (H₂S).



The reactions above are exothermic. Low temperature and high steam ratios drive the equilibrium to the left and convert more CO and COS to the desired products. The catalyst also promotes the hydrolysis of hydrogen cyanide (HCN) to ammonia (NH₃). 81.1% CO conversion is achieved in the first stage with a steam to CO ratio of 2.13 at SOR and 2.05 at EOR.

Partially shifted syngas at 850 °F exits the First Stage Reactor (020-R-001 A/B) and is cooled before entering the Second Stage Reactor (020-R-002 A/B) for further shift conversion. Partially shifted syngas from 020-R-001 A/B is routed to the Process Steam Generator (020-E-003 A/B) where 700 psig HP steam is produced from process condensate. The inlet temperature to the Second Stage Reactor (020-R-002 A/B) is maintained with a

temperature controller which modulates the bypass flow around the tubeside of 020-E-003 A/B.

The partially shifted syngas is then further cooled in the Shift Feed/Effluent Exchanger (020-E-001). Compressed tail gas, recycled from the Sulfur Recovery Unit (SRU), is injected into the partially shifted syngas at this point. This eliminates the need for a thermal oxidizer usually required for the SRU. The compressed tail gas is a relatively small stream compared to the syngas stream.

After the compressed tail gas is injected, the partially shifted syngas is cooled on the tube-side of the Scrubber Feed Water Heater (020-E-006) by exchanging heat with process condensate on the shell-side before being fed to the Second Stage Reactor (020-R-002 A/B).

The Second Stage Shift Reactor consists of two reactors in parallel with sulfur-tolerant catalyst beds composed of cobalt and molybdenum oxides similar to the first stage. 81% CO conversion is achieved in the second stage achieving the product spec of 96.4% overall CO conversion.

Shifted syngas exiting the Second Stage Reactor (020-R-002 A/B) is cooled in the low temperature gas cooling section before being sent to the Acid Gas Removal (AGR) Unit for further processing.

iii) Low Temperature Gas Cooling

Shifted syngas from Second Stage Reactor (020-R-002 A/B) is cooled on the shell side of the Process Condensate Heater (020-E-004) by exchanging heat with process condensate from the Process Condensate Pump (020-P-001 A/B).

Shifted syngas is then sent to the tube-side of the Shift LP Steam Generator (020-E-007 A/B/C) generating 65 psig low pressure (LP) steam from LP boiler feed water (BFW). The LP steam is exported to the Power Block to generate power in the Steam Turbine Generator (STG).

The shifted syngas stream from 020-E-007 A/B/C is a two phase mixture and is routed to the Shift KO Drum #1 (020-V-003) for vapor and liquid separation. The liquid is routed to the Process Condensate Receiver (020-V-007) under level control.

The vapor from 020-V-003 is fed to the LLP Steam Generator (020-E-008 A/B) to generate 45 psig low low pressure (LLP) steam from LP BFW. The LLP steam is used for steam reboiling in the Sour Water Stripper (020-V-022) and live steam injection in the Ammonia Stripper (020-V-032). The remaining LP steam is sent to the deaerator in the Power Block.

The shifted syngas from 020-E-008 A/B is cooled on the shell-side of the Demin Water Heater (020-E-009) by exchanging heat with demin water on the tubeside. Demin water is heated in the Gas Treating Area and routed to the deaerator in the Power Block.

The shifted syngas stream from 020-E-009 is a two phase mixture and is routed to the Shift KO Drum #2 (020-V-004) for vapor and liquid separation. The liquid is routed to the Process Condensate Receiver (020-V-007) under level control.

The Process Condensate Receiver (020-V-007) collects condensate from the Shift KO Drum #1 (020-V-003) and Shift KO Drum #2 (020-V-004). The process condensate is recycled and used for HP steam generation. The Process Condensate Pump (020-P-002 A/B) pumps condensate to the Process Condensate Heater (020-E-004) and ultimately the Process Steam Generator (020-E-003). Excess condensate is sent to the Ammonia Stripper Feed Drum (020-V-031) under level cascading to flow control.

The vapor from 020-V-005 is fed to the Shift Air Cooler (020-E-010 A-I). The two phase mixture exiting the air cooler is sent to the Shift KO Drum #3 (020-V-005) for vapor and liquid separation. The liquid is routed to the Ammonia Stripper Feed Drum (020-V-031) under level control.

The vapor from the 020-V-005 is cooled further in the Shift Water Cooler (020-E-011) to a temperature appropriate for ammonia removal. The shifted syngas from 020-E-011 is washed with cooled HP BFW in the Ammonia Wash Column (020-V-006). The Ammonia Wash Column consists of 6 bubble cap trays to reduce the ammonia content of the shifted sour syngas to a maximum of 1 ppmv. The column bottoms are sent to the Ammonia Stripper Feed Drum (020-V-031) under level control.

iv) Mercury Removal

Shifted syngas from the Ammonia wash Column (020-V-006) is then heated in the tube-side of the Mercury Removal Feed Heater (020-V-012) by exchanging heat with demin water on the shell-side. Some heat is removed from the demin water before it is sent to the Power Block. The shifted syngas needs to be superheated to avoid condensation on the Mercury Removal Reactor (020-R-003) catalyst bed.

Shifted Syngas enters the Mercury Removal Reactor (020-R-003) where mercury present will be absorbed from shifted syngas with 99% efficiency over an activated carbon bed in a single reactor. In addition to mercury removal, benzene, toluene and xylene are also removed completely. The shifted syngas is then cooled in the Mercury Removal Aftercooler (020-E-013) with cooling water. The shifted syngas product from the Gas Treating Area is sent to the AGR for further processing. The battery limit conditions are 540 psig and 105 °F.

v) Sour Water Stripper

The SWS Feed Drum (020-V-021) collects sour water from the Syngas Scrubber (020-V-001), SRU and the Flare Knockout Drums. The sour water is flashed in the SWS Feed Drum (020-V-021) at 19.5 psig. Flash gas from this drum is sent to the Sour Water Stripper (020-V-022). The SWS Feed Pump (020-P-021 A/B) pumps sour water from this drum to the Sour Water Stripper.

The Sour Water Stripper is equipped with 40 valve trays and a steam reboiler to separate H₂S, NH₃ and HCN from the sour water. The column reduces the H₂S content of the bottoms stream to a maximum of 50 ppmw. The column uses a pump-around cooling loop to provide column reflux and to maintain column temperature. Caustic is injected into the Sour Water Stripper to aid in stripping ammonia. The Caustic Injection Pump (020-P-024 A/B) pumps 20° Be caustic from the Fresh Caustic Tank (020-TK-001) to the Sour Water Stripper. The Sour Water Stripper overhead is sent to the SRU.

The SWS Reboiler (020-E-025), a thermosiphon, shell and tube reboiler provides the required heat for fractionation.

The pumparound (PA) liquid is drawn off the chimney tray below tray #36. The SWS PA Pump (020-P-023 A/B) circulates it through the SWS PA Air Cooler (020-E-023) for heat removal and returns to the top tray #40 for column reflux. The PA duty is controlled by the temperature controller on the stripper overhead stream, which cascades to a separate temperature controller on the PA return stream and modulates the variable frequency drive of the air cooler fans. The stripper overhead temperature is maintained at 190 °F.

The Sour Water Stripper bottoms is pumped via the Stripped Sour Water Pump (020-P-022 A/B) through the Stripped SW Air Cooler (020-E-026). Waste water is sent to the waste water treatment plant.

vi) Ammonia Stripper

The Ammonia Stripper Feed Drum (020-V-031) collects process condensate from the Process Condensate Receiver (020-V-007), Shift KO Drum #3 (020-V-005) and Ammonia Wash Column (020-V-006). The process condensate is flashed in the Ammonia Stripper Feed Drum (020-V-031) at 19.5 psig. Flash gas from this drum is sent to the Ammonia Stripper (020-V-032).

The Ammonia Stripper Feed Pump (020-P-031) pumps process condensate from the Ammonia Stripper Feed Drum through the Ammonia Stripper Feed Preheater (020-E-031) to the Ammonia Stripper. Process condensate is heated in 020-E-031 by exchanging heat with sour water from the Syngas Scrubber.

The Ammonia Stripper is equipped with 40 valve trays and steam injection to separate H₂S and NH₃ from process condensate. The steam injection provides the required heat for fractionation. The column reduces the NH₃ content of the bottoms stream to a maximum of 100 ppmw. The column uses a pumparound cooling loop to provide column reflux and to maintain column temperature. The Ammonia Stripper overhead is sent to the SRU.

The pumparound (PA) liquid is drawn off the chimney tray below tray #36. The Ammonia Stripper PA Pump (020-P-033 A/B) circulates it through the Ammonia Stripper PA Air Cooler (020-E-033) for heat removal and returns to the top tray #40 for column reflux. The PA duty is controlled by the temperature controller on the stripper overhead stream, which cascades to a separate temperature controller on the PA return stream and modulates the variable frequency drive of the air cooler fans. The stripper overhead temperature is maintained at 190 °F.

The stripped process condensate from the Ammonia Stripper is pumped by the Stripped Process Condensate Pump (020-P-022 A/B) and routed to the Scrubber Feed Water Heater (020-E-006). The stripped process condensate ultimately is used as feed water for chloride scrubbing in the Syngas Scrubber (020-V-001).

vii) Steam Condensate

The LLP Condensate Drum (020-V-041) collects LLP condensate from the SWS Reboiler (020-E-025), Start-Up Gas Heater (020-E-002) and LLP steam header traps. LLP condensate is flashed close to atmospheric in the LLP Condensate Drum (020-V-041). Flash steam is vented to the atmosphere. The LLP Condensate Pump (020-P-041 A/B) pumps condensate from 020-V-041 and sends it to the deaerator in the Power Block.

The Blowdown Drum (020-V-044) collects continuous and intermittent blowdown from the LP Steam Generator (020-E-007) and LLP Steam Generator (020-V-008). Blowdown is flashed close to atmospheric in the Blowdown Drum (020-V-044). Flash steam is vented to the atmosphere. The Blowdown Pump (020-P-044 A/B) pumps condensate from 020-V-044 and sends it into the cooling water return header.

viii) Start-Up Gas

During start-up, the Start-Up Ejector System (020-EJ-001) uses HP steam to first remove air from the Gas Treating Area. Then it is pressurized to about 100 psig with nitrogen. The Start-Up Gas Compressor (020-C-001) recycles nitrogen through the Syngas Scrubber KO Drum to the Shift KO Drum #3 reducing the overall nitrogen required during start-up to maintain pressure. The recycled gas is heated in the Start-Up Gas Heater (020-E-002) to 500 °F. After the system is heated, dimethyl disulfide (DMDs) from the DMDs Injection Package is injected into the start-up gas stream which is used to sulfide the catalyst in the

First and Second Stage Reactors. Sulfiding in-situ occurs at temperatures above 400 °F. When sulfiding is completed, the start-up gas system needs to be isolated from the syngas flow path before raw syngas is introduced to the unit. If sulfiding is not required, syngas can be introduced to the system after warm-up and isolation.

C. Operating Flexibility

i) Turndown

The Gas Treating Area is designed for 50% turndown.

ii) Equipment Design Factors

The equipment is designed for 100% EOR operation with an exception being for the Sour Water Stripper and the Ammonia Stripper systems that are both designed to process 110% of the normal sour water feed rate.

iii) Sparing Philosophy

All pumps are 100% spared.

The Ammonia Stripper system has piping arrangements so that it can be bypassed and its feed stream can be sent to the Sour Water Stripper system.

iv) Reliability

The catalyst life of the sour shift reactors is greatly influenced by the gas quality (syngas poisons and entrainment). Process condensate, soot, carbonyls or tars have the potential to be deposited on the surface of the catalyst decreasing the activity. Furthermore, catalyst life will depend on the control of the ratio of H₂O to CO, as well as the temperature of the reactor.

v) Start-up and Shutdown

Storage capacity is not provided for between Gasification, Gas Treating, and the AGR Unit. Gasification, Gas Treating, and the AGR Unit will all need to be started up and shutdown together. Gas Treating does not have the flexibility to operate independently.

3.7.3 Acid Gas Removal Unit

The Acid Gas Removal (AGR) Unit is required for purification of the shifted sour syngas stream from Gas Treating. A technical evaluation led to the selection of Linde's proprietary Rectisol wash technology to meet the HECA project's acid gas removal requirements. A Confidential Process Design Package (PDP) was prepared during FEED and is protected by an NDA. This section provides a non-confidential overview of the HECA AGR Unit.

A. Design Basis

i) Unit Capacity

The Acid Gas Removal Unit is designed to handle a nominal 530 MMSCFD of shifted sour syngas from Gas Treating.

ii) Design Cases

The design of the AGR Unit is based on the following five (5) cases outlined in the table below.

Table 3-24: Case Definition – Acid Gas Removal Unit

Cases	Description
031-01	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100% load, Shift @ normal End of Run (EOR); On-Peak operation @ 97°F Ambient
031-02	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100% load, Shift @ normal Start of Run (SOR); On-Peak operation @ 97°F Ambient
031-03	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 50% load, Shift @ normal Start of Run (SOR); @ 97°F Ambient
031-04	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 1.16 wt% sulfur, Gasifier @ 50% load, Shift @ normal End of Run (EOR); @ 97°F Ambient
031-05	Gasifier feed consisting of 100% Lee Ranch Coal, Gasifier @ 100% load, Shift @ normal End of Run (EOR); On-Peak operation @ 97°F Ambient

iii) Feed Source

The AGR Unit is fed sour, shifted syngas from Gas Treating.

Liquid propylene refrigerant is supplied by the Acid Gas Refrigeration Unit. Instrument air, cooling water, nitrogen, steam, and other utilities are supplied from the OSBL units.

iv) Product Specifications

The AGR Unit produces the following streams:

4. A hydrogen-rich sweet syngas stream with low sulfur content and low carbon dioxide content that can be used for the cogeneration of electric power and chemicals.
5. A product carbon dioxide stream that meets the “pipeline” gas specification, and which can be safely vented to the atmosphere (e.g. during plant startups or upsets) after being sent through a wash column.
6. An acid gas stream suitable for feeding an oxygen-blown Claus Sulfur Recovery Unit (SRU).

The product and co-product gas specifications are provided in the following tables.

Table 3-25: Clean Syngas Stream Specification

Total Sulfur (H ₂ S + COS)	2.00 ppmv (max)
CO ₂	2.00 mol % (max)
HCN	0.10 ppmv (max)
Fe(CO) ₅	0.01 ppmv (max)
Ni(CO) ₄	0.05 ppmv (max)

Table 3-26: Acid Gas Stream Specification

Total Sulfur (H ₂ S + COS) Concentration	45 mol % (min)
Pressure at AGR battery limit	30 psia (min)

Table 3-27: CO₂ Gas Stream Specification

Carbon Dioxide (CO ₂)	97.0 mol % (min)
Hydrocarbons (C1-C4) + Argon (Ar) + Hydrogen (H ₂) (Note 2)	1.0 mol % (max)
Nitrogen (N ₂)	2.0 mol % (max)
Oxygen (O ₂)	10.0 ppmv (max)
Carbon Monoxide (CO)	1,200.0 ppmv (max)
Hydrogen Sulfide (H ₂ S) (Note 3)	20.0 ppmv (max)
Total Sulfur (H ₂ S + COS)	65.0 ppmv (max)
Sulfur Dioxide (SO ₂)	10.0 ppmv (max)
Ammonia (NH ₃)	1.0 ppmv (max)
Methanol (CH ₃ OH) (Note 4)	400 ppmv (max)
Water (H ₂ O) (Note 5)	13 ppmv (max)

Notes:

1. At AGR unit battery limit.
2. Minimize H₂ content in the medium pressure CO₂ product stream. Maximum H₂ content in the low pressure CO₂ product stream is 0.1 mole%.
3. Maximum H₂S concentration is 10 ppmv when venting to the atmosphere.
4. Maximum methanol concentration is 40 ppmv when venting to the atmosphere.
5. Less than 0.61 lbs per MMSCF (dew point 11 °F, no free water).

B. Process Description

The majority of the design falls under Linde's proprietary licensed technology, which utilizes methanol as a solvent for acid gas removal. A generic overview of the Rectisol wash technology and a description of non-proprietary equipment within the AGR Unit are provided in the paragraphs that follow.

i) General

The shifted sour syngas feed is chilled prior to entering the pre-wash section, in which condensed or dissolved impurities are removed. The gas then flows to the absorber column, where it is contacted with methanol solvent for absorption of H₂S, other sulfur compounds, and CO₂.

Clean, hydrogen-rich fuel (very low in sulfur compounds and CO₂) exits the top of the absorber column. The clean, hydrogen-rich fuel is heated and sent to the Combined Cycle Power Block for use as fuel or to the PSA Unit for further purification.

The hydrogen-sulfide-laden solvent is withdrawn from the absorber column and flashed, with the flash gas being recycled to the absorber column and the separated liquid solvent sent to CO₂-separation columns. Carbon-dioxide-laden solvent from the absorber column is also sent to the CO₂-separation columns.

Separated CO₂ exits the top of the CO₂-separation columns and flows to the CO₂ Compression & Purification Unit.

CO₂-free solvent exiting the bottom of the CO₂-separation columns flows to the hot regenerator where H₂S and other sulfur compounds are released from the solvent by increasing the temperature and stripping with methanol vapor generated in a reboiler. The separated acid gas exiting the top of the hot regenerator undergoes further processing in the SRU to recover liquid sulfur as a product.

The regenerated methanol solvent exiting the bottom of the hot regenerator, now CO₂ and H₂S-free, is cooled and returned to the absorber column for reuse.

A small portion of the regenerated solvent is sent to the methanol-water column for separation of water and impurities from the methanol by distillation. The methanol-rich overhead stream from the methanol-water column is returned to the hot regenerator.

ii) Wastewater Cooler

Wastewater from the Methanol/Water Separation Column is normally at about 280 °F. Before leaving the unit for processing, the stream is cooled 140 °F by the Wastewater Cooler. Water treatment requires the temperature to be 140 °F or less. The Wastewater Cooler uses cooling water to cool the wastewater before it is pumped from the unit.

iii) Wastewater Pump I

After being cooled, the wastewater is pumped by Wastewater Pump I to the wastewater header. Wastewater Pump I pumps the wastewater from about 25 psig to 113 psig, where it joins wastewater from Wastewater Pump II and the CO₂ Water Wash Pump before leaving the unit. Wastewater Pump I is controlled on flow control and has a minimum flow bypass.

iv) Wastewater Pump II

Potable water used to wash nitrogen in the Water Seal Pot, is pumped by Wastewater Pump II, 031-P-052. The wastewater is pumped from about 2 psig to about 117 psig and joins the other wastewater streams to exit the unit. Wastewater Pump II is controlled on flow control and has a minimum flow bypass.

v) Atmospheric Condensate Flash Drum

LP steam/condensate from the hot regeneration reboiler and MP steam/condensate from the methanol/water separation reboiler are combined and sent to the Atmospheric

Condensate Flash Drum. The drum flashes the vapor/liquid stream at atmospheric pressure; steam leaves the top through an exhaust head and condensate leaves the bottom.

vi) Condensate Pump

Condensate from the Atmospheric Condensate Flash Drum is pumped from the unit by the Condensate Pump. The condensate is pumped from about 5 psig to 194 psig. The Condensate Pump is controlled on level in the Atmospheric Condensate Flash Drum.

C. Operating Flexibility

i) Turndown

The AGR Unit is designed to operate at 50% of design capacity.

ii) Sparing Philosophy

Pumps in continuous service are spared; no other equipment is spared.

iii) Reliability Issues

There is no known reliability issues associated with this system.

3.7.4 Acid Gas Removal Refrigeration Unit

The AGR Refrigeration Unit provides the methanol cooling required in the AGR Unit.

Propylene (R-1270) is used as the refrigerant, which is sent to the AGR as a liquid and returns as a gas. Within the AGR Refrigeration Unit, the gas is compressed, condensed, cooled, and then sent back to the AGR.

The Refrigeration Unit is a Vendor Packaged Unit, with equipment provided on skids. The unit consists of two 50% compressor trains, each with separate condensers, subcoolers, and operating receiver. A single refrigerant storage vessel is common between the two trains.

A. Design Basis

i) Unit Capacity

The unit is designed to provide 68.65 MMBtu/hr of liquid refrigerant at 223 psia and 5.6 °F (5,721 tons of refrigeration). The compressors are designed for vapor refrigerant returned at 18.6 psia and -30 °F.

ii) Design Cases

The design of the AGR Refrigeration Unit is based on the cases described in the table below.

Table 3-28: Case Definition - AGR Refrigeration Unit

Cases	Description
032-01	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100% load, Shift @ normal End of Run (EOR); On-Peak operation @ 97°F Ambient
032-02	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100% load, Shift @ normal Start of Run (SOR); On-Peak operation @ 97°F Ambient
032-03	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 50% load, Shift @ normal Start of Run (SOR); @ 97°F Ambient
032-04	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 1.16 wt% sulfur, Gasifier @ 50% load, Shift @ normal End of Run (EOR); @ 97°F Ambient
032-05	Gasifier feed consisting of 100% Lee Ranch Coal, Gasifier @ 100% load, Shift @ normal End of Run (EOR); On-Peak operation @ 97°F Ambient
Design	The design duty of each chiller located in the AGR is provided by Linde. The total required duty is 20.1MW (68.65 MMBtu/hr).

iii) Feed Source

The AGR Refrigeration Unit is a closed loop system, sending liquid refrigerant to the AGR Unit and receiving vapor refrigerant from the AGR Unit.

The vapor refrigerant from the AGR is sent to a suction drum before entering the compressor. After compression, the gas is condensed, cooled, and the liquid refrigerant is returned to the AGR.

Table 3-29: Refrigerant Conditions

Components	Mol%	
Propylene	99.6	wt% min
Propane	0.4	wt% max
Oil content	10	ppmw max
Molecular Weight	42.09	
Temperature, °F	5.6	To AGR
Pressure, psia	223	To AGR
Temperature, °F	-30	From AGR
Pressure, psia	18.6	From AGR

B. Process Description

The vapor-compression refrigeration process is based on the auto-refrigeration effect caused by adiabatically flashing the liquid refrigerant. Liquid refrigerant is flashed upstream of the methanol chillers located in the AGR. The adiabatic flash lowers the refrigerant temperature which then cools the methanol. Refrigerant then returns to the AGR Refrigeration Unit and enters the suction traps. There are two 50% trains, both identical. The suction trap ensures only gas goes to the compressor. The gas is compressed and goes to the condenser where it is condensed using cooling water. An operating receiver downstream the condenser allows only liquid to go to the first subcooler. A portion of the stream going to the subcooler is removed and flashed. This flashed stream is used in the first subcooler to cool the remaining liquid refrigerant. The refrigerant that was flashed is sent back to an intermediate stage of the compressor. Liquid refrigerant leaves the first subcooler and enters the second subcooler. Again, a portion of the stream is removed and flashed for cooling the second subcooler. The refrigerant that was flashed is sent back to an intermediate stage of the compressor. The liquid refrigerant leaves the second subcooler and goes to the AGR.

The refrigerant level in each chiller is controlled by individual level control valves upstream the respective chiller. The valve will open up with an increased chiller duty and throttle down if the duty lessens. The refrigeration system will be initially charged with the required amount of refrigerant to meet the design duty. When the duty requirement is less, the discharge of the Compressor can be recycled. One compressor train can be shutdown if the duty requirement is reduced further.

Following are the descriptions of equipment within the AGR Refrigeration Unit.

i) Suction Trap

Vapor refrigerant from the AGR Unit enters the Suction Trap (032-PK-001-V-104A/B). Any liquid that may have condensed is removed in the Suction Trap to avoid damaging the compressor. The hot gas bypass from the discharge of the compressor is routed to the Suction Trap. The gas is introduced in the bottom of the vessel through 3 nozzles. A perforated plate distributes the gas evenly through the liquid. A liquid level of 10" is maintained by a level control valve on a liquid refrigerant line coming from downstream the HT Subcooler (032-PK-001-E-102A/B).

ii) Compressor

The Refrigerant Compressor, 032-PK-001-C-101A/B, is a 4 stage centrifugal compressor. The vapor refrigerant from the Suction Trap enters the first stage where it is compressed to about 39.6 psia. Vapor from the LT Subcooler (032-PK-001-E-103A/B), is combined with the first stage discharge before entering the second stage. The second stage compresses the gas

to about 73.4 psia. Vapor from the HT Subcooler (032-PK-001-E-102A/B), is combined with the second stage discharge before entering the third stage. The third stage compresses the gas to about 133.9 psia. The fourth stage compresses the gas to about 231.3 psia.

iii) Condenser

The Condenser (032-PK-001-E-101A/B) is a water cooled condenser. The gas from the Compressor is cooled to 100°F which is the saturation temperature of propylene at 227.3 psia. Cooling water enters at 80 °F and leaves at about 90 °F.

iv) Operating Receiver

Condensed refrigerant goes to the Operating Receiver (032-PK-001-V-101A/B). Liquid refrigerant is removed from the bottom of the vessel. The vapor space has an equalizing pressure line with the Condenser to maintain the pressure.

v) HT Subcooler

Liquid refrigerant from the Operating Receiver goes to the HT Subcooler where it is cooled from 100 °F to about 36.5 °F. A portion of the liquid coming from the Receiver is taken and flashed to about 77.3 psia. This flashed stream goes as a vapor/liquid mixture to the shell side of the subcooler. The gas from the subcooler goes to the 3rd stage of the Compressor.

vi) LT Subcooler

Liquid refrigerant from the HT Subcooler goes to the LT Subcooler where it is cooled from 36.5 °F to about 5.6 °F. A portion of the liquid coming from the HT Subcooler is taken and flashed to about 43.6 psia. This flashed stream goes as a vapor/liquid mixture to the shell side of the subcooler. The gas from the subcooler goes to the 2nd stage of the Compressor. An accumulator is located above the LT Subcooler to avoid any liquid carryover to the Compressor.

vii) Oil Distillers

The propylene needs to have less than 10ppmw oil to avoid diminished performance. There are two oil distillers per train. 032-PK-001-V-102A/B takes liquid from the bottom of both the HT Subcooler and LT Subcooler. A separate oil distiller (032-PK-001-V-103A/B), will take liquid from the bottom of the Suction Trap.

viii) Refrigerant Storage Vessel

The Refrigerant Storage Vessel is used to drain any single chiller located in the AGR or one of the compressor trains. Once the liquid has accumulated in the vessel, it is heated up to 130°F, to transfer the liquid to the Operating Receivers.

C. Operating Flexibility

i) Turndown

The AGR Refrigeration Unit is able to operate at 50% of design capacity.

ii) Sparing Philosophy

No equipment is spared.

iii) Reliability Issues

There is no known reliability issues associated with this system.

3.7.5 CO₂ Compression & Purification Unit

The CO₂ Compression and Purification Unit purifies Low Pressure (LP) and Medium Pressure (MP) CO₂ from the upstream Acid Gas Removal (AGR) Unit for urea synthesis or compression and transport via pipeline for enhanced oil recovery (EOR) and sequestration.

LP CO₂ has a higher initial purity than MP CO₂, so a portion of the LP CO₂ stream is first compressed to 430.5 psig and then purified to remove trace amounts of methanol, H₂S, and COS. This purified CO₂ is used for urea synthesis. The remaining LP CO₂ and all of the MP CO₂ are compressed to approximately 2,565 psig before it is injected into the ground for enhanced oil recovery.

A. Design Basis

i) Unit Capacity

The CO₂ Purification section is designed to produce around 135,500 lb/hr of purified CO₂ to support urea production. The EOR CO₂ Compression section is designed to handle the remainder of the CO₂, which ranges between 303,600 lb/hr and 764,100 lb/hr depending on the operating case.

ii) Design Cases

The design of the CO₂ Compression & Purification Unit is based on the following cases:

Table 3-30: Case Definition – CO₂ Compression & Purification Unit

Cases	Description
040-01	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100% load, Shift @ normal End of Run (EOR)
040-02	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 100% load, Shift @ normal Start of Run (SOR)
040-03	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 6 wt% sulfur, Gasifier @ 50% load, Shift @ normal Start of Run (SOR)
040-04	Gasifier feed consisting of 75% Lee Ranch Coal and 25% Petroleum Coke containing 1.16 wt% sulfur, Gasifier @ 50% load, Shift @ normal End of Run (EOR)
040-05	Gasifier feed consisting of 100% Lee Ranch Coal, Gasifier @ 100% load, Shift @ normal End of Run (EOR)

iii) Feed Source

The CO₂ Compression & Purification Unit receives LP and MP CO₂ from the AGR Unit.

Instrument air, cooling water, nitrogen, steam and other utilities are supplied by the OSBL units.

The LP CO₂ from the AGR Unit is sent through CO₂ purification where impurities such as methanol and sulfur compounds are removed from the CO₂ stream. The LP CO₂ is first compressed to about 430 psig by the CO₂ Purification Compressor (040-C-001) and then the compressed CO₂ subsequently goes through the Methanol Removal Reactor (040-R-001A/B) and COS/H₂S Removal Reactor (040-R-002) to remove the impurities.

The remaining LP CO₂ and MP CO₂ from the AGR unit serve as a feed for EOR. The EOR CO₂ Compressor (040-C-002) compresses the CO₂ to approximately 2,565 psig and the resulting fluid is supercritical CO₂.

iv) Product Specifications

1. High Purity CO₂

High purity CO₂ is produced as a result of the LP CO₂ purification through the Methanol Removal Reactor (040-R-001A/B) and the COS/H₂S Removal Reactor (040-R-002). The purified CO₂ is compressed before it is sent through the reactors to reduce the volume of catalyst required for the removal of the impurities. After the impurities are removed, the CO₂ is cooled down to at least 95 °F before it is sent to the urea synthesis unit. The purified CO₂ requirements are outlined in the table below.

Table 3-31: Purified CO₂ Product Conditions

Component	
Carbon Dioxide (CO ₂)	< 0.1 ppmv
Hydrogen Sulfide (H ₂ S)	< 0.1 ppmv
Total Sulfur (H ₂ S + COS)	< 0.3 ppmv
Methanol (CH ₃ OH)	< 200 ppmv
Molecular Weight	44.15
Temperature (°F)	95 (max)
Pressure (psia)	390 (min)

2. **Compressed CO₂ for EOR**

A significant portion of the carbon dioxide generated during steady-state operation is exported by pipeline to the nearby Elk Hills Field for EOR and Sequestration. A multi-stage centrifugal compressor is designed to deliver the CO₂ at a pressure of about 2,565 psig at the unit battery limit. LP CO₂ enters the compressor at the first stage of the compressor. MP CO₂ combines with the compressed LP CO₂ stream before entering the second stage of compression.

There are multiple interstage coolers. An aftercooler after the last stage of compression cools the supercritical CO₂ to around 110 °F. This allows for 10 °F heat gain due to solar radiation as the CO₂ flows through the pipeline. The requirements for the EOR CO₂ at the metering station located outside the unit battery limit are outlined below.

Table 3-32: EOR CO₂ Product Conditions

Component	Composition (Volume %)
Carbon Dioxide (CO ₂)	≥ 97%
Nitrogen (N ₂)	≤ 2%
Total Sulfur (H ₂ S & COS)	≤ 65 ppmv
Hydrocarbons (C1-C4), Argon and Hydrogen	≤ 1%
Hydrogen Sulfide (H ₂ S)	≤ 20 ppmv
Oxygen (O ₂)	≤ 10 ppmv
Sulfur Dioxide (SO ₂)	≤ 10 ppmv
Ammonia	≤ 1 ppmv
Particulate Matter (dust, sand, iron oxide, catalyst fines, silicates)	≤ 1 ppmv
Carbon Monoxide (CO)	≤ 1200 ppmv
Solvent (methanol)	≤ 400 ppmv
Water (H ₂ O)	0.61 lb/Mmcf 13 ppm (dew point 11 °F, no free water)
Temperature	120 °F (max)
Pressure	2,500 psig (min)

B. Process Description

i) EOR CO₂ Compressor and CO₂ Purification Compressor Suction Drums

LP CO₂ and MP CO₂ are fed to the CO₂ Compressors from the AGR unit. The LP CO₂ stream splits into two streams. One goes through the LP CO₂ Compressor Suction Drum (040-V-003) before going to the first stage of the EOR CO₂ Compressor (040-C-002); and the other LP CO₂ stream goes to the CO₂ Purification Compressor Suction Drum (040-V-001) for purification process. The MP CO₂ stream from the AGR unit goes to the MP CO₂ Compressor Suction Drum (040-V-002) before going to the second stage of the EOR CO₂ Compressor (040-C-002).

ii) EOR CO₂ Compressor

The EOR CO₂ Compressor (040-C-002) is a multi-stage integral gear centrifugal compressor. To improve performance and operating efficiency this machine is equipped with interstage coolers between stages and is provided with inlet guide vanes for capacity control.

LP CO₂ from the LP CO₂ Compressor Suction Drum (040-V-003) goes to the first stage of the EOR CO₂ Compressor (040-C-002) and is compressed up to approximately 22 psig. This CO₂ goes through an intercooler before combining with the MP CO₂ from the MP CO₂ Compressor Suction Drum (040-V-002) and entering the second stage of the EOR CO₂ Compressor (040-C-002).

The combined flow of CO₂ then goes through the remaining stages of compression for a final discharge pressure of about 2,575 psig and is finally cooled down to around 110 °F by the after cooler to meet the product temperature specification before it is sent to the pipeline for EOR.

iii) CO₂ Purification Compressor

A portion of the LP CO₂ stream from the AGR unit feeds the CO₂ Purification Compressor (040-C-001) via the CO₂ Purification Compressor Suction Drum (040-V-001). The CO₂ Purification Compressor (040-C-001) is a two stage centrifugal compressor. A butterfly valve is installed on the suction line of the compressor for capacity control.

The discharge of the first stage of the compressor goes to the CO₂ Purification Compressor Intercooler (040-E-001) where it is cooled to 105 °F before entering the second stage of the compressor. The discharge of the second stage of the CO₂ Purification Compressor (040-C-001) is approximately 430 psig and it goes to the CO₂ Purification Compressor After Cooler (040-E-002) where it is cooled to about 100 °F.

A portion of the stream leaving the CO₂ Purification Compressor After Cooler (040-E-002) is routed back to the suction of the CO₂ Purification Compressor (040-C-001) for surge control as needed. The remainder of the stream leaving the CO₂ Purification Compressor After Cooler (040-E-002) goes to the Methanol Removal Reactor (040-R-001A/B).

iv) Methanol Removal

Two 100% Methanol Removal Reactors (040-R-001A/B) operate at 100°F for optimal methanol adsorption to the catalysts. One reactor is in operation while the other one is in regeneration mode. The Methanol Removal Reactor (040-R-001A/B) reduces the methanol content in the CO₂ stream to less than 10 ppmv. The expected life of catalyst for the methanol removal catalysts is 2 years.

The compressed CO₂ leaving the CO₂ Purification Compressor After Cooler (040-E-002) enters the Methanol Removal Reactor (040-R-001A/B) from the top and flows downward through the reactor packing filled with catalysts. A methanol analyzer on the CO₂ outlet stream from the Methanol Removal Reactor (040-R-001A/B) continuously measures the methanol content and when it reaches 100 ppmv, the reactor in operation is isolated and put in regeneration mode. The process stream is then be rerouted to be processed by the other stand-by reactor.

v) Methanol Removal Catalyst Regeneration

When the methanol content in the CO₂ exit stream reaches 100 ppmv, the catalyst needs to undergo regeneration to restore the catalyst's effectiveness. The regeneration process occurs around 540°F and high pressure nitrogen is used as the regeneration medium.

High pressure nitrogen from the Air Separation Unit (ASU) is introduced to the system and the flow rate is regulated via flow control. The incoming high pressure nitrogen is heated up from 158 °F to 333 °F in the Nitrogen Cross Heat Exchanger (040-E-006) by the hot nitrogen stream exiting the Methanol Removal Reactor. It is further heated up to around 540 °F by the electric Nitrogen Heater (040-E-007) before it enters the Methanol Removal Reactor (040-R-001A/B) from the bottom. The hot nitrogen flows upwards through the reactor to regenerate the spent catalyst. The nitrogen exits the Methanol Removal Reactor (040-R-001A/B) from the top and is then cooled to approximately 364 °F by incoming nitrogen from the ASU in the Nitrogen Cross Heat Exchanger (040-E-006).

During the regeneration process, the Methanol Removal Reactor (040-R-001A/B) is depressurized and re-pressurized three times to ensure that no nitrogen remains in the reactor after regeneration. The depressurized gas is a mixture of CO₂ and nitrogen gas, and it is vented to the Gasification Flare.

vi) COS/H₂S Removal

The COS/H₂S Removal Reactor (040-R-002) operates at 375 °F to remove trace amounts of sulfur in the CO₂ stream. The sulfur removal catalyst is able to reduce the amount of H₂S and COS to less than 0.1 ppmv each in the product stream. The expected life of catalyst for the sulfur removal catalysts is 1 year.

Methanol-free CO₂ from the Methanol Removal Reactor (040-R-001A/B) is heated up in the COS/H₂S Reactor Feed Cross Heat Exchanger (040-E-003) by exchanging heat from the stream exiting the COS/H₂S Removal Reactor (040-R-002). The CO₂ is then further heated up to 375°F by the COS/H₂S Reactor Feed Heater (040-E-004) using Medium Pressure (MP) steam. The CO₂ enters the COS/H₂S Removal Reactor (040-R-002) from the top and flows downward through the reactor. The product stream exiting the reactor is cooled down in the COS/H₂S Reactor Feed Cross Heat Exchanger (040-E-003) by exchanging heat with the CO₂ stream leaving the Methanol Removal Reactor (040-R-001A/B). It is further cooled down by the CO₂ Purification Cooler (040-E-005) to at least 95°F by using cooling water to meet the product specification required for urea synthesis.

MP steam is condensed in the COS/H₂S Reactor Feed Heater (040-E-004) to heat up the CO₂ stream prior to entering the COS/H₂S Removal Reactor (040-R-002). The MP condensate from the COS/H₂S Reactor Feed Heater (040-E-004) is routed to the MP Condensate Flash Drum (040-V-004) to produce 60 psig LP steam. The LP steam and LP condensate generated by the MP Condensate Flash Drum (040-V-004) are routed to their respective headers.

C. Operating Flexibility

i) Sparing Philosophy

There are two 100% Methanol Removal Reactors with one in operation mode while the other is on stand-by/regeneration mode. Regeneration is expected to occur every 48 hours, and the reactors alternate being in operation and regeneration mode.

One COS/H₂S Removal Reactor is part of the unit without a spare.

One 100% two-stage centrifugal compressor with an interstage cooler and an after cooler is used for the purified CO₂ compression without a spare.

One 100% multi-stage centrifugal compressor with interstage coolers and an after cooler is part of the unit for the EOR CO₂ compression without a spare.

ii) Reliability Issues

There are no known reliability issues associated with this system.

3.7.6 Sulfur Plant

The Sulfur Plant consists of one Sulfur Recovery Unit (SRU) with a liquid sulfur degassing section and one Tail Gas Unit (TGU).

The SRU converts hydrogen sulfide (H_2S) in the acid/sour gas streams from the Acid Gas Removal (AGR) Unit and Gas Treating into elemental sulfur. The liquid degassing section of the SRU removes dissolved H_2S from recovered sulfur.

Tail gas from the SRU is processed in the TGU, where residual sulfur compounds are converted back to H_2S . The TGU also removes process water that is formed as a byproduct of the SRU Claus reaction. Converted tail gas is normally compressed and recycled to the Gas Treating Area.

A technical evaluation led to the selection of the Sulfur Group within Fluor Technology Corporation for their proprietary ammonia destruction technology and oxygen enrichment technology in the SRU, and their proprietary hydrogenation technology in the TGU. Goar, Allison, and Associates' (GAA) proprietary D'GAASS[®] technology was selected for the liquid degassing section of the SRU. Confidential Process Design Packages (PDPs) for the SRU, TGU, and sulfur degassing were prepared during FEED that applied these proprietary technologies to the HECA Project. Fluor's and GAA's sulfur plant processes are licensed technologies that are protected by NDAs. The system description that follows is a non-proprietary overview of the HECA Sulfur Plant.

A. Design Basis

i) Unit Capacity

The Sulfur Plant is nominally designed for 100 long tons per day (LTPD) of sulfur.

ii) Design Cases

The design of the Sulfur Plant is based on the six (6) cases outlined in Table 3-33.

Table 3-33: Case Definition – Sulfur Plant

Cases	Description
Design	Gasifier feed consisting of 75% Lee Ranch Coal (1.09 wt% sulfur) and 25% Petroleum Coke (6 wt% sulfur), Gasifier @ 100% load, Shift @ normal End of Run (EOR); normal case with adjustment of the acid gas for 20% additional CO ₂ content, plus additional CO ₂ to further reduce the H ₂ S concentration to 45 . An H ₂ S content of 45 vol% in the Rectisol acid gas represents both the Acid Gas Removal and the Sulfur Recovery Unit Licensors' minimum guarantee value.
050-01	Gasifier feed consisting of 75% Lee Ranch Coal (1.09 wt% sulfur) and 25% Petroleum Coke (6 wt% sulfur), Gasifier @ 100% load, Shift @ normal End of Run (EOR);
050-02	Gasifier feed consisting of 75% Lee Ranch Coal (1.09 wt% sulfur) and 25% Petroleum Coke (6 wt% sulfur), Gasifier @ 100% load, Shift @ normal Start of Run (SOR).
050-03	Gasifier feed consisting of 75% Lee Ranch Coal (1.09 wt% sulfur) and 25% Petroleum Coke (6 wt% sulfur), Gasifier @ 50% load, Shift @ normal Start of Run (SOR).
050-04	Gasifier feed consisting of 75% Lee Ranch Coal (1.09 wt% sulfur) and 25% Petroleum Coke (1.16 wt% sulfur), Gasifier @ 50% load, Shift @ normal End of Run (EOR).
050-05	Gasifier feed consisting of 100% Lee Ranch Coal (1.09 wt% sulfur), Gasifier @ 100% load, Shift @ normal End of Run (EOR).

iii) Feed Source

The SRU receives acid/sour gas feeds from the AGR Unit and Gas Treating's SWS and Ammonia Stripper.

The TGU processes tail gas and process water from the SRU.

50 wt% caustic is trucked in for use in the unit. With the exception of 600 psig steam, natural gas, BFW, steam, cooling water, nitrogen, and other utilities are supplied from the OSBL units.

iv) Product Specifications

1. Sulfur

The SRU produces a degassed commercial grade liquid sulfur product. The sulfur product quality specifications are listed in Table 3-34.

Table 3-34: Liquid Sulfur Product Quality

Quality	Commercial Grade Degassed Liquid Sulfur
Color	Bright Yellow
Purity	≥ 99.9 wt% (dry basis)
H ₂ S Content	≤10 ppmw
Moisture	≤ 500 ppmw
Carbon (Organic)	≤ 500 ppmw
Acidity (as H ₂ SO ₄)	≤ 10 ppmw

2. Compressed Tail Gas

TGU tail gas is normally compressed and recycled to the Shift Unit. There are no specifications on the compressed tail gas, except a battery limit pressure of at least 680 psig. Additionally, the temperature should be at least 25 °F above the sulfurous acid dew point, and that the composition shall be such that a continuance of the Claus reaction will not occur.

B. Process Description

i) SRU

The SRU consists of a Thermal Stage equipped with Fluor's proprietary Oxygen Enrichment Technology and Ammonia Destruction Technology, and two Claus Catalytic Reaction Stages.

a. Inlet (Acid Gas Wash and Sour Acid Gas KO Drums)

Acid gases from the upstream Acid Gas Removal (AGR) Unit enter the SRU via the Acid Gas Wash Drum. The drum has the capacity to handle liquid slugs from operating upsets within upstream units to protect the Reaction Furnace and catalyst in the Claus Converters from Rectisol solvent or hydrocarbon carryover. It is designed with a circulating water wash to remove contaminants (such as ammonia) which may be present in the acid gas feeds. Part of the Rectisol Acid Gas may be routed to the rear section of the Reaction Furnace during operation, where temperatures are not always sufficient to completely destroy ammonia, for example, and therefore it is important that contaminants be removed from the Rectisol Acid Gas stream before the gas is directed to the thermal stage. The Acid Gas Wash Drum Pump continuously recycles wash water to the drum. A small continuous stream of process water from the Desuperheater/Contact Condenser column is added to the wash water recycle stream, and an equally small slipstream purge containing the contaminants is discharged to the Sour Water Stripping Unit.

Sour Acid Gas from the header is routed to the Sour Acid Gas KO Drum. As with the Acid Gas Wash Drum, the Sour Acid KO drum has the capacity to handle liquid slugs from operating upsets within upstream units to protect the equipment in the SRU/TGU. Any liquid collected is pumped to the Sour Water Stripping Unit by the Sour Gas KO Drum Pump.

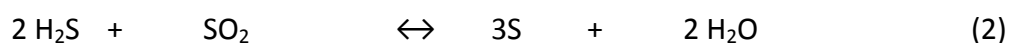
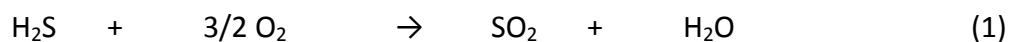
The SRU is operated on flow controls cascaded to the respective acid gases header pressures.

All the acid gases are preheated indirectly by 600 psig steam prior to entering the Main Burner via the Acid Gas Preheater and Sour Acid Gas Preheater, respectively.

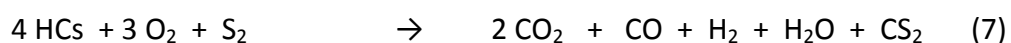
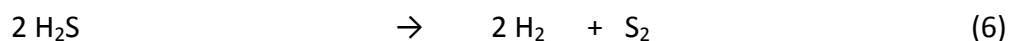
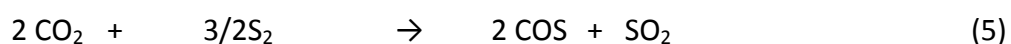
b. Claus Thermal Reaction Stage

Two electric-motor driven Combustion Air Blowers are provided to compress the air from atmosphere up to the required pressure for routing to the thermal reaction stage's Main Burners. In addition, an electric-motor driven Start-up Air Blower is provided to compress the additional combustion air required during SRU start-up mode and to serve as a backup to the Combustion Air Blowers. Vendor inquiries during the project's FEED phase indicate these machines might be positive displacement, rather the centrifugal type blowers.

Preheated acid and sour gases from the wash and KO drums, combustion air, and oxygen enter the SRU Claus Thermal Reaction Stage, which includes the Main Burner, the Reaction Furnace, Waste Heat Boiler (WHB) and No. 1 Sulfur Condenser. The acid gases are partially oxidized with oxygen and combustion air in the Reaction Furnace according to the basic chemistry of the Claus process, which is described by the following principal reactions:



Some side reactions, including those involving hydrocarbons (HCs) and CO₂ in the acid gas, are shown below:



c. Ammonia Destruction

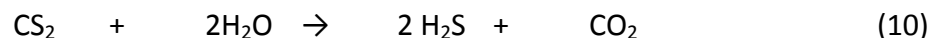
In order to ensure adequate destruction of NH₃ contained in the Sour Acid Gas, Fluor's proprietary Ammonia Destruction Technology is employed. The process maximizes the destruction of the ammonia present in the Sour Acid Gas under oxygen-deficient conditions. This technique minimizes problems associated with ammonia and ammonium salt formation in the colder parts of the SRU.

All the Sour Acid Gas, oxygen and combustion air are sent with a portion of the Rectisol Acid Gas to the Main Burner. The remainder of the Rectisol Acid Gas is routed to the back zone of the Reaction Furnace, bypassing the Main Burner. This partial bypass of Rectisol Acid Gas elevates the temperature in the front zone of the Reaction Furnace to about 2650 °F to 2800 °F, providing a sufficient temperature for ammonia destruction under a reducing environment.

The hot effluent gas from the Reaction Furnace is cooled in the WHB by generating 600 psig steam. The process gas is further cooled to below the sulfur dew point in the No. 1 Sulfur Condenser, which generates low pressure (LP) steam. The condensed sulfur drains to the Sulfur Rundown Pit via a mechanical (float type) sulfur trap (Sultrap).

d. Claus Catalytic Stages

In the first catalytic stage, the gas from the No. 1 Sulfur Condenser is heated indirectly in the No. 1 Reheater by 600 psig Steam and then enters the No. 1 Claus Converter, which contains both regular Claus and Titania Oxide (TiO₂) catalysts. In the catalytic stages, conversion of H₂S and SO₂ to sulfur takes place (8), in addition to hydrolysis of COS and CS₂ to H₂S (9, 10).



Conversion of H₂S and SO₂ to sulfur vapor in the catalyst bed is exothermic and results in a temperature increase across the catalyst bed. The converter effluent is cooled in the No. 2 Sulfur Condenser by generating LP steam. Condensed liquid sulfur drains to the Sulfur Rundown Pit via a mechanical sulfur trap (Sultrap).

The process is repeated in the second catalytic stage with the No. 2 Reheater and the No. 2 Claus Converter. The No. 3 Sulfur Condenser generates 15 psig steam, which is condensed via the Waste Steam Condenser. Operating the last sulfur condenser as a 15 psig steam generator rather than an LP steam generator allows for lower process gas

outlet temperature, thereby increasing Claus sulfur recovery.

Condensed liquid sulfur is separated from the gas in a coalescer section, which is integral with the No. 3 Sulfur Condenser and minimizes sulfur entrainment. The sulfur drains from the No. 3 Sulfur Condenser to the Sulfur Rundown Pit via a Sultrap.

e. Sulfur Rundown Pit and Sulfur Degassing

The SRU has a Sulfur Rundown Pit, in which rundown liquid sulfur from all three condensers is collected. The pit is equipped with internal LP steam coils to counteract heat losses in order to keep the collected sulfur molten.

The vapor space in the Sulfur Rundown Pit is swept with air to prevent buildup of an explosive concentration of H₂S, which desorbs from the collected Claus sulfur over time. The sweep air is supplied by a draft vent and is discharged to the Reaction Furnace through the Sulfur Rundown Pit Vent Ejector. The pit ejector uses medium pressure (MP) steam as a motive fluid. An alternate vent destination is provided to the Thermal Oxidizer so that it will not be necessary to evacuate the pit during SRU outages. A third destination, to be used only during upsets that include both the Reaction Furnace and Thermal Oxidizer non-operation, is provided to atmosphere through a natural draft chimney.

Liquid sulfur is pumped out of the Sulfur Rundown Pit by the Sulfur Degassing Feed Pump to sulfur degassing. The liquid sulfur is degassed to reduce the residual H₂S level in the product sulfur to 10 ppmw or less. Degassed sulfur is routed OBL to the Degassed Sulfur Storage Tank prior to final export loading. Vent gas from sulfur degassing is routed to the Reaction Furnace. An alternate degassing vent destination is provided to the Thermal Oxidizer.

The tail gas from No. 3 Sulfur Condenser is routed to the TGU. An analyzer measures the H₂S to SO₂ ratio of the tail gas, and adjusts the amount of oxidant feeding the Main Burner. This maintains the optimum oxygen supply and maximizes sulfur recovery.

f. Operation through Sulfur Condensers during Turndown

The Waste Heat Boiler and Sulfur Condensers are sized for the controlling Design Case feedstock. When operating at lower flows, such as during turndown, the reduced mass flux through the heat exchange train results in lowered heat-exchange coefficients. In some instances, this increases the temperature profile across the SRU train. Increased process gas temperature in the Claus Converters decreases the conversion of H₂S and SO₂ into elemental sulfur, hence decreasing the Claus sulfur recovery efficiency. In addition, the lower velocity through the exchangers increases the potential for corrosion

and/or fouling in the heat exchange trains. The duration of turndown operation (Cases 050-03 and 050-04) should be minimized.

ii) TGU

The TGU is configured with a Hydrogenation Section and a Tail Gas Compression Section which routes hydrogenated tail gas to the Shift Unit.

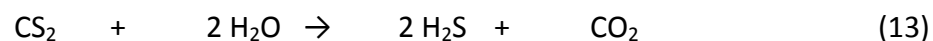
a. Hydrogenation Section

The tail gas hydrogenation section is required to convert almost all sulfur compounds in the SRU tail gas (SO₂, COS, CS₂ and elemental sulfur vapor) to H₂S. Hydrogenation is accomplished prior to compressing the tail gas for recycle to the Shift Unit. Conversion to H₂S minimizes the potential for plugging or corrosion issues en route to the Shift Unit, and also minimizes undesirable reactions in the Shift Unit. Tail gas from the No. 3 Sulfur Condenser is routed to the Tail Gas Heater, which indirectly heats the SRU tail gas using 600 psig steam.

The tail gas is further heated in the Tail Gas Trim Heater to the required temperature for the Hydrogenation Reactor. The Tail Gas Trim Heater uses electrical power as the source for heating.

The heated tail gas is then fed to the Hydrogenation Reactor, which is loaded with low-temperature Co-Mo catalyst in order to reduce sulfur species to hydrogen sulfide.

Hydrogenation and hydrolysis reactions for the four primary sulfur constituents are as follows:



Treated syngas is available to supplement the tail gas to provide the required hydrogen necessary for reactions (11) and (12) above. However, normally no hydrogen make-up is required as sufficient hydrogen is already present in the SRU tail gas. An analyzer on the overhead of the Desuperheater/Contact Condenser is used to verify that a sufficient excess of hydrogen is present for reactions (11) and (12) to proceed to completion in the Hydrogenation Reactor.

The gas exiting from the reactor is cooled by generating LP steam in the Reactor Effluent Cooler. The outlet gas from the Reactor Effluent Cooler must be further cooled down to allow removal of water and to reach a temperature at which the downstream compressor can function.

b. Direct Contact Condensing Section

The Desuperheater/Contact Condenser (DCC) features a two-pumparound loop design. The bottom pumparound loop serves two functions: 1) desuperheats the tail gas via a circulating stream of dilute caustic, and, 2) provides a degree of protection against SO₂ break through to the Shift Unit.

Outlet gas from the Reactor Effluent Cooler is first desuperheated in the lower section of the DCC column by contacting with a bottom pumparound stream of weak caustic solution that is circulated over baffle trays by the Desuperheater Pump. This stream is maintained alkaline at a pH above 9 to protect against any SO₂ breakthrough from the reactor by periodically charging with a caustic solution. Caustic can be added as required to maintain the pH. A pH less than 9 is an indication the caustic in the DCC should be changed out. Under normal operating conditions, no injection is required as essentially no SO₂ is present downstream of the Hydrogenation Reactor.

Part of the bottom pumparound is vaporized as it contacts and desuperheats the incoming hot gas. In order to compensate for the vaporization loss and to maintain level in the bottom of the DCC column, water is made up to the lower section from the upper section's Contact Condenser Pump.

The upper pumparound accomplishes the bulk cooling of the process gas. The Contact Condenser Pump circulates water from the chimney tray through the Contact Condenser Cooler, which uses cooling water to cool the pumparound process water. This cooled pumparound water is returned to the top of the column's packed section. The contacting of the still-warm gas from the lower section with the cold upper pumparound water cools the gas and condenses much of the water vapor contained in the tail gas. The gas volume leaving the DCC is lower than, and much cooler than, the inlet gas. Thus, the volume of gas entering the downstream compressor is reduced and the gas is at an adequate temperature for compression. The upper pumparound loop includes a process water (slightly sour) bleed flow under level control of the chimney tray liquid level.

During start-up, there may be too low a volumetric flow of tail gas being generated in the SRU to satisfy the minimum volumetric flow rate needed in the TGU. The minimum TGU volumetric flow rate is typically about one-third of the design flow rate (or higher). For this reason, tail gas can be recycled from the overhead of the DCC column, through

the Tail Gas Heater, Hydrogenation Reactor and Reactor Effluent Cooler, and back to the DCC column. In this manner, the TGU can achieve satisfactory operation while the SRU throughput is being ramped up to design flow rate.

A TGU Start-up Ejector located upstream of the DCC column is used to assist in start-up of the TGU. The ejector uses MP steam as a motive fluid to generate sufficient discharge pressure so that nitrogen and/or tail gas may be recycled through the TGU.

c. Tail Gas Compression Section

The Desuperheater/Contact Condenser overhead gas is routed to a Tail Gas Compressor. The compressor is expected to be a multi-stage, integrally geared compressor, with suction and interstage knock-out drums, and interstage cooling. The final stage may also require a spill-back and spill-back cooler for proper control and/or anti-surge protection. The preliminary design prepared during FEED must be confirmed during detailed engineering after vendor selection. Per the Design Basis sparing philosophy, a complete 100% spare compressor with all associated interstage, pre-compressor and post-compressor items is provided.

d. Thermal Oxidizer and Stack

A forced draft Thermal Oxidizer is provided for the SRU/TGU. The purpose of the Thermal Oxidizer is to convert hydrogen sulfide and other sulfur species to sulfur dioxide. Oxidized tail gas is discharged to atmosphere through a Stack. Combustion air is supplied by the Thermal Oxidizer Air Blowers. A preliminary design for the Thermal Oxidizer and associated combustion air and fuel controls was prepared during FEED. This design included staged air (primary, secondary and tertiary) in order to minimize NO_x emissions. The Thermal Oxidizer design must be confirmed during detailed engineering after vendor selection.

The Thermal Oxidizer normally operates in hot-standby mode, firing on Natural gas and Combustion air only – no process related streams are directed to the Thermal Oxidizer during normal operation. Thermal oxidation of process streams should only occur for a period long enough to assist with startup of SRU, restart of the TGU or Tail Gas Compressor, or to facilitate an orderly shutdown of the SRU-TGU if a restart cannot be achieved in a reasonable duration. For example, vent gases from sulfur degassing and the Sulfur Rundown Pit are routed to the Thermal Oxidizer as an alternate vent destination if the SRU goes off-line. Several bypass streams may also be routed to the Thermal Oxidizer during upsets:

Hydrogenated tail gas may be routed to the Thermal Oxidizer during a Tail Gas Compressor shutdown.

SRU tail gas from the final sulfur condenser may be routed to the Thermal oxidizer during an upset in the TGU. Additionally, during initial startup of the SRU, tail gas from the final sulfur condenser may be routed to the Thermal Oxidizer.

The Thermal Oxidizer will be fired with Natural gas and air. Typically 2%-3% excess oxygen in the effluent stream is targeted, along with an effluent gas temperature of between 1200 to 1500°F needed to adequately oxidize the compounds found in the vent gases or bypass streams, particularly H₂S (converting to SO₂). Target combustion temperature is to be finalized by the detailed engineering contractor in conjunction with the selected equipment vendor. Hot standby temperature should also be established in conjunction with the Thermal Oxidizer vendor during detailed engineering. The standby temperature should be as low as possible while still maintaining the ability to safely and reliably accommodate rapid increase up to full operating condition.

iii) H₂S Scrubbing

When the SRU is shutdown or during start-up of the AGR, an H₂S Scrubbing system is required to treat the Rectisol Acid gas prior to flaring, so that the gasifier can continue to run without violating permitted sulfur emissions. The H₂S Scrubbing system is therefore required to be in stand-by mode continuously, even when the AGR and SRU are operating normally.

During stand-by operation, the Caustic Circulation Pump continuously circulates a small stream of 15 wt% caustic over the H₂S Scrubber to maintain liquid on the trays.

When the Rectisol Acid Gas is diverted to the Caustic Scrubber, the H₂S Scrubber Pump automatically starts and circulates enough caustic over the H₂S Scrubber to absorb all the H₂S. The caustic also co-absorbs CO₂. Sour gases will not be caustic scrubbed or flared should the SRU shut down. Instead, sour water stripping will be curtailed and sour water will be held up in a tank until the SRU comes back on.

When H₂S breakthrough is detected in the vapor outlet from the H₂S Scrubber, the Fresh Caustic Pump automatically feeds fresh caustic from the Fresh Caustic Tank to the H₂S Scrubber. The amount of caustic stored in the Fresh Caustic Tank allows the H₂S Scrubber to operate for an additional 4 to 5 hours if necessary.

iv) Caustic Handling

The H₂S Scrubber utilizes caustic solution which reacts with the H₂S to produce various salts. Although it is not required or desired, caustic also reacts with the CO₂ in the Acid Gas stream which increases caustic consumption. Below is a list of the salts produced from the reaction between the Acid Gas and caustic:

- Salts Produced with H_2S : Na_2S ; NaSH
- Salts Produced with CO_2 : Na_2CO_3 ; NaHCO_3

Na_2CO_3 hydrates can crystallize out of solution if the spent caustic temperature drops to between 40 °F and 70 °F. Therefore, spent caustic should not be stored in the tank for excessive time periods, particularly in cooler weather.

A 15 wt% concentration for caustic was chosen since the heat of reaction between H_2S and CO_2 and caustic can heat the solution sufficiently so that it boils at higher concentrations. The maximum temperature attained in the H_2S Scrubber's design case is 193 °F, which is below the boiling temperature of the 15 wt% caustic at atmospheric pressure.

50 wt% caustic is trucked in and diluted to 15 wt% with demineralized water in the Fresh Caustic Tank.

The tank has provision for in-line dilution or in-tank dilution. Dilution of caustic results in an increase in solution temperature - as such, caustic solution should be added after the dilution water is flowing or a reserve volume in the tank is established. Also, the dilution water should be temperate – on the order of 80 °F – 100 °F to keep the diluted caustic temperature within acceptable limits (70 °F < dilution temp < 145 °F).

In-tank dilution is accomplished by adding a predetermined volume of demineralized water to the Fresh Caustic Tank as defined by a certain level, or level change, in the tank equivalent to that required to dilute a tank truck load of 50 wt% caustic to 15 wt%. The Fresh Caustic Pump is started in recirculation mode to the Caustic Solution Jet Mixers inside the tank. 50 wt% caustic is added to the tank directly from the tanker truck after the tank is first filled with the required, corresponding amount of water.

In-line dilution is accomplished by first starting the demineralized water flow and then adding in the 50 wt% caustic by ratio control. The two components combine in-line by means of a static mixer. The tanker truck is pressurized with plant air to provide a differential pressure between it and the storage tank. It is assumed that the truck comes equipped with the devices necessary for proper, safe operation, such as an air filter, air pressure regulator, and tanker relief valve.

Spent caustic produced in the H_2S Scrubber and the Desuperheater/Contact Condenser is removed in a batch operation. From the H_2S Scrubber, spent caustic solution is automatically sent directly to the Spent Caustic Tank using a slip-stream off the H_2S Scrubber Pump. From the Desuperheater/Contact Condenser, spent caustic is manually directed to the Spent Caustic Tank.

Spent caustic from either producer is cooled to 140 °F before entering the Spent Caustic Tank. Spent caustic is removed from the tank with the Spent Caustic Loading Pump and loaded into tank trucks where it is taken offsite.

v) 600 psig Steam

The pressure of the facility's high pressure (HP) steam is too high for the Sulfur Plant. The 600 psig steam level was chosen because corresponding temperature is high enough to provide adequate heating where needed throughout the Sulfur Plant. It also provides adequate waste heat cooling of the Reaction Furnace effluent gases. Moreover, the 600 psig steam allows for acceptable stresses on the WHB flexible tubesheet as well as relatively low cost carbon steel construction.

During normal operations, 600 psig steam is generated by exchanging heat with the process gas exiting the Reaction Furnace and is consumed by various steam heaters throughout the SRU and TGU. Because there is no 600 psig steam network outside of the Sulfur Plant battery limits, the pressure is maintained on back-pressure control within the Sulfur Plant. More 600 psig steam is generated than is consumed during normal operations. The surplus is let down to the OSBL MP steam main header.

During startup and hot standby operations, when no or insufficient 600 psig steam is generated from within the Sulfur Plant, MP steam from the OSBL main header will be backed in to the 600 psig steam header to support initial heating of the SRU/TGU.

C. Operating Flexibility

i) Turndown

The unit is designed for turndown operation as defined in Cases 050-03 & 050-04.

ii) Equipment Design Factors

The unit is designed for 100% of capacity, with the exception of the sulfur degassing equipment. The sulfur degassing equipment is designed for 135 LTPD of undegassed feed sulfur to allow the SRU to operate for a short period while the degassing section is offline.

iii) Sparing Philosophy

A common spare pump is provided for the similar desuperheater and contact condenser pump services. All other continuous service pumps are provided with a dedicated, installed spare. Intermittent service pumps are provided with warehouse spares.

Two Combustion Air Blowers and one Start-up Air Blower are provided. All three of these blowers are electric-motor-driven. For most operating cases, one combustion air blower will be operating, and the second serves as an installed spare. For Case 050-05, two combustion air blowers may be operating (depending on oxygen-enrichment level selected) and the Start-up Air Blower serves as a spare for both. During start-up, all three blowers will operate to supply start-up combustion air.

Three 50% Thermal Oxidizer Air Blowers are provided to satisfy the various operating requirements for air to the Thermal Oxidizer.

iv) Reliability Issues

There are no known reliability issues associated with this system.

3.7.7 PSA & Off-Gas Compression

The pressure swing adsorption (PSA) & Off-Gas Compression Unit is required to produce ultra-pure hydrogen for ammonia production.

The feed gas to the PSA Unit is clean syngas from the Acid Gas Removal (AGR) Unit. The molecular sieve in the PSA Unit selectively adsorbs the impurities in the syngas feed at the feed pressure. These impurities are desorbed by “swinging” the adsorber pressure from the feed pressure to the off gas pressure and by using a high-purity purge. The hydrogen is not adsorbed and is recovered at high purity.

The PSA Unit consists of two PSA packages in series to achieve overall hydrogen recovery of at least 94%. Multiple adsorbers are operated in a staggered sequence to maintain constant feed, product, and off-gas flows. The off-gas from the first PSA package (PSA Package #1) is compressed and fed to the second PSA package (PSA Package #2) which produces additional high purity hydrogen. Recovered pure hydrogen is routed to the Ammonia Synthesis Unit.

The current design is based on sending the off-gas from PSA Package #2 to the duct firing section of the Power Block. It was later determined that potential suppliers for the Power Block HRSG duct burners would not guarantee emissions for the PSA off-gas at levels stated in the air permit application. Therefore, the design would need to be modified during a subsequent phase of engineering such that the PSA off-gas is compressed to about 500 psig and blended with the main treated syngas stream flowing to the Power Block. PSA #2 Off-Gas Compressor would need to be modified to discharge at the new, higher pressure.

A. Design Basis

i) Unit Capacity

The PSA & Off-Gas Compression Unit is designed to produce hydrogen with a minimum purity of 99.90 mol%, to meet the target product slate.

During normal “on-peak” operation, the unit is designed to produce 9,203 lbmol/hr of hydrogen at about 489 psig/101 °F for the Ammonia Synthesis Unit. During normal “off-peak” operation, the unit is designed to produce 15,337 lbmol/hr of hydrogen at about 488 psig/114 °F for the Ammonia Synthesis Unit.

ii) Design Cases

The design of the PSA & Off-Gas Compression Unit is based on the cases described in the table below.

Table 3-35: Case Definition – PSA & Off-Gas Compression Unit

Cases	Description
060-01	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); On-peak operation @ 97°F Ambient
060-02	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); Off-peak operation @ 97°F Ambient
060-03	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); On-peak operation @ 65°F Ambient
060-04	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); Off-peak operation @ 65°F Ambient
060-05	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); On-peak operation @ 39°F Ambient
060-06	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); Off-peak operation @ 39°F Ambient
060-07	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal Start of Run (SOR); On-peak operation @ 97°F Ambient
060-08	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 100% load, Shift @ normal Start of Run (SOR); Off-peak operation @ 97°F Ambient
060-09	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 50% load, Shift @ normal Start of Run (SOR); @ 97°F Ambient
060-10	Gasifier feed consisting of 75% Lee Ranch coal and 25% Petroleum Coke containing 6 wt% Sulfur; Gasifier operating @ 50% load, Shift @ normal End of Run (EOR); @ 97 °F Ambient
060-11	Gasifier feed consisting of 100% Lee Ranch coal; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); On-peak operation @ 97 °F Ambient
060-12	Gasifier feed consisting of 100% Lee Ranch coal; Gasifier operating @ 100% load, Shift @ normal End of Run (EOR); Off-peak operation @ 97 °F Ambient

iii) Feed Source

The PSA & Off-Gas Compression Unit receives clean syngas from the AGR Unit.

Instrument air, cooling water, nitrogen, steam and other utilities are supplied by the OSBL units.

iv) Product Specifications

1. High Purity Hydrogen

High purity hydrogen is recovered from the PSA as a product and sent to the Ammonia Synthesis Unit. Due to the product purity requirements listed in the below table, the proposed hydrogen recovery by the vendor is 94%.

Table 3-36: Hydrogen Product Conditions (Outlet of PSA #1 and PSA #2)

Composition, mol %	
H ₂	99.90 mol% minimum
N ₂	0.10 mol% maximum
CO	5 ppmv maximum
CO ₂	- -
Water	- -
Ar	65 ppmv maximum
CH ₄	0.1 ppmv maximum
H ₂ S	(Note 1)
Molecular Weight	2.04
Temperature, °F	101
Pressure, psia	484

Notes:

(1) Total sulfur in the synthesis make-up gas is no more than 0.1 ppmv.

2. Off-Gas

The off-gas from the PSA Package #1 is sent to the inlet of the PSA #1 Off-Gas Compressor (060-C-001). The off-gas is compressed from 5 psig to about 502 psig by the four stage compressor and cooled to about 104°F before being fed to the PSA Package #2 for further hydrogen recovery. There are three interstage coolers that cool the compressed gas after each stage to about 105°F before being fed for further compression.

The off-gas from the PSA Package #2 is sent to the inlet of the PSA #2 Off-Gas Compressor (060-C-002) which compresses the off-gas from 5 psig to about 60 psig and delivers the off-gas to the Power Block HRSG at about 429°F for duct firing.

B. Process Description

i) General

The pressure swing adsorption process is based on physical adsorption phenomena, whereby highly volatile compounds with low polarity, as represented by hydrogen or helium, are practically non-adsorbable compared to molecules such as CO₂, CO, N₂ and hydrocarbons. Hence, most impurities in hydrogen containing streams can be selectively adsorbed and high purity hydrogen is obtainable.

The pressure swing adsorption process is working between two pressure levels:

- 1) Adsorption of impurities is carried out at high pressure to increase the partial pressure and therefore, the loading of the impurities on the adsorbent material.
- 2) Desorption or regeneration takes place at low pressure to reduce the residual loading of the impurities as much as possible in order to achieve high product purity, high delta loading adsorption/desorption and subsequently a high hydrogen recovery.

The process works at ambient temperature. There is no heat required for regeneration. Changes in temperature are caused only by heat of adsorption, desorption, and depressurization. This feature results in an extremely long lifetime of the adsorbent material as no hydrothermal effect will deactivate the adsorbent.

The feed gas flows through the adsorbers in an upward direction. The impurities such as water vapor, light & heavy hydrocarbons, CO, and nitrogen are selectively adsorbed from bottom to the top. High purity hydrogen flows from the top to the product line.

The adsorbers are on staggered cycles resulting in a highly flexible purification unit which is not influenced by fluctuations of the composition, temperature and pressure of the feed gas. The system allows a high performance by maximum utilization of the hydrogen stored in an adsorber at the end of adsorption for pressure equalization, repressurization, and purging of other adsorbers.

After the adsorption step, the adsorber is regenerated in four basic steps:

- 1) The adsorber is depressurized to a low pressure level co-current to the feed flow. The co-current depressurization uses the hydrogen stored in the adsorber to repressurize and purge other adsorbers.
- 2) The adsorber is depressurized in the counter-current direction to off-gas pressure (blowdown step) to remove the impurities from the adsorbent.
- 3) The adsorber is purged at off-gas pressure with pure hydrogen to desorb the residual impurities from the adsorbent.
- 4) The adsorber is repressurized to adsorption pressure with pure hydrogen coming from adsorbers on the depressurization step.

In order to recover most of the hydrogen stored in an adsorber at the end of the adsorption step, several pressure equalizations are performed.

ii) Knockout Drum

Clean syngas is fed to the PSA from the AGR Unit. It enters 060-V-001, PSA #1 Feed KO Drum, which is designed to remove the methanol droplets (if any) from the feed gas stream. The liquid in the drum (if any) is free drained to a portable drum, while the H₂ and other gases are sent to the PSA Package #1 (060-PK-001).

iii) PSA Package #1 (060-PK-001)

The PSA Package #1 (060-PK-001) is designed to recover 87.5% of the incoming H₂. It includes twelve (12) adsorbers, a pair of hydrogen product filters, a pair of off-gas filters, and up to two off-gas drums.

Feed gas flows up through the adsorption columns and high purity H₂ comes out the top. The high purity H₂ goes to the H₂ Gas Filters (060-PK-001-F-101 A/B), which are two 100% filters. The off-gas from the adsorbers goes to the PSA #1 Off-Gas Surge Drum (060-PK-001-V-113) and then to the PSA #1 Off-gas Filters (060-F-001 A/B), which are two 100% filters. Both sets of filters remove 99% of particles 5 microns and larger from the streams, including line scale and adsorbent fines.

iv) Off-Gas Compression

After the off-gas passes through 060-F-001 A/B, it is sent to a multi-stage compressor (060-C-001). After each stage, the off-gas goes through an interstage cooler which cools the off-gas to about 105 °F. The gas is compressed in the first stage and flows through 060-E-001, PSA #1 Off-Gas Compressor Intercooler #1, and then into 060-V-002, the PSA #1 Off-gas Compressor First Interstage KO Drum. At this stage, operating pressure on the cooling water side of 060-E-001 is greater than the pressure on the gas side. A potential tube leak would cause water to leak into the gas stream. Any liquid from the PSA #1 Off-gas Compressor First Interstage KO Drum drains to the Oily Water Sewer system.

The off-gas is further compressed in the second, third, and fourth stages. PSA #1 Off-gas Compressor Intercooler #2 and #3, 060-E-002 and 060-E-003, cool the compressed gas between stages and 060-E-004, the PSA #1 Off-gas Aftercooler, cools the fourth stage discharge to about 104 °F before it goes to the PSA Package #2.

v) PSA Package #2 (060-PK-002)

The PSA Package #2 (060-PK-002) is designed to recover 52% of the incoming H₂. It includes ten (10) adsorbers, a pair of hydrogen product filters, a pair of off-gas filters, and one off-gas drum.

Off-gas flows up through the adsorption columns and high purity H₂ comes out the top. The high purity H₂ goes to the H₂ Gas Filters (060-PK-002-F-101 A/B), which are two 100% filters. The off-gas from the adsorbers goes to the PSA #2 Off-gas Surge Drum (060-PK-002-V-111) and then to the PSA #2 Off-gas Filters (060-F-002 A/B), which are two 100% filters. Both sets of filters remove 99% of particles 5 microns and larger from the streams, including line scale and adsorbent fines.

vi) Hydrogen Product

Hydrogen recovered from top of adsorbers in the PSA Package #1 passes through H₂ Gas Filters, 060-PK-001-F-101 A/B. This stream combines with the other Hydrogen stream recovered from PSA Package #2 which also passes through other set of H₂ Gas filters, 060-PK-002-F-101 A/B. The combined hydrogen-rich stream is sent to the Ammonia Synthesis Unit.

vii) Off-Gas

Off-gas from the PSA Package #2 is compressed by 060-C-002, PSA #2 Off-gas Compressor, and sent out of the unit for duct firing. The compressor has one stage with a spillback line for operation flexibility. The spillback stream passes through 060-E-005, the PSA #2 Off-gas

Compressor Spillback Cooler, to cool the recycle gas before it is fed back to the compressor suction.

C. Operating Flexibility

i) Turndown

The unit is able to operate at constant H₂ recovery rate and product purity at 50% to 100% of design capacity.

ii) Sparing Philosophy

All adsorbers are used in normal operation. Taking columns out of operation will decrease the unit hydrogen production.

One 100% centrifugal compressor (four stage), three interstage coolers, knockout drum, and one after cooler are integral part of the unit design for the PSA #1 off-gas compression without spares.

One 100% centrifugal compressor (one stage) and spillback cooler are included in the unit for the PSA #2 off-gas compression without spares.

iii) Reliability Issues

There are no known reliability issues associated with this system.

3.7.8 Power Block

The combined cycle Power Block includes a Combustion Turbine, a Steam Turbine, a hydrogen cooled Generator, a Heat Recovery Steam Generator (HRSG), a water-cooled Surface Condenser, and ancillary equipment / systems. The Combustion Turbine, Steam Turbine, and Generator are on a single shaft configuration as designed by Mitsubishi Heavy Industries.

The Power Block generates power to supply electricity to the grid and to service plant auxiliary loads. The Power Block also distributes boiler feedwater (BFW) through the Plant and collects and distributes steam at various pressure levels for Plant use.

There are three separate units in the Power Block:

- Combustion Turbine / Steam Turbine / Generator (CT/ST/G), which also includes the steam distribution system
- Heat Recovery Steam Generator (HRSG)
- Balance of Power Block / BFW / Low & High Temperature Flue Gas Ducting

During FEED, the design was based on two separate duct burners in the HRSG. One duct burner was intended to consume excess hydrogen-rich fuel (syngas), and the other duct burner was intended to consume PSA off-gas and ammonia vent gas. Inquiries made to potential duct burner suppliers revealed that these suppliers would not guarantee emissions for the PSA off-gas and ammonia vent gas at levels stated in the Air Permit application. During detailed engineering, the design will need to be modified such that the PSA off-gas and ammonia vent gas are compressed and blended with the main syngas stream flowing to the power block. This would require a single duct burner to burn excess blended fuel during on-peak operations and be turned off during off-peak operation.

This section provides a description of the Power Block with the dual HRSG duct burner FEED configuration.

A. Design Basis

i) Unit Capacity

The Power Block's gross power generation is a nominal 420 MW during "On Peak" operations.

ii) Design Cases

The Plant design accommodates both the “On-Peak” case for maximum power production with lower ammonia production and the “Off-Peak” case for maximum ammonia production with lower power production. The On-Peak Case maximizes the output from the Power Block and limits the Ammonia Plant production to about 60% of full production. During the Off-Peak Case, the Power Block operates at roughly 65% and while the Ammonia Plant operates at full capacity.

The fuel flow rates and compositions change from SOR to EOR operations. During SOR, when the Shift Unit catalyst is more active, the treated syngas flow to the Power Block is greater and with higher heating content. During EOR, when the Shift Unit catalyst is less active, the treated syngas flow is lower and with lower heat content. However, the PSA off-gas flow to the duct burners is higher and with more heating value during the EOR case than SOR. The net effect is slightly higher power production during EOR operation (from higher PSA duct burning) than SOR operation for On-Peak Cases while SOR operation produces more power for Off-Peak Cases (from higher syngas energy).

The Power Block has six (6) main performance cases for On-Peak and Off-Peak Cases across the ambient temperatures of 97 °F, 39 °F, and 65 °F using the EOR conditions. The cases are described in the table below.

Table 3-37: Case Definition – Power Block

<u>Case 1</u>	<u>Case 2</u>	<u>Case 3</u>	<u>Case 4</u>	<u>Case 5</u>	<u>Case 6</u>
97 Degrees		39 Degrees		65 Degrees	
On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak

iii) Feed Source

After the syngas treatment in Acid Gas Removal (AGR), the hydrogen-rich fuel is split and distributed to the Fertilizer Complex for production of saleable products and to the Power Block for power production.

PSA off-gas from PSA & Off-Gas Compression and ammonia vent gas from the Fertilizer Complex are blended before feeding the Power Block HRSG duct burners.

B. Process Description

i) Combustion Turbine / Steam Turbine / Generator

a. Combustion Turbine

The Combustion Turbine is a Mitsubishi Heavy Industries (MHI) M501 GAC machine. It is capable of consuming hydrogen-rich fuel (syngas) or natural gas, with the primary fuel being syngas from the AGR. The Combustion Turbine requires nitrogen when firing on syngas to minimize the NO_x formation by reducing the flame temperature. Using the Evaporative Cooling System while operating “on-peak” during warm ambient temperatures boosts the output of the Combustion Turbine.

The Combustion Turbine will operate on natural gas when Gasification is off-line, producing up to 80% of its syngas rating when firing on natural gas. During periods of natural gas operation, the Combustion Turbine requires demineralized water injection for NO_x control. It is noted that the Air Permit may impose a limitation on natural gas operation, not including start-up and shut-downs.

Other Combustion Turbine ancillary systems include the inlet air filters and housing, lube oil system, control oil system, fire protection system, washing and drain system, and the Turbine Cooling Air (TCA) system.

b. Steam Turbine

The Steam Turbine is supplied Mitsubishi Heavy Industries (MHI). It is a single casing machine with a reheat section and a single axial flow exhaust to the Surface Condenser. It shares the same lube oil system and the control oil system as provided with the Combustion Turbine. The Steam Turbine’s ancillary equipment includes the Gland Steam Condenser and the vacuum breaker.

The Power Block integrates the high-high pressure (HHP) steam produced by Gasification’s Waste Heat Boiler into the HRSG and Steam Turbine design. The HHP steam is let down into the cold reheat (CRH) steam header.

c. Generator

The Generator is a hydrogen cooled power generator located between the Combustion Turbine and Steam Turbine. A hydraulic clutch between the Steam Turbine and the Generator allows the Combustion Turbine to startup before introducing steam.

d. Steam Distribution System

The Steam Distribution System connects all of the Plant's steam producers with the steam consumers. This system has the flexibility of routing excess steam into the Surface Condenser within the limits of the Surface Condenser and the Power Block Cooling Tower capacities. The HECA facility has several steam levels as described below.

- Ultra High Pressure (UHP) Steam: The UHP steam is specific to the Power Block. The HRSG's UHP Steam Drum is the only generator of UHP steam and the Steam Turbine is the main consumer.
- High-High Pressure (HHP) Steam: The sole source of the HHP steam comes from the Waste Heat Boiler in Gasification. This steam goes directly into the HP steam header for process usage. Any excess HHP steam not utilized by the process users goes into the cold reheat (CRH) steam header.
- High Pressure (HP) Steam: The Plant has two sources of HP steam: 1) the superheated HP steam produced by the HHP-to-HP letdown station; and 2) the saturated HP steam generated by the Fertilizer Complex. During normal operation, the HHP-to-HP letdown station is the main source of superheated HP steam while the Auxiliary Boiler supplements the required superheated HP steam during Plant startups. The Shift Unit is the only consumer of HP steam and it controls the superheated and saturated HP steam blending per its operating requirements.
- Medium Pressure (MP) Steam: The HP-to-MP letdown station is the primary source of MP steam to the process users. Secondary sources include the HP steam letdown from the SRU and the Fertilizer Plant. The HRSG also generates MP steam which combines with CRH steam from the Steam Turbine for additional power generation. During natural gas operation, there will be a shortage of LLP steam to operate the Deaerator. In this case, saturated steam from the MP Steam Drum provides pegging steam to the Deaerator.
- Cold Reheat (CRH) and Hot Reheat (HRH) Steam: The reheat steam is specific to the Power Block which comes from the Steam Turbine's HP section exhaust. This CRH steam combines with excess HHP steam from Gasification and the steam generated by the HRSG's MP steam section before flowing through the reheat coils in the HRSG to regain superheat. This HRH steam returns to the Steam Turbine, thus greatly increasing the efficiency of the Steam Turbine.
- Low Pressure (LP) Steam: The Shift Unit is the primary producer of LP steam with the Fertilizer Complex, the SRU, and CO₂ Purification as secondary sources. The AGR is the major LP steam consumer with other users being the Waste Water

Treatment Plant, the Sulfur Loading Area, and Gasification. The HRSG superheats the remaining LP steam for Steam Turbine consumption for additional power production.

- Low-Low Pressure (LLP) Steam: The Shift Unit is the only LLP steam producer and used in the Deaerator's stripping section. The Surface Condenser can condense excess LLP steam to prevent venting steam into the atmosphere, thus conserving demineralized makeup water.

With a multi-pressure steam system, there are several steam letdowns where a higher pressure steam supports a lower pressure steam header. The HECA Project has the following steam letdown stations:

- UHP Steam Letdown to HP Steam
- HHP Steam Letdown to HP Steam
- HHP Steam Letdown to CRH Steam
- HP Steam Letdown to MP Steam
- MP Steam Letdown to LP Steam
- LP Steam Letdown to LLP Steam
- LLP Steam Letdown to the Surface Condenser

The design incorporates a UHP steam to HP steam letdown station such that the Plant is able to startup using the steam from the HRSG while the Combustion Turbine is operating on natural gas.

In addition to the letdown valve stations, the Power Block includes several steam bypass stations for Steam Turbine startups and trips. The Power Block has the following steam bypass stations:

- UHP Steam Bypass to CRH Steam
- HRH Steam Bypass to the Surface Condenser
- LP Steam Bypass to the Surface Condenser

ii) Heat Recovery Steam Generator (HRSG)

The Heat Recovery Steam Generator (HRSG) takes the hot exhaust gases from the Combustion Turbine and converts it into high-energy steam which produces power with the Steam Turbine. Immediately after the Combustion Turbine's exhaust, there are two sets of

duct burners inside the HRSG duct. One set of duct burners consume excess treated syngas, and the other duct burners consume PSA off-gas and ammonia vent gas. The duct burners increase the exhaust gas temperature, thus increasing the steam production in the HRSG. The HRSG will meet ASME Section I Fired Boiler standards and consist of two steam drums (ultra high pressure and medium pressure), superheating sections, reheating sections, economizers, and a low temperature economizer section.

The HRSG also has the following secondary functions of:

- Warming up the UHP BFW for use in the Combustion Turbine's TCA cooler
- Supplying high and low temperature flue gas to Gasification for coal drying
- Providing hot HHP BFW to the Clean Syngas Performance Heater
- Providing hot HHP BFW to the Nitrogen Diluent Performance Heater
- Providing hot HHP BFW for the HHP BFW blending

The HRSG will have a selective catalytic reduction (SCR) system for NO_x control. It utilizes vaporized anhydrous ammonia to reduce the NO_x emissions from the HRSG stack. The SCR system consists of an ammonia flow control skid, dilution fans, and an ammonia injection grid. The HRSG will also have a CO catalyst to reduce the CO emissions from the HRSG stack. A continuous emissions monitoring system (CEMS) monitors the emissions from the HRSG stack.

HECA's HRSG is more complex than a typical combined cycle or cogeneration HRSG. The HRSG's design evolved during the course of FEED and is expected to evolve further during detailed engineering. An example of a complex section within the HRSG is the low temperature economizer. The condensate in the low temperature economizer must be above 140 °F to prevent condensing the moisture in the HRSG flue gas onto the surface of the low temperature economizer tubes. In addition, the condensate leaving the low temperature economizer must be below 230 °F in order for the Deaerator to operate properly. Because of the different Combustion Turbine fuels and operating conditions, the low temperature economizer has bypasses and a recirculation pump to stay within the required temperature range.

iii) Balance of Power Block / BFW / Low & High Temperature Flue Gas Ducting

a. Boiler Blowdown System

The Boiler Blowdown System collects high energy streams, such as the continuous and intermittent blowdown from the HRSG steam drums and the Gasification Unit. The Boiler Blowdown System also removes condensate from the steam lines, especially

during startups and steam line with normally saturated steam. The high energy streams flash in either the HRSG Blowdown Drum or the Atmospheric Blowdown Drum. The flashed steam discharges to the atmosphere while the flashed condensate collects in the HRSG Blowdown Sump through a network of underground pipes. Circulating water quenches the condensate collected in the HRSG Blowdown Sump to 140 °F before the HRSG Blowdown Sump Pumps discharges the water into the circulating water return line.

b. Boiler Feedwater System

The Boiler Feedwater System consists of two sets of pumps, the UHP BFW Pumps and the HHP/LP Boiler Feedwater Pumps. These pumps take suction from a common Deaerator and supply the feedwater demand of the entire Plant which has several steam boilers operating at different pressures. The UHP BFW Pumps supply feedwater to the UHP Steam Drum, desuperheating water to the UHP Superheater in the HRSG, and cooling water to the Combustion Turbine's TCA cooler. The HHP/LP Boiler Feedwater Pumps supply HHP feedwater to several users including the MP Steam Drum, the Waste Heat Boiler in Gasification, hot feedwater for the Clean Syngas and Nitrogen Diluent Performance Heaters, the Auxiliary Boiler, and various HP and MP feedwater consumers within the Plant. An interstage bleed from the HHP/LP Boiler Feedwater Pumps supplies LP feedwater to various users within the Plant.

One of the primary destinations for the HHP/LP BFW Pumps is Gasification's Waste Heat Boiler which requires a constant HHP feedwater temperature of 356 °F. To meet this requirement, the HHP feedwater flows through the HRSG's HHP Economizer to gain some temperature, which always exceed 356 °F. Then a side stream from the economizer outlet blends with cooler HHP feedwater from the HHP/LP BFW Pumps discharge before going to the Waste Heat Boiler.

The Waste Heater Boiler also requires 356 °F HHP feedwater during startups, during which time the Combustion Turbine and HRSG may be idle and unable to provide Gasification with the required HHP feedwater temperature. Therefore, a BFW Backup Steam Heater has been added to meet the temperature requirement by utilizing MP Steam as the heating medium.

The Deaerator receives makeup water from three main sources: steam condensate from the Surface Condenser; steam condensate return from various process units; and demineralized water. The Sour Shift Unit utilizes demineralized water as a heat transfer medium prior to entering the Deaerator at roughly 230 °F.

c. Chemical Injection System

The Chemical Injection System is set up for a phosphate continuum per EPRI recommendations for a combine cycle applications. The system provides treatment of the boiler feedwater to control deposition and corrosion consisting of chemical totes and metering pumps. Disodium phosphate or trisodium phosphate is the recommended coagulant for the steam drums.

The chemical injection system is designed such that every steam generator has its own phosphate injection system. This allows better drum water chemistry control at each individual steam generator instead of a single phosphate injection point near the boiler feedwater pumps.

d. Closed Cooling System

The Power Block Closed Cooling Water System supplies closed cooling water to equipment in both the Power Block and Gasification. Circulating water from the Power Block Cooling Tower cools the Closed Cooling Water System.

e. Condensate System

The Condensate System condenses steam from the Steam Turbine exhaust and returns the condensate to the Deaerator. Major equipment in the system includes the Surface Condenser, the Condensate Pumps, the Hogging Jet Ejectors, the Steam Jet Air Ejectors (SJAЕ), and the Gland Steam Condensers (GSC).

f. Flue Gas System

HRSG flue gas is used to dry the coal feedstock for Gasification. The Flue Gas System takes HRSG flue gas at two locations, before the MP Steam Drum (high temperature flue gas) and after the last economizer coils (low temperature flue gas). A High Temperature Flue Gas Blower and a Low Temperature Flue Gas Blower send the HRSG flue gas to Gasification in two separate ducts. The flow of each flue gas stream is controlled to achieve the temperature required by Gasification.

g. Fuel Gas System

The primary fuel to the Combustion Turbine is treated syngas from the AGR Unit. The Clean Syngas Performance Heater preheats the syngas to 302 °F which increases the overall efficiency of the Combustion Turbine. Hot HHP BFW from the HHP Economizer coils at the HRSG is the heating medium for the Clean Syngas Performance Heater. After

the heater, the syngas passes through the Clean Syngas Filter/Separator and into the Combustion Turbine. The Clean Syngas Filter/Separator is located downstream of the performance heater in case of a tube leak. This gives the filter/separator a chance to remove any liquid which might damage the Combustion Turbine.

During natural gas operation, the Natural Gas Electric Heater ensures the natural gas is sufficiently above the dew point. After the Natural Gas Electric Heater, the natural gas passes through the Natural Gas Filter/Separator located downstream of the electric heater before entering the Combustion Turbine.

h. Nitrogen Diluent System

When operating on syngas, the Combustion Turbine requires nitrogen to dilute the syngas for NO_x control. The Nitrogen Diluent Performance Heater preheats the nitrogen to 302 °F increasing the overall efficiency of the Combustion Turbine. Hot HHP BFW from the HRSG HHP Economizer coils is the heating medium for the Nitrogen Diluent Performance Heater. After the heater, the nitrogen flows through the Nitrogen Diluent Filter/Separator and ultimately into the Combustion Turbine. The Combustion Turbine's combustion system performs the syngas and nitrogen mixing at the fuel gas module. The Nitrogen Diluent Filter/Separator is downstream of the performance heater in case of a tube leak providing the filter/separator a chance to remove any liquid which might damage the Combustion Turbine.

The CO₂ purification process uses a catalyst to remove methanol from the CO₂ product stream. The catalyst regeneration process uses nitrogen to remove methanol from the catalyst resulting in a nitrogen stream with a small amount of methanol. This stream combines with the main nitrogen diluent line to the Combustion Turbine.

i. Sampling System

The Sampling System continuously monitors the steam and water purity at specific points in the Power Block cycle. This monitoring is vital to the longevity of the steam drums and Steam Turbine.

3.7.9 Fertilizer Complex

The main objective of the Fertilizer Complex is to convert a portion of the purified hydrogen and carbon dioxide produced in the gasifier into the following saleable fertilizer products:

- Solid Urea Pastilles
- Urea Ammonium Nitrate (UAN-32) Solution

The Fertilizer Complex consists of the following units:

- Ammonia Synthesis Unit
- Urea Unit
- Solid Urea Production Unit
- UAN Complex, comprised of:
 - Nitric Acid Plant
 - Ammonium Nitrate Plant
 - UAN Blending

A technical evaluation led to the selection of Ammonia Casale for the Ammonia Synthesis Unit, Urea Casale for the Urea Unit, and Weatherly for the UAN Complex. These technology providers prepared Confidential process Design Packages (PDPs) during FEED that applied their proprietary fertilizer technologies to the HECA Project. Casale's Ammonia & Urea processes and Weatherly's UAN process are licensed technologies that are protected by NDAs.

Design information for the Solid Urea Production Unit was provided by Sandvik and was based on their proprietary urea pastillation process.

The system description that follows is a non-confidential overview of the combined Fertilizer Complex and the integration of the four (4) units within the complex.

The overall configuration for the Fertilizer Complex is shown in Figure 3-7.

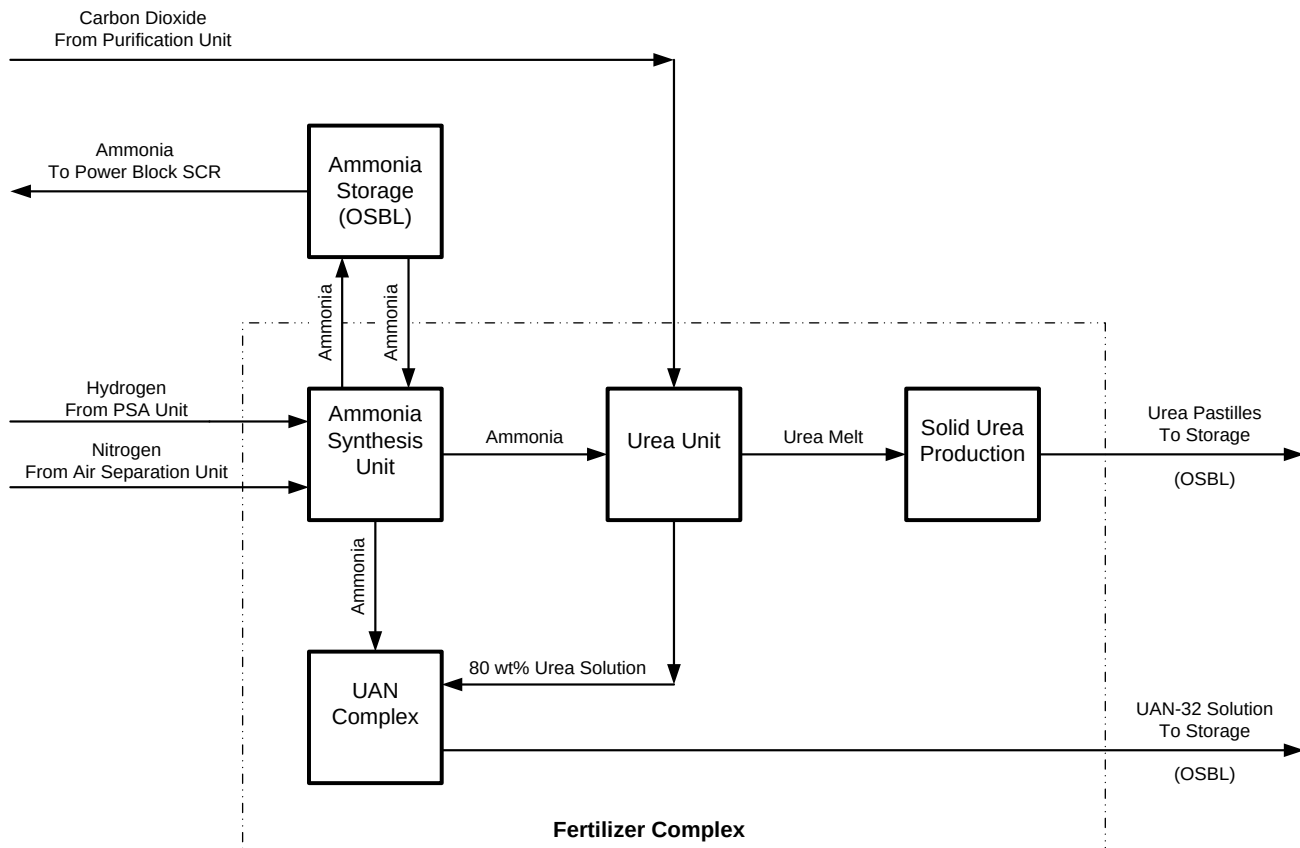


Figure 3-7: Fertilizer Complex Overall Configuration

A. Design Basis

i) Unit Capacity

The nominal design capacities of the individual units in the Fertilizer Complex are listed below:

Table 3-38: Fertilizer Complex Design Capacities

Unit Name	Product	Design Capacity (nominal)
Ammonia Synthesis Unit	Anhydrous Liquid Ammonia	2,100 STPD
Urea Unit	Urea Melt	1,720 STPD (100% basis)
	80 wt% Urea Solution	500 STPD (100% basis)
Solid Urea Production	Solid Urea Pastilles	1,720 STPD
UAN Complex	UAN-32 Solution	1,400 STPD

ii) Feed Source

The Fertilizer Complex receives the following feed streams:

- High purity carbon dioxide from the CO₂ Compression & Purification Unit
- High purity hydrogen from the PSA & Off-Gas Compression Unit
- High purity nitrogen from Air Separation Unit (ASU)

iii) Product Specifications

The intermediate and final products of the Fertilizer Complex are as follows:

- Anhydrous liquid ammonia
- Urea melt (for supply to the Pastillation Unit)
- 80 wt% urea solution (for supply to the UAN Complex)
- Solid urea pastilles
- Urea Ammonium Nitrate (UAN-32) solution

The product specifications are shown in Tables 3-39 through 3-43.

Table 3-39: Anhydrous Liquid Ammonia (at Storage Tank)

Parameter	Value
Composition	
Ammonia	99.95 mol% (min)
Hydrogen	5 ppmv (max)
Methane	5 ppmv (max)
Oil	1 ppmw (max)
Temperature (at storage)	-28 °F
Pressure (at storage)	14.54 psia

Table 3-40: 80 wt% Urea Solution (to UAN Unit)

Parameter	Value
Composition	
Urea (urea + biuret)	80.0 wt% (min)
Biuret	0.7 wt% (max)
Free Ammonia	0.2 wt% (max)
Water	Balance
Temperature	213 °F
Pressure	116 psig

Table 3-41: Urea Melt (to Pastillation)

Parameter	Value
Composition	
Urea (urea + biuret)	99.7 wt% (min)
Biuret	< 0.9 wt%
Free Ammonia	< 0.05 wt%
Water	0.3 wt% (max)
Temperature	273 °F (max)
Pressure	87 psig

Table 3-42: Urea Pastilles

Parameter	Value
Size	2 – 4 mm
Crushing Strength	40 N (9 lbf)
Shape	Hemispherical
Angle of Repose	30°
Temperature	113 °F

Table 3-43: UAN-32 Solution (to Storage)

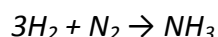
Parameter	Value
Composition	
Ammonium Nitrate	44.3 wt%
Urea	35.4 wt%
Water	20.3 wt%
Free Ammonia	0.05 wt% (max)
Biuret	0.3 wt% (max)
Temperature	100 °F
Pressure	35 psig

B. Process Description

i) Ammonia Synthesis Unit and Ammonia Storage

The Ammonia Storage is organizationally part of the OSBL area. However, it is functionally part of the Ammonia Synthesis Unit, and is therefore described in this section.

The high purity hydrogen from the PSA Unit and high purity nitrogen from the Air Separation Unit feed the Ammonia Synthesis Unit in a 3:1 molar (stoichiometric) ratio. The feed gases react over catalyst to produce ammonia per the following reaction:



The ammonia is condensed, purified, and cooled to -28 °F. It is sent to the ammonia storage tanks.

The ammonia storage tanks are used to hold an inventory of ammonia to act as a buffer between the Ammonia Synthesis Unit and the downstream units. The tanks facilitate start-up and shut-down of the Ammonia Synthesis Unit by de-coupling it from the downstream units. Furthermore, they allow the downstream users of ammonia to continue operation should the ammonia plant ever need to shut down during normal plant operation. The Ammonia Storage System comprises two storage tanks, a refrigeration package, and ammonia transfer pumps.

The ammonia produced in the Ammonia Synthesis Unit is distributed throughout the HECA plant from the storage tanks:

- A small amount of ammonia is used in the Power Block SCR.
- Approximately 18% of the ammonia product is sent to the UAN Complex for nitric acid synthesis and ammonium nitrate production.
- The balance of the ammonia product (approximately 82% of the total) is sent to the Urea Unit for urea synthesis.
- Planned operations do not include liquid anhydrous ammonia as a product. However, the design includes space allocation and loading facilities in the event that future operations are revised to include ammonia as a saleable product. The loading facilities are illustrated on the OSBL process flow diagram 127-25-PFD-0201.

The ammonia feed to the Urea Unit and the UAN Complex is heated in the Ammonia Synthesis Unit to 68 °F before export. All of the ammonia will be used on-site.

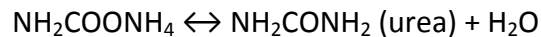
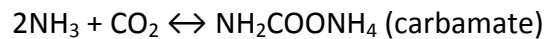
The Ammonia Synthesis Unit also produces and exports high pressure steam.

The licensors design for the Ammonia Synthesis Unit did not include all required systems. The following systems were designed by Fluor:

- Phosphate injection for the boiler feed water treatment. This system comprises a chemical injection skid. The phosphate is added to the BFW on flow ratio control.
- Boiler blowdown system, from the Ammonia Synthesis Plant's steam drum. This system comprises a drum to collect the blowdown and a pump to send the flashed blowdown to the cooling water return header. The blowdown is pumped out on level control.

ii) Urea Unit

Ammonia from the Ammonia Synthesis Unit and high purity carbon dioxide from the CO₂ Compression & Purification Unit feed the Urea Unit in a 2:1 ratio. The feed gases react at high pressure and temperature to produce urea per the following reactions:



The urea is purified and concentrated to two different products:

- 1) 78% of the urea is concentrated to 99.7 wt%, producing a urea melt that is sent to the Solid Urea Production to make a solid urea product.
- 2) 22% of the urea is concentrated to 80 wt% aqueous solution, which is sent to the UAN Complex (Unit 84) to blend with ammonium nitrate in the production of UAN solution.

The urea/carbamate solutions generated in the synthesis unit are highly corrosive. These components utilize carbon steel shells for pressure containment, and are lined with special grade stainless steels for the corrosion protection. These components also require special monitoring to ensure that the liners do not leak and allow the corrosive components to contact the carbon steel bodies.

Process water produced in the Urea Unit is highly treated in order to obtain water containing less than a few parts per million of urea and ammonia before being discharged from the unit.

The Urea Unit also produces and exports low pressure steam.

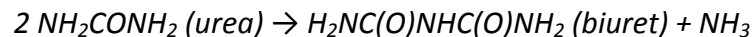
iii) Solid Urea Production

The Solid Urea Production system solidifies the urea melt from the Urea Unit to make a solid urea product.

It is expected that the urea solidification will be accomplished by a pastillation system offered by Sandvik. The resulting product is urea pastilles, which are sold to the agricultural industry as fertilizer.

The pastillation system consists of a rotoformer head that drops discrete quantities of urea melt onto a moving water-cooled conveyor belt, on which the urea freezes. The resulting pastilles are then transferred via belt and bucket conveyors to Urea Storage.

A side reaction degrades the hot urea melt into a corrosive contaminant, biuret, by the following reaction:



The reaction occurs irreversibly at the melt temperature. Higher temperatures and longer residence times result in more biuret growth. The design of the urea melt concentration system, the Solid Urea Production system, and the transfer piping between the Urea Unit and the Solid Urea Production system takes this into consideration by minimizing residence time of the melt in these systems and limiting the exposure to higher temperatures.

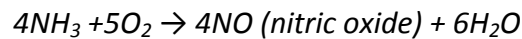
iv) UAN Complex Unit

The UAN Complex converts ammonia from the Ammonia Synthesis Unit and 80 wt% urea solution from the Urea Unit into urea ammonium nitrate (UAN) solution. The UAN product has a nitrogen content of 32% by weight, which designates the product as UAN-32 solution.

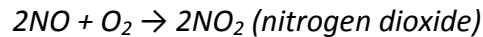
The UAN Complex comprises three parts:

- Nitric Acid Plant
- Ammonium Nitrate Plant
- UAN Blending

In the Nitric Acid Plant, ammonia is reacted with air at high temperature over a platinum catalyst to form nitric oxide via the following equation:



The nitric oxide further reacts with additional oxygen to form nitrogen dioxide:

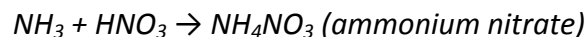


The nitrogen dioxide is absorbed in water to make nitric acid:



The resulting nitric acid is concentrated to 57 wt% and sent to a Nitric Acid Storage Tank. This tank buffers the Nitric Acid Plant from the Ammonium Nitrate Plant downstream, thereby allowing the ammonium nitrate production to continue when the nitric acid catalyst requires replacement, which is required approximately every 90 days.

In the Ammonium Nitrate Plant, nitric acid is reacted with vaporized ammonia at low pressure to form a 79 wt% ammonium nitrate solution:



Finally, the ammonium nitrate is mixed with 80 wt% urea solution in the UAN blending system to produce the urea ammonium nitrate solution product. The ammonium nitrate and the urea are blended at a ratio such that the UAN solution has a nitrogen content of 32 wt%.

The UAN-32 solution is sent to the UAN Storage Tanks and then sold as a fertilizer product via rail or truck shipments.

The UAN Complex also produces and exports high pressure steam.

Licensors design responsibility for the UAN Complex did not include all of the required systems. The other needed systems were designed by Fluor:

- Phosphate injection for the boiler feed water treatment. This system comprises a chemical injection skid. The phosphate is added to the BFW on flow ratio control.
- Corrosion inhibitor injection for the UAN-32 solution product. This system comprises a tank for holding the corrosion inhibitor and a chemical injection skid. The corrosion inhibitor is added to the product UAN-32 on flow ratio control.

- UAN solution start-up tank system. During start-up of the UAN Complex, the initial UAN-32 product will be off-spec, mostly due to it containing too much water and therefore being too dilute to meet the product specification. Instead of sending the off-spec solution into the UAN Storage Tanks, the product will be sent to the UAN Solution Start-Up Tank until the product is on-spec (up to 24 hours). The off-spec product will then slowly be blended in with the on-spec product en route to the UAN Storage Tanks.

C. Operating Flexibility

i) Turndown

The Ammonia Synthesis Unit is designed for an operating range of 60 – 100%.

The Urea Unit is designed for an operating range of approximately 77 – 100% for two-product operation (urea melt and 80 wt% urea solution) or as low as 62% of design capacity for urea melt production only, with the following limitations within the unit:

- 80 – 100% operating range for the urea melt evaporator system, limited primarily due to excessive biuret formation in the evaporator and melt lines with low flows/high residence times at the operating temperature.
- 65 – 100% operating range for the 80% urea solution evaporator system
- 50 – 100% operating range for the overall vacuum system in the urea solution concentration and evaporation system
- 60 – 100% operating range for the balance of the urea production facility

The Urea Pastillation Unit is designed for the following:

- 80 – 100% operating range for each rotoformer.
- Individual rotoformers can be turned off to reduce overall pastillation production rate.
- Overall theoretical capacity range is therefore approximately 8–100%. However, the maximum realistic turndown for this overall system is limited by biuret formation in the urea concentration system and urea melt transfer line.

The UAN Complex is designed for an operating range of 70 – 100%.

ii) Equipment Design Factors

All units in the Fertilizer Complex are designed for 100% EOR operation.

iii) Sparing Philosophy

All continuously operating pumps are 100% spared.

Ammonia Storage consists of two tanks for a 7-day total ammonia production capacity. Normally, both tanks will be used. However, one tank may be isolated for maintenance if necessary.

The Urea Pastillation Package comprises 11 rotoformers. Of these, 10 are required to meet project design capacity, and one is available as a spare to enable periodic unit maintenance.

A spare converter basket and catalyst load for the Nitric Acid Plant is recommended to facilitate and expedite catalyst changes in the UAN Complex, which are required every 90 days (approximately).

3.7.10 Water Treatment Plant

The proposed Water Treatment Plant is a zero liquid discharge (ZLD) facility designed to meet the HECA Project's process and service water needs. All collected storm water and facility-generated wastewater streams will be treated on site and reused within the facility.

The design for the Water Treatment Plant was provided by a water treatment specialty contractor in the form of a Confidential FEED Package. The FEED Package was developed by Jacobs Engineering Group (JEG) and is protected by an NDA.

The Water Treatment Plant consists of the following units:

- Raw Water Treatment Unit
- Demin Water System Treatment Unit
- Wastewater Treatment Unit

This system description provides a non-confidential overview of the HECA Water Treatment Plant.

A. Design Basis

i) Unit Capacity

The Water Treatment Plant is designed to handle 5,200 gpm of raw water.

ii) Design Cases

The design of the Water Treatment Plant is based on the cases described in the table below.

Table 3-44: Case Definition – Water Treatment Plant

Cases	Description
090-01	On-peak operation @ 97°F Ambient
090-02	Off-peak operation @ 39°F Ambient

iii) Feed Source

The Raw Water Treatment Unit receives the Project's raw water supply (brackish ground water) from the Buena Vista Water Storage District (BVWSD). It also receives treated effluent from the Wastewater Treatment Unit.

The Demin Water System Treatment Unit treats cooling tower blowdown from the Process & Power Block Cooling Towers. It also receives a portion of treated water that bypasses the Process and Power Block Cooling Towers, and provides makeup water for the ASU Cooling Tower.

The Wastewater Treatment Unit processes the following streams:

- Process wastewater from Gasification
- Process wastewater from the Sour Water Stripper
- Process wastewater from Acid Gas Removal
- Storm water (contaminated and non-contaminated)
- Recovered utility water

B. Process Description

i) Raw Water Treatment

The Raw Water Treatment Unit produces makeup water for the Process Cooling Tower and Power Block Cooling Tower.

Raw water is pumped from the Raw Water Equalization Tank to a lime-soda softening process, which operates on in the "cold lime" range (approximately 65 °F). Hydrated lime (calcium hydrate) and soda ash (sodium carbonate) are added in the softener to precipitate the hardness minerals, principally calcium (as carbonate) and magnesium (as hydroxide). A reduction in calcium and magnesium is expected in the range of 80% to 90%. Magnesium hydroxide precipitates will also serve to reduce silica through coprecipitation. Significant reductions of iron (98%), manganese (98%), silica (45%), and strontium (90%) are also expected. A portion of the sludge from the softening process is recirculated to the reaction zone within the softener to provide seed crystals to enhance precipitation. A polymer is added to encourage particle agglomeration to improve settling in order to produce low turbidity product water. An additional coagulant such as ferric chloride may be added to aid in floc formation.

The softener unit includes an integral sludge thickener. This “picket fence” type thickener allows this unit to produce sludge with typically 15% solids.

Accumulations of excess, thickened sludge are periodically pumped to the sludge holding tank where the sludge is mixed to maintain a homogeneous liquid holding the particles in suspension. The sludge is ultimately forwarded to a plate-and-frame filter press for dewatering. The dewatered sludge solids are conveyed to roll-off bins and then hauled away for disposal offsite. Filter press filtrate is returned to the Raw Water Equalization Tank.

The softener overflow (softened water outlet) is pumped to the Treated Water Storage Tank. Acid is added prior to the tank to reduce the pH of the softened water to stop any continuing softening reaction to prevent the formation of lime scale on downstream pipes, tanks, and equipment. The acid will also dissolve minute particles of precipitate that may carry over from the softener, thereby reducing the turbidity of the treated water. Outlet turbidities are expected to be less than 5 Nephelometric Turbidity Units (NTU) and at times may be as low as 1 NTU under steady state operation.

Several recycled water streams flow to the Treated Water Storage Tank including: excess 1st pass RO product water; 2nd pass RO concentrate; and, Electro – Deionization (EDI) concentrate. Treated water is pumped from the Treated Water Storage Tank to the Power Block Cooling Tower and the Process Cooling Tower, where it is combined with the following streams:

- ASU cooling tower blowdown
- Evaporative cooler blowdown
- Steam generation blowdown
- Treated process condensate from the Urea Plant
- Condensed water from the UAN Complex Air Compressor Intercooler

A portion of the treated water bypasses the cooling towers and is sent directly to the Demin Water System Treatment Unit where it is combined with softened water downstream of the Cooling Tower Blowdown Softener. This cooling tower bypass augments the flow of cooling tower blowdown to provide adequate flow to the UF and downstream processes. This allows the cooling towers to be operated on a fixed Total Dissolved Solids (TDS), but varying flow basis.

ii) Demin Water System Treatment

The Demin Water System Treatment Unit treats cooling tower blowdown to provide makeup water for the ASU Cooling Tower, utility water, evaporative cooler makeup water, and demineralized water.

The cooling tower blowdown is first treated utilizing lime-soda softening operating in the “cold lime” range (approximately 68-78 °F). Hydrated lime and soda ash are added in the softener to precipitate the hardness minerals, principally calcium and magnesium. About 80-90% reduction of calcium and magnesium is expected. A 50% reduction of strontium and silica is also expected. Iron and manganese are not expected to be present in the Treated Water in significant quantities. A portion of the sludge from the softening process is recirculated to the reaction zone within the softener to provide seed crystals to enhance precipitation. A polymer is added to encourage particle agglomeration to improve settling in order to produce low turbidity product water. An additional coagulant such as ferric chloride may be added to aid in floc formation. Sodium hypochlorite is added for control of biological growth.

The softener unit includes an integral sludge thickener. This “picket fence” type thickener allows this particular unit to produce sludge of typically 15% solids. Accumulations of excess sludge are periodically pumped to the sludge holding tank where it is handled along with the sludge from the Raw Water Softener.

The softened water outlet is sent to the membrane Ultrafilters (UF). Prior to the filters, acid is added to reduce the pH of the softened water to stop any continuing softening reaction to prevent the formation of lime scale on the filter media and downstream pipes, tanks, and equipment.

The filtered water quality is expected to be less than 0.1 NTU and consistently less than or equal to 2 Silt Density Index (SDI).

UF filters require regular backwashing with filtered water. Backwash is pumped through the UF membranes and then sent to the Process Waste Sump in the Raw Water Treatment Unit.

Filtered water is pumped to the First Pass Reverse Osmosis (RO) Unit. Prior to the First Pass RO Unit, the filtered water is treated with the following:

- Sodium bisulfite to destroy any remaining free chlorine in cooling tower blowdown
- Antiscalant to protect the membranes from mineral scale formation
- Biocidal agent to reduce the risk of fouling of the RO membranes from biological growth (intermittent basis)

The First Pass RO Unit is expected to reduce the concentration of most ions by 95% to 99%. The first pass RO concentrate water is too high in TDS to be recovered or recycled, and is therefore sent to the ZLD process within the Wastewater Treatment Unit.

The first pass RO permeate is pumped to two (2) general groups of users:

- (1) Stabilized water for use as ASU cooling tower makeup water, evaporative cooler makeup water, and plant utility water
- (2) High purity users that require demineralized water

Any excess RO permeate is recycled back to the Treated Water Storage Tank.

The stabilization process includes CO₂ injection followed by a re-mineralization step with a calcite filter and the addition of a chemical corrosion inhibitor, which produces a non-scaling utility water suitable for carbon steel piping.

For high purity users, the first pass RO permeate is sent to a forced draft decarbonator, along with large volumes of air. The air is first filtered with high efficiency particulate air (HEPA) and carbon filters to prevent contamination of the RO water with particulates and organic material. The decarbonated water is mixed with caustic prior to further processing in the Second Pass RO Unit.

The Second Pass RO is expected to reduce the concentration of the remaining ions by an additional 95% to 99%.

The second pass RO product water is stored in the Second Pass RO Permeate Hydraulic Break Tank. The second pass RO concentrate is returned to the Treated Water Storage Tank.

Following the second pass RO, the water is further deionized through the electrodeionization (EDI) process. EDI utilizes electric power, ion exchange resins, and charged filter fabrics to reduce the TDS. The EDI concentrate is returned to the Treated Water Storage Tank.

The EDI product water is polished through a bank of trailer-mounted service ion exchange (IX) units. The demineralized water is then distributed to the facility's high purity users.

iii) Wastewater Treatment Plant

Any storm water is collected during rain events from designated process areas. The storm water is retained in retention basins located throughout the facility and is eventually pumped back to the Wastewater Treatment Plant for treatment. The storm basin water will go through initial screening and settlement of large particles prior to being pumped to the Wastewater Treatment Plant.

The utility drain water is a combination of miscellaneous wash/drain wastewater streams from throughout the plant including truck wash water, area wash water from the feed stock handling/slurry preparation areas and the plant's other utility drains which may be contaminated with oil from equipment lube oil drips.

The utility drain water and storm water streams are treated separately from the Gasification, Sour Water Stripper, and AGR wastewater streams.

Utility drain water and storm water is sent to the Corrugated Plate Interceptor (CPI) Feed Tank. Reuse of these waste streams will require the removal of oil, methanol, formic acid, total suspended solids and cyanide. The utility drain water will be pre-treated utilizing a pH adjustment and demulsifier, followed by a CPI Separator.

Separately, the process wastewater streams are oxidized and clarified in the Wastewater Oxidation Clarifier. The streams are oxidized using potassium permanganate. To achieve the target pH, caustic may be required due to the expected low pH of the Sour Water Stripper Unit's wastewater.

The design incorporates a Contraflo™ Solids Contact Clarifier-Type CT (or equivalent). This type of combination reactor clarifier will allow for substantial reaction time for the oxidation of organics and settling time for the produced manganese dioxide and other suspended solids. One of the products of the oxidation reaction is carbon dioxide. Some of the carbon dioxide may be emitted from the clarifier but in quantities considered to be insignificant.

Effluent streams from the CPI Separator and the Oxidation Clarifier are combined and pH adjusted to 11. Both a coagulant and a flocculant will be added in a flocculator tube prior to an Induced Air Flotation (IAF) Unit. The effluent from the IAF will be pumped through de-oiler water filters for the removal of soluble Total Organic Carbon (TOC).

The effluent from the de-oiler water filters will be injected with hydrogen peroxide prior to passing through an ultraviolet disinfection system. All residual TOC/Chemical Oxygen Demand (COD) will be removed at this point. The treated stream will then be returned to the Raw Water Equalization Tank.

All solids removed from the Oxidation Clarifier, CPI Separator and IAF will gravity transfer to a lined wet well. These solids will be mixed and pumped to a plate and frame filter press for dewatering. The dewatered solids will be shipped offsite for final disposal as a non-hazardous material. The effluent from the filter press will be transferred to the CPI Feed Tank.

The Wastewater Treatment Plant also includes a zero liquid discharge (ZLD) process to treat 1st pass Reverse Osmosis (RO) concentrate water from the Demin Water System Treatment Unit. The ZLD produces a solid waste for offsite disposal.

The four step ZLD process is comprised of the following components:

- 1) Deaerator
- 2) Falling film evaporator
- 3) Crystallizer
- 4) Decanting centrifuge

The deaerator removes carbonate species from the brine to prevent fouling prior to evaporation and crystallization. The deaerator uses steam from the distillate collection system to effectively remove the carbon dioxide created during the acidification process.

After the deaerator, the stream is sent to the evaporator to minimize flow to the crystallizer. The falling film evaporator uses a seeded slurry system consisting of a calcium chloride feed and a hydrocyclone to produce calcium sulfate seeds. These seeds will provide a surface that silica particles will preferentially coagulate with effectively minimizing the amount of silica scale in the components of the evaporator system. Calcium sulfate crystals saturated with silica will be allowed to pass to the crystallizer.

The evaporator concentrate combines with filtrate from the decanting centrifuge and is introduced to the crystallizer. The crystallizer produces a slurry capable of being dewatered. The flash steam from the evaporator will pass through a condenser and be combined with the crystallizer distillate. Crystal slurry from the crystallizer body will be pumped batch-wise to a decanting centrifuge.

The dewatered salt cake will be disposed of offsite as a non-hazardous material, while the ZLD distillate combines with First Pass RO permeate for stabilization in the Demin Water System Treatment Unit.

3.7.11 OSBL (Utilities & Offsites)

The Outside Battery Limits (OSBL) areas are comprised of the common utility systems, common facilities, and the other equipment/systems located outside process unit boundaries required to support various units within the Plant. This section summarizes the following key systems of the HECA facility:

- Cooling Water
- Recovered Condensate
- Auxiliary Boiler
- Emergency Diesel Generators
- Plant & Instrument Air
- Flare
- Natural Gas Distribution
- Storm Water System
- Solids Handling Drainage System
- Oily Water Sewer
- Rail & Truck Feedstock Unloading, Handling & Storage
- Gasification Solids Storage, Handling & Rail / Truck Loading
- Sulfur Liquid Storage, Handling & Rail / Truck Loading
- Ammonia and Urea- Ammonium Nitrate Solution (UAN) Liquid Storage, Handling & Rail / Truck Loading
- Firewater / Fire Protection System

A. Cooling Water System

The HECA Project includes three (3) independent cooling water systems:

- 1) Process Cooling Water System
- 2) Power Block Cooling Water System
- 3) Air Separation Unit (ASU) Cooling Water System

The ASU is a third-party design, build, own, and operate (DBOO) facility, with a separate mechanical-draft cooling system included in the ASU scope of supply.

The Power Block Cooling Tower and the Process Cooling Tower share a common Chemical Injection System which includes a sodium hypochlorite system, a dispersant system, a corrosion inhibitor system, and a sulfuric acid system. The system provides treatment of the Cooling Tower circulating water to control deposition, corrosion, and biofouling. The system also includes a sodium hypochlorite shock treatment system for commissioning or when bio fouling growth is excessive and flow rates above the normal design flow are required.

The process descriptions for the Process and Power Block cooling water systems are provided in the narrative that follows.

i) Process Cooling Water System

The Process Cooling Water System is dedicated to meet the circulating water demands of the following areas:

- Gasification
- Gas Treating
- Acid Gas Removal (AGR) & Refrigeration
- CO₂ Compression & Purification
- Sulfur Plant
- PSA & Off-Gas Compression
- Fertilizer Complex
- OSBL (including utilities and offsites)

The mechanical-draft type, counter-flow cooling tower is equipped with high-efficiency drift eliminators. The cooling tower has a design cooling duty of 1,115 MMBTU/hr with a circulation rate of 162,000 gpm. There are three 50% Process Block Cooling Water Pumps.

The main distribution headers to and from the cooling tower are piped underground and sent to all users in a one-pass distribution system. The normal cooling water supply and expected return temperatures are 80°F and 94°F, respectively.

A portion of the cooling water return from the AGR unit is routed to the Ammonia Heater. The Ammonia Heater warms incoming anhydrous ammonia to 60° F. The CWR enters the Ammonia Heater at about 92° F and is sufficient to heat cold anhydrous ammonia for loading.

The cooling tower blowdown is routed to the Water Treatment Plant where it is treated to produce demineralized water as well as utility water and treated makeup water for the ASU cooling tower and makeup water for the evaporative cooler.

Make-up water is required to replace losses due to evaporation and blowdown. Makeup water to the Process Cooling Tower is a blend of softened filtered raw water from the Water Treatment Plant, boiler blowdown, evaporative cooler blowdown, ASU cooling tower blowdown, treated process condensate from the Urea Unit, and second pass RO reject.

ii) Power Block Cooling Water System

The Power Block Cooling Water System provides the cooling needs of the Power Block. Most of the circulating water is used in the Surface Condenser, while a side stream provides cooling to the Power Block Closed Cooling Water System. The Power Block Cooling Tower is an induced mechanical draft, multi-cell counter-flow design complete with high efficiency drift eliminators. The cooling tower has a design cooling duty of 983 MMBTU/hr with a circulation rate of 97,800 gpm. There are two 50% Circulating Water Pumps.

The maximum circulating water return temperature occurs during a full load Steam Turbine bypass or trip scenario. During the summer design ambient (97 °F, 20% RH), the calculated return temperature reaches as high as 117 °F during the trip scenario. Since the solubility of dissolved solids in water is lower at higher temperatures, it is possible for dissolved solids to precipitate out of the circulating water. This can cause premature fouling in the Surface Condenser tubes or the Closed Cooling Water Heat Exchangers. During operations, it is important to maintain the circulating water supply temperature below 120 °F.

B. Recovered Condensate

The HECA Project requires the use of steam during startup, shutdown, and normal operation of various process units. A portion of the consumed steam is lost within the process, while the rest is recovered as condensate. There are six condensate collection systems throughout the Plant. Five are located within the Process Areas and one is located within the OSBL. This description covers the OSBL Recovered Condensate System.

The LP Condensate Flash Drum receives recovered condensate from the CO₂ Compression & Purification Unit, the Auxiliary Boiler, and the LP steam header steam traps located in the OSBL interconnecting piperacks. Condensate is flashed at atmospheric pressure in the LP Condensate Flash Drum. An exhaust head installed in the flash drum vent piping is used to minimize steam loss to the atmosphere.

There are two 100% LP Condensate Pumps available to transfer the condensate from the LP Condensate Flash Drum to the Deaerator located in the Power Block via the OSBL Pumped Condensate Collection Header. The OSBL Pumped Condensate Collection Header combines with the pumped condensate from the Gas Treating Area, AGR, Sulfur Plant, and Fertilizer Complex.

C. Auxiliary Boiler

An auxiliary boiler is required to supply high pressure steam to Gasification, the Power Block and other users during start-up, or when there is a need for steam within the facility when the Power Block is not in full service. It may also be used during the pre-commissioning for steam blow purposes as well as during routine facility start-ups when steam is not being produced in the Power Block.

The auxiliary boiler is a 2-drum packaged unit that is equipped with low NO_x burners and flue gas recirculation (FGR) for emissions control. A Selective Catalytic Reduction (SCR) is also provided for NO_x control and a CO oxidation system for CO/VOC control. The boiler is only fired on natural gas.

Boiler Feedwater is supplied to the Auxiliary Boiler from the Power Block Deaerator. When the boiler is started and high pressure (HP) steam is being generated, the Power Block is able to letdown steam through the Pressure Reducing Stations to provide a supply of medium pressure (MP) and low pressure (LP) steam throughout the facility. The deaerator is then able to transition to its normal operating mode using LP Steam.

D. Emergency Diesel Generators

An Emergency Diesel Generator System is required to provide sufficient emergency electrical power to critical small drivers, instruments, controls and the DCS to allow safe shutdown of the plant during a sudden primary power outage.

The system includes two 50% diesel generators, each sized for 1500 kW (50% of the required emergency load). Upon the loss of the primary electrical supply both generators are started automatically to provide power for the facility.

The emergency generators are to be tested and connected to the plant electrical grid proper to commencing commissioning and start up activities. During normal plant operation, the emergency generators are to be tested on a weekly basis to ensure reliability when required during an emergency.

The two self-contained skid mounted units include the following auxiliaries:

- Controls and control panels with PLC for each unit
- Engine exhaust
- Particulate filter
- Air cooled radiator with fan
- Fuel filter
- Fuel tank
- Lubrication oil system

The fuel tanks are sized to allow the generator to operate for 12 hours at 100% load.

E. Plant & Instrument Air

The primary source of plant and instrument air is from the Air Separation (ASU) Unit. The secondary source of plant and instrument air is provided by the OSBL Plant & Instrument Air Systems as a 100% back up. The secondary source of air is used during the start-up when primary source of air is not available from the ASU. It is also used when the primary source of air is interrupted during the normal plant operations.

The system includes an Air Compressor Package specified to supply about 5,000 SCFM of air. The Air Compressor Package includes air intake with a filter, three stages of compression, two integral interstage coolers and one aftercooler. The package also includes an integral lube oil system, piping, instruments and PLC with a local control panel. The compressor is provided with an electric motor drive and an anti-surge protection system. A cooling water manifold with

throttling valves provides a single point of interface for cooling water supply and return to the skid mounted intercoolers and lube oil cooler.

The cooled compressed air from the compressor is routed to a knock-out (KO) drum to remove any liquid. Any liquid from the KO drum is drained to the Oily Water Sewer (OWS).

The compressed air from the KO drum is then treated in an Air Dryer Package. The Air Dryer Package is a heatless dryer-type designed to dry air to a water dew point of -40°F at 125 psig. The dryer is designed with a minimum capacity of 4,000 SCFM of dry air. The Air Dryer Package includes twin vessels, two Dryer Pre-Filters, two Dryer Post-Filters, instrumentation, local control panel with PLC, and an overpressure protection system. When one vessel is in service, the other is on stand-by or in regeneration mode. Regeneration is expected once the operating vessel reaches a certain dew point and can no longer dry the air.

The dry air from the Air Dryer Package is first sent to the Instrument Air Receiver, where it is then distributed plant-wide via segregated plant and instrument air distribution systems.

F. Flare

The flare system is one of the most important safety features of the HECA Project. It is designed to safely dispose of various gaseous streams through the relief system within the facility in the event of planned, unplanned and upset overpressure events. It is an essential system needed to protect plant personnel, the surrounding community, and facility equipment.

The HECA Project's emergency flare system includes three (3) separate flares:

- 1) Gasification Flare
- 2) Rectisol Flare
- 3) SRU Flare

The Gasification Flare is designed for all warm sweet flare reliefs from the plant. The Rectisol Flare handles cold sweet flare reliefs from the AGR and Fertilizer Complex. The SRU Flare is designed for sour flare reliefs from the AGR and Sulfur Plant.

The Project objective is to minimize flaring of any gas during normal startup operations, and to avoid sour gas flaring. The relief and flare system is designed with the following objectives:

1. Flaring of sour gas is not allowed except in emergencies, such as cases of equipment failure or other major upsets until the problem can be corrected or the plant can be safely shut down. Flaring of sour gas is an infrequent event.
2. Flaring of sweet gas is allowed during startup, shutdowns and in emergencies, such as cases of equipment failure or other major upsets, until the problem can be corrected or the plant can be safely shut down.
3. The pressure relief system is designed to preferentially relieve sweet syngas before sour syngas. In advance of the pressure relief devices opening, pressure controlled venting occurs.
4. The pressure relief systems are designed with inherently safer design principals in order to avoid reliance on control logic and active High Integrity Protection Systems (HIPS) control equipment. Passive safety systems are favored and are used whenever practical.

G. Natural Gas Distribution

Pipeline natural gas is used as fuel during Gasification startup as well as other startup and shutdown operations when the syngas fuel supply is unavailable.

Natural gas is supplied to the site via a high-pressure pipeline operating at a minimum of 350 psig. Pressure regulation and metering (furnished by the pipeline natural gas supplier) is located within the plant boundary.

The Natural Gas Distribution System is designed to knock out liquids that may be present in the pipeline natural gas as well as to compress and/or letdown natural gas to four different pressure levels:

- 1) High high pressure (HHP) natural gas to clean Gasification burners
- 2) High pressure (HP) natural gas for Gasification startup
- 3) Intermediate pressure (IP) natural gas for Combustion Turbine startup
- 4) Low pressure (LP) natural gas for use in fired heaters and boilers, as assist gas to increase the BTU content of flare gas, and to purge flare headers.

The four pressure levels of natural gas are then distributed throughout the plant.

H. Storm Water System

Storm water retention basins are located throughout the HECA facility to collect storm water runoff. These storm water retention basins are classified to store either: 1) non-contaminated storm water, or 2) potentially contaminated storm water.

Generally, the source of potentially contaminated storm water is from the process areas, whereas the non-contaminated storm water source is from areas outside of the process areas.

Non-contaminated storm water runoff is diverted to the unlined retention basins which are located in remote areas of the Project Site. The non-contaminated storm water in the basins evaporates or is absorbed into the soil.

Potentially contaminated storm water is collected and gravity-routed to lined storm water retention basins. Additionally, under plant upset conditions, suspect or contaminated process streams are also diverted to these lined retention basins. After solids have settled, the water is pumped to the Water Treatment Plant.

I. Solids Handling Drainage System

The Solids Handling Drainage System includes collection of wastewater from the wash down of solids handling equipment with utility water and the separation of solids from wastewater. The wastewater is routed to the Wastewater Treatment Plant.

The recovered solids consist mainly of small particles of coke and coal. These particles are manually removed periodically from the settling sump and transported by truck to the coal and coke barn for feed to Gasification.

The operation of the Solids Handling Drainage System is intermittent.

J. Oily Water Sewer

The primary function of the Oily Water Sewer System is to collect and transfer oily water to the Wastewater Treatment Plant for treatment. Oily water resulting from water wash down areas, equipment, or storm run-off is channeled via underground sewer system to the sumps by gravity. Oily water sewers and sumps are strategically located throughout the plant (ASU, Water Treatment, Auxiliary Boiler, Power Block, and OSBL areas) to facilitate collection of oily water / wastewater. The recovered water is then treated and reused within the plant. The recovered oil is disposed of offsite.

K. Rail & Truck Feedstock Unloading, Handling & Storage

The function of the Rail & Truck Feedstock Unloading, Handling & Storage System is to unload coal and coke from trains and trucks and deliver a blended feedstock to and convey the feedstock to the Drying & Milling portion in Gasification.

The system consists of a rail unloading facility, truck unloading facility, feedstock storage system, feedstock reclaim system, feedstock crushing system, and silo fill system.

L. Gasification Solids Storage, Handling & Rail / Truck Loading

Gasification Solids generated in Gasification are conveyed directly onto a covered concrete storage pad (with seven-day storage capacity) for further drying. The storage piles are managed by a front-end loader until reclaimed and conveyed to the rail / truck load-out facility at a rate of 400 tons per hour.

M. Sulfur Liquid Storage, Handling & Rail / Truck Loading

The Sulfur Plant produces a saleable degassed liquid sulfur product. Liquid sulfur from the Sulfur Plant is pumped to the Sulfur Liquid Storage, Handling & Rail / Truck Loading Area for shipment by either truck or rail car. The loading system includes the Sulfur Loading Pumps and the Truck and Rail Car Loading Arms.

N. Urea Pastilles Solids Storage, Handling & Rail / Truck Loading

The Solid Urea product generated in the Fertilizer Complex is conveyed to four (4) concrete storage domes having a total storage capacity of 80,000 tons or 45 days. The urea pastilles are managed within the storage domes by a front-end loader until reclaimed and conveyed to the rail / truck load-out facility at a rate of 400 tons per hour.

O. Ammonia and UAN Storage, Handling & Rail / Truck Loading

The UAN storage and transfer facilities enable railcar and/or truck loading for UAN product export. The design provides the space and transfer facilities to allow for potential for Ammonia product export.

An Ammonia Vaporizer System is included to supply gaseous ammonia to the Power Block HRSG and Auxiliary Boiler for NO_x control. The Ammonia Vaporizer System consists of an ammonia booster pump, a vendor package of a feed surge drum, and electric ammonia vaporizers.

P. Firewater / Fire Protection System

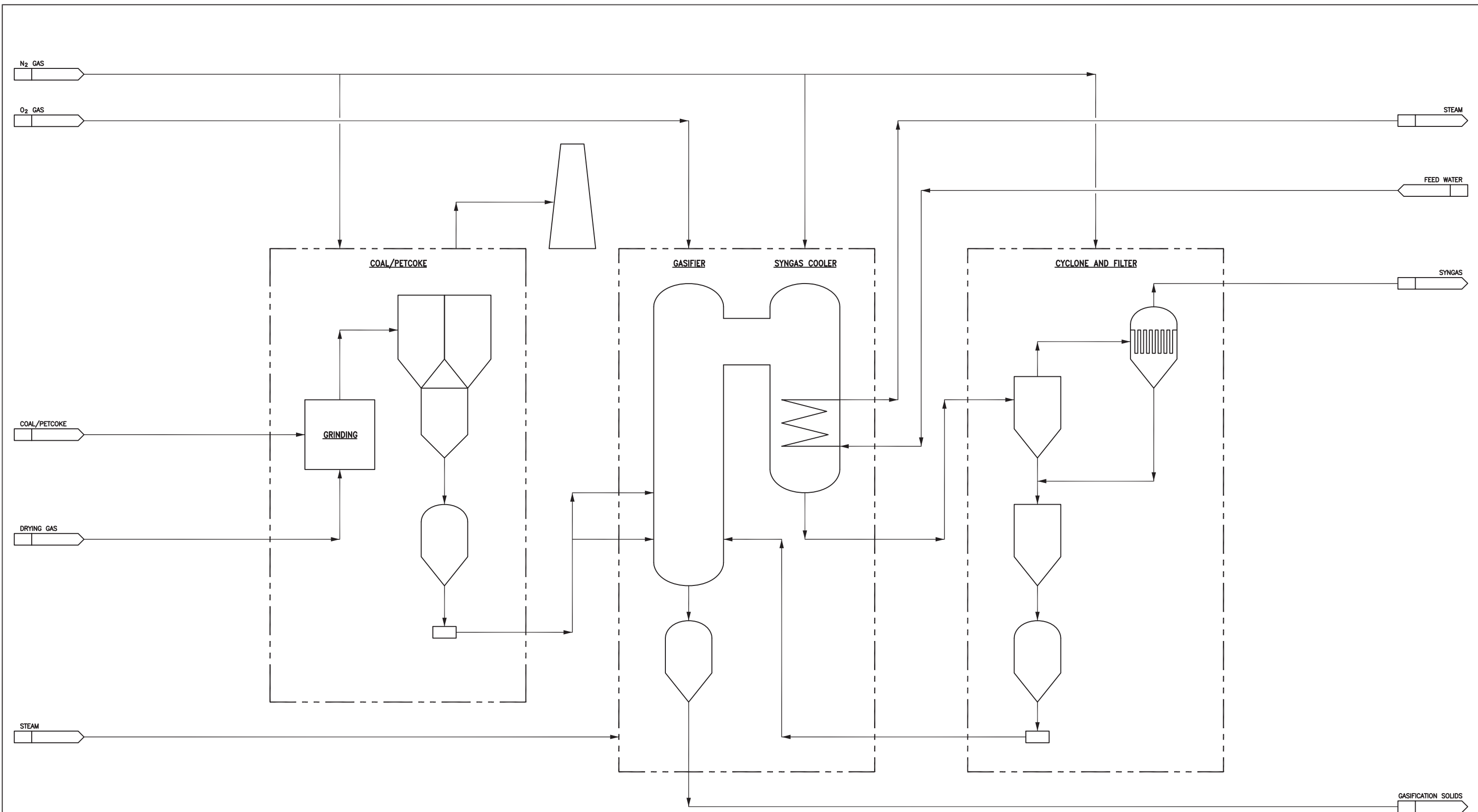
The Firewater Supply and Distribution System supports manual and automatic fire protection systems in order to minimize the likelihood, spread and duration of a fire, and ultimately to reduce the risk of injury to personnel. The Firewater Supply and Distribution System includes the systems and equipment required for protection of the process areas, utility and offsites, tank farms, and buildings.

3.8 PROCESS FLOW DIAGRAMS

The Process Flow Diagrams (PFDs) for each system illustrate the process and how the major equipment items are connected within the facility. Those identified as “representative” present non-confidential summary level information for licensed and/or proprietary systems. The following PFDs are provided in this section:

Document No.	Title
010-25-SK-0002	PROCESS FLOW DIAGRAM (REPRESENTATIVE) – GASIFICATION
020-25-PFD-0001	PROCESS FLOW DIAGRAM – SYNGAS SCRUBBER
020-25-PFD-0002	PROCESS FLOW DIAGRAM – SOUR SHIFT FIRST STAGE
020-25-PFD-0003	PROCESS FLOW DIAGRAM – SOUR SHIFT SECOND STAGE
020-25-PFD-0004	PROCESS FLOW DIAGRAM – LOW TEMPERATURE GAS COOLING (LTGC)
020-25-PFD-0005	PROCESS FLOW DIAGRAM – LOW TEMPERATURE GAS COOLING (LTGC)
020-25-PFD-0006	PROCESS FLOW DIAGRAM – MERCURY REMOVAL
020-25-PFD-0007	PROCESS FLOW DIAGRAM – AMMONIA STRIPPER
020-25-PFD-0008	PROCESS FLOW DIAGRAM – SOUR WATER STRIPPER (SWS) FEED SYSTEM
020-25-PFD-0009	PROCESS FLOW DIAGRAM – SOUR WATER STRIPPER (SWS)
020-25-PFD-0010	PROCESS FLOW DIAGRAM – START-UP GAS SUPPLY
020-25-PFD-0011	PROCESS FLOW DIAGRAM – CONDENSATE SYSTEM
031-25-SK-0001	PROCESS FLOW DIAGRAM (REPRESENTATIVE) – RECTISOL ACID GAS REMOVAL
031-25-SK-0002	PROCESS FLOW DIAGRAM (REPRESENTATIVE) – CO ₂ VENTING SYSTEM
032-25-PFD-0001	PROCESS FLOW DIAGRAM – RECTISOL REFRIGERATION - REFRIGERATION PACKAGE
032-25-PFD-0002	PROCESS FLOW DIAGRAM – RECTISOL REFRIGERATION - REFRIGERANT TO CHILLERS
032-25-SK-0003	PROCESS FLOW DIAGRAM (REPRESENTATIVE) – RECTISOL REFRIGERATION PACKAGE
040-25-PFD-0001	PROCESS FLOW DIAGRAM – CO ₂ PURIFICATION COMPRESSOR AND PURIFICATION
040-25-PFD-0002	PROCESS FLOW DIAGRAM – ENHANCED OIL RECOVERY (EOR) CO ₂ COMPRESSOR
050-25-SK-0001	PROCESS FLOW DIAGRAM (REPRESENTATIVE) - SULFUR RECOVERY UNIT
050-25-SK-0002	PROCESS FLOW DIAGRAM (REPRESENTATIVE) - TAIL GAS TREATING UNIT
051-25-PFD-0001	PROCESS FLOW DIAGRAM – CAUSTIC HANDLING & H ₂ S SCRUBBING
060-25-PFD-0001	PROCESS FLOW DIAGRAM – PSA #1 OFF-GAS COMPRESSOR
060-25-PFD-0002	PROCESS FLOW DIAGRAM – PSA #2 OFF-GAS COMPRESSOR
071-25-PFD-0001	PROCESS FLOW DIAGRAM – POWER BLOCK – GAS TURBINE, STEAM TURBINE, AND GENERATOR
072-25-PFD-0001	PROCESS FLOW DIAGRAM – POWER BLOCK – HEAT RECOVERY STEAM GENERATOR
073-25-PFD-0001	PROCESS FLOW DIAGRAM – POWER BLOCK – CONDENSATE AND BFW
073-25-PFD-0002	PROCESS FLOW DIAGRAM – POWER BLOCK - FUEL GAS AND FLUE GAS SYSTEMS
073-25-PFD-0003	PROCESS FLOW DIAGRAM – POWER BLOCK - BALANCE OF PLANT
080-25-PFD-0001	PROCESS FLOW DIAGRAM – FERTILIZER AREA PROCESS STREAMS
090-25-SK-0001	PROCESS FLOW DIAGRAM (REPRESENTATIVE) – WATER TREATMENT PLANT
090-25-SK-0002	PROCESS FLOW DIAGRAM (REPRESENTATIVE) – WATER TREATMENT PLANT
101-25-PFD-0001	PROCESS FLOW DIAGRAM – COOLING WATER SYSTEM – PROCESS BLOCK

Document No.	Title
101-25-PFD-0002	PROCESS FLOW DIAGRAM – COOLING WATER DISTRIBUTION SYSTEM – PROCESS BLOCK
102-25-PFD-0001	PROCESS FLOW DIAGRAM – COOLING WATER SYSTEM – POWER BLOCK
103-25-PFD-0001	PROCESS FLOW DIAGRAM – RECOVERED CONDENSATE SYSTEM
103-25-PFD-0002	PROCESS FLOW DIAGRAM – RECOVERED CONDENSATE SYSTEM
104-25-PFD-0001	PROCESS FLOW DIAGRAM – AUXILIARY BOILER
104-25-PFD-0002	PROCESS FLOW DIAGRAM – AUXILIARY BOILER OILY WATER SUMP
105-25-PFD-0001	PROCESS FLOW DIAGRAM – EMERGENCY DIESEL GENERATOR
106-25-PFD-0001	PROCESS FLOW DIAGRAM – PLANT & INSTRUMENT AIR SYSTEMS
106-25-PFD-0002	PROCESS FLOW DIAGRAM – PLANT & INSTRUMENT AIR DISTRIBUTION SYSTEM
107-25-PFD-0001	PROCESS FLOW DIAGRAM – GASIFICATION FLARE
107-25-PFD-0002	PROCESS FLOW DIAGRAM – RECTISOL FLARE
107-25-PFD-0003	PROCESS FLOW DIAGRAM – SRU FLARE
109-25-PFD-0001	PROCESS FLOW DIAGRAM – NATURAL GAS DISTRIBUTION SYSTEM
113-25-PFD-0001	PROCESS FLOW DIAGRAM – STORM WATER SYSTEM - L2 STORM WATER RETENTION BASIN
113-25-PFD-0002	PROCESS FLOW DIAGRAM – STORM WATER SYSTEM - L4 STORM WATER RETENTION BASIN
113-25-PFD-0003	PROCESS FLOW DIAGRAM – STORM WATER SYSTEM - L5 STORM WATER RETENTION BASIN
113-25-PFD-0004	PROCESS FLOW DIAGRAM – STORM WATER SYSTEM - L6 STORM WATER RETENTION BASIN
113-25-PFD-0005	PROCESS FLOW DIAGRAM – STORM WATER SYSTEM - L12 STORM WATER RETENTION BASIN
114-25-PFD-0001	PROCESS FLOW DIAGRAM – SOLIDS HANDLING DRAINAGE SYSTEM - WEST WASH DOWN SUMP SYSTEM
114-25-PFD-0002	PROCESS FLOW DIAGRAM – SOLIDS HANDLING DRAINAGE SYSTEM EAST WASH DOWN SUMP SYSTEM
115-25-PFD-0001	PROCESS FLOW DIAGRAM – OILY WATER SEWER - NORTH OILY WATER SUMP
115-25-PFD-0002	PROCESS FLOW DIAGRAM – OILY WATER SEWER - SOUTH OILY WATER SUMP
123-59-PFD-01	PROCESS FLOW DIAGRAM – COAL RAIL UNLOADING SYSTEM
123-59-PFD-02	PROCESS FLOW DIAGRAM – FEEDSTOCK TRUCK UNLOADING SYSTEM
123-59-PFD-03	PROCESS FLOW DIAGRAM – FEEDSTOCK STORAGE & RECLAIM SYSTEM
123-59-PFD-04	PROCESS FLOW DIAGRAM – FEEDSTOCK CRUSHING & PLANT FEED SYSTEM
124-59-PFD-01	PROCESS FLOW DIAGRAM – GASIFICATION SOLIDS MATERIAL HANDLING SYSTEM
125-25-PFD-0001	PROCESS FLOW DIAGRAM – SULFUR LIQUID STORAGE, HANDLING & RAIL / TRUCK LOADING
126-59-PFD-01	PROCESS FLOW DIAGRAM – UREA TRANSFER & STORAGE SYSTEM
126-59-PFD-02	PROCESS FLOW DIAGRAM – UREA RECLAIM & LOADOUT SYSTEM
127-25-PFD-0101	PROCESS FLOW DIAGRAM – AMMONIA VAPORIZER SYSTEM
127-25-PFD-0201	PROCESS FLOW DIAGRAM – AMMONIA LIQUID STORAGE, HANDLING & RAIL / TRUCK LOADING
127-25-PFD-0301	PROCESS FLOW DIAGRAM – UREA AMMONIUM NITRATE (UAN) LIQUID STORAGE, HANDLING & RAIL / TRUCK LOADING
128-25-PFD-0001	PROCESS FLOW DIAGRAM – FIREWATER SUPPLY



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Fluor Source Documents:

- A4UV-010-25-SK-0002 (Rev 0, 2/14/12)
- Amended AFC (08-AFC-8) Fig. 2-14 (May 2012)



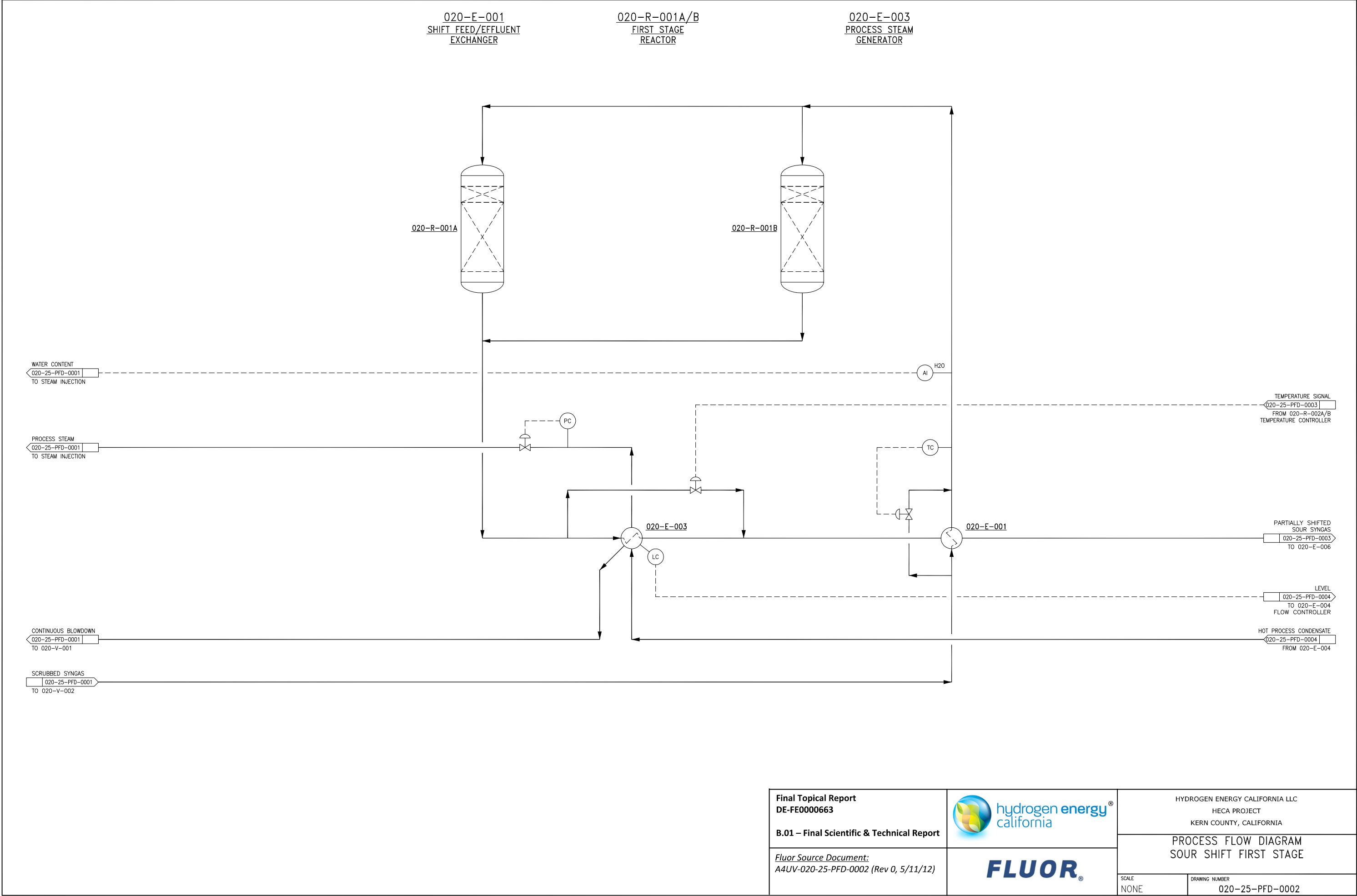
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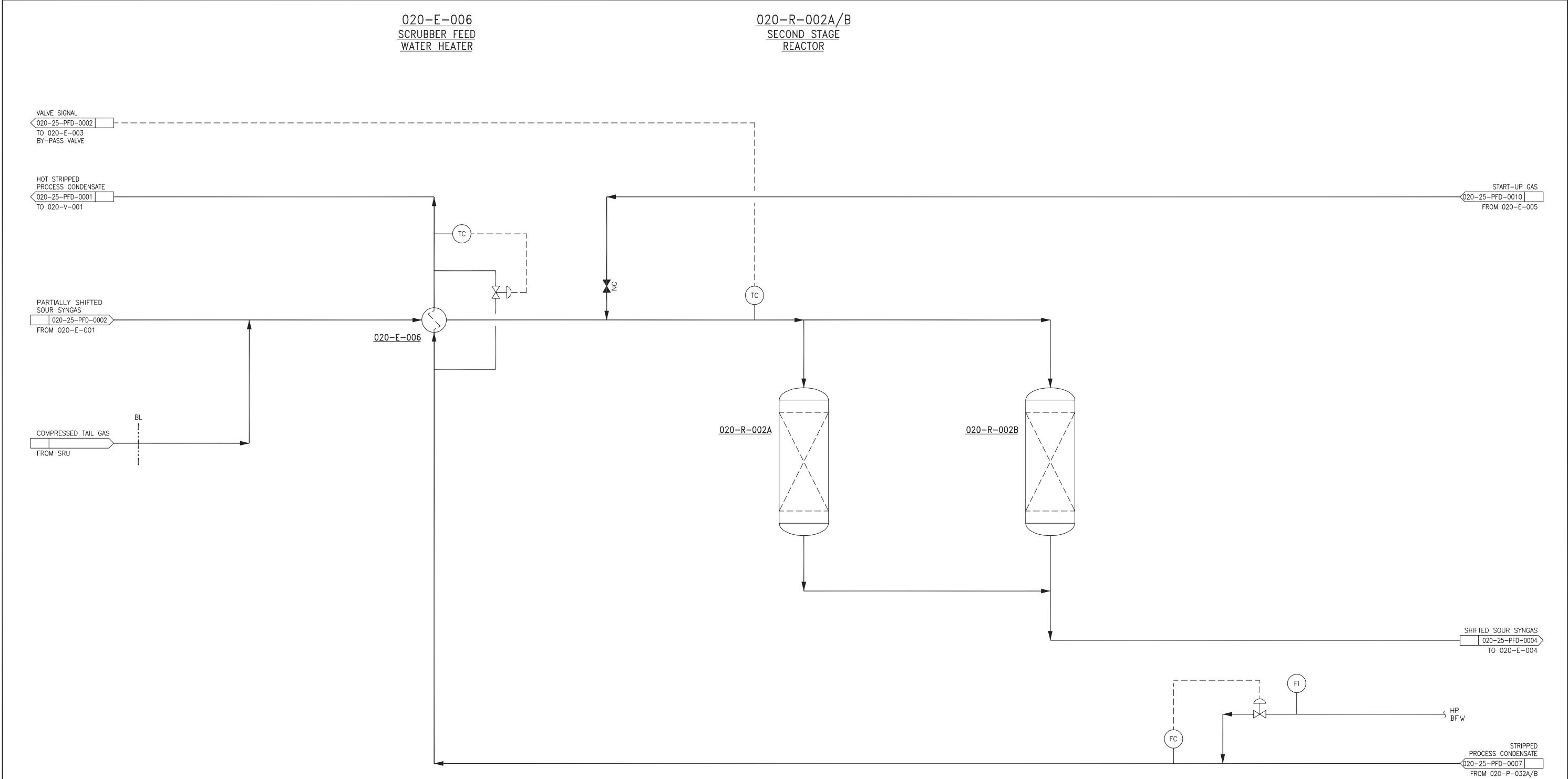
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HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM (REPRESENTATIVE)
GASIFICATION

SCALE
NONE

DRAWING NUMBER
010-25-SK-0002





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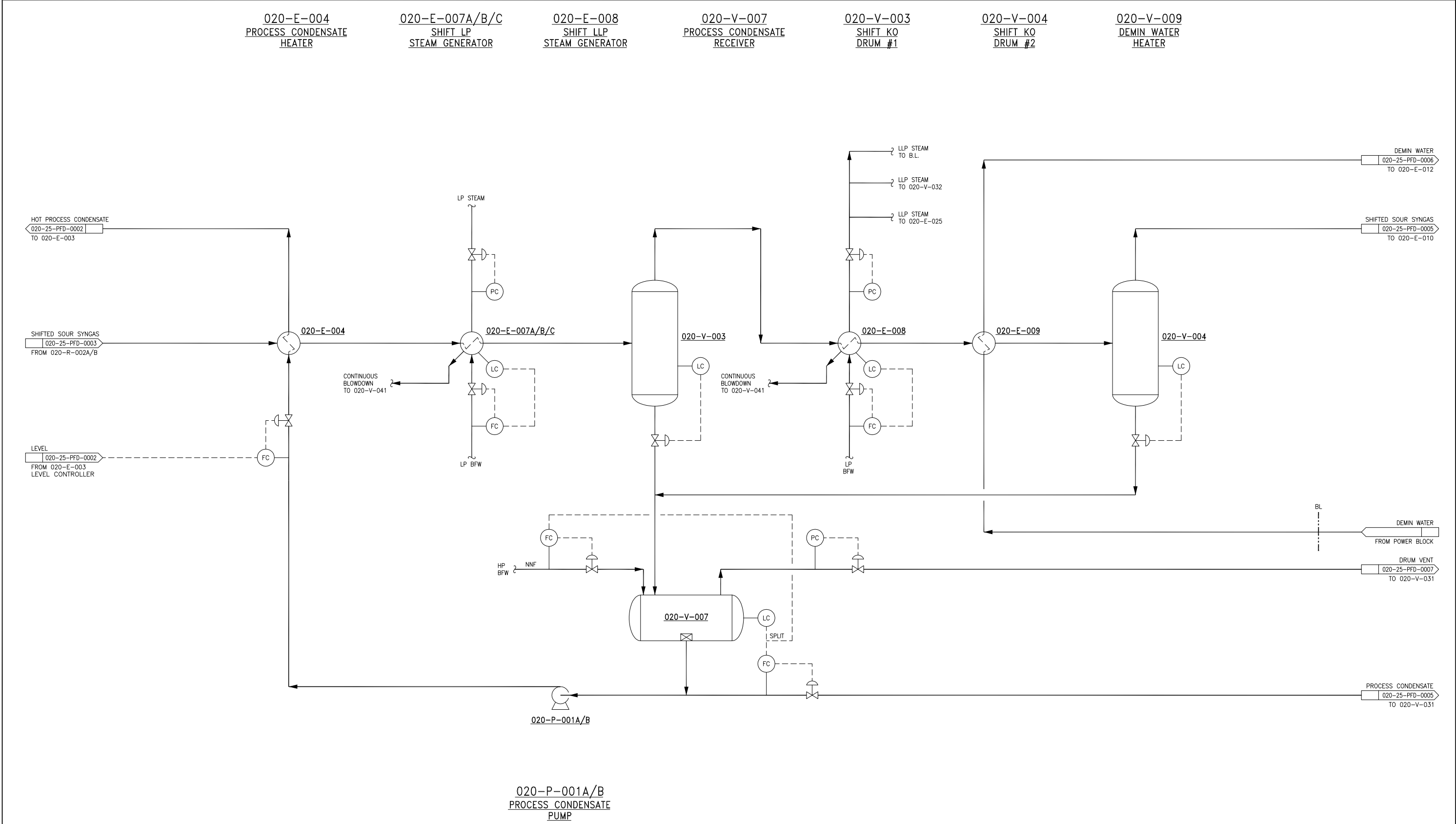
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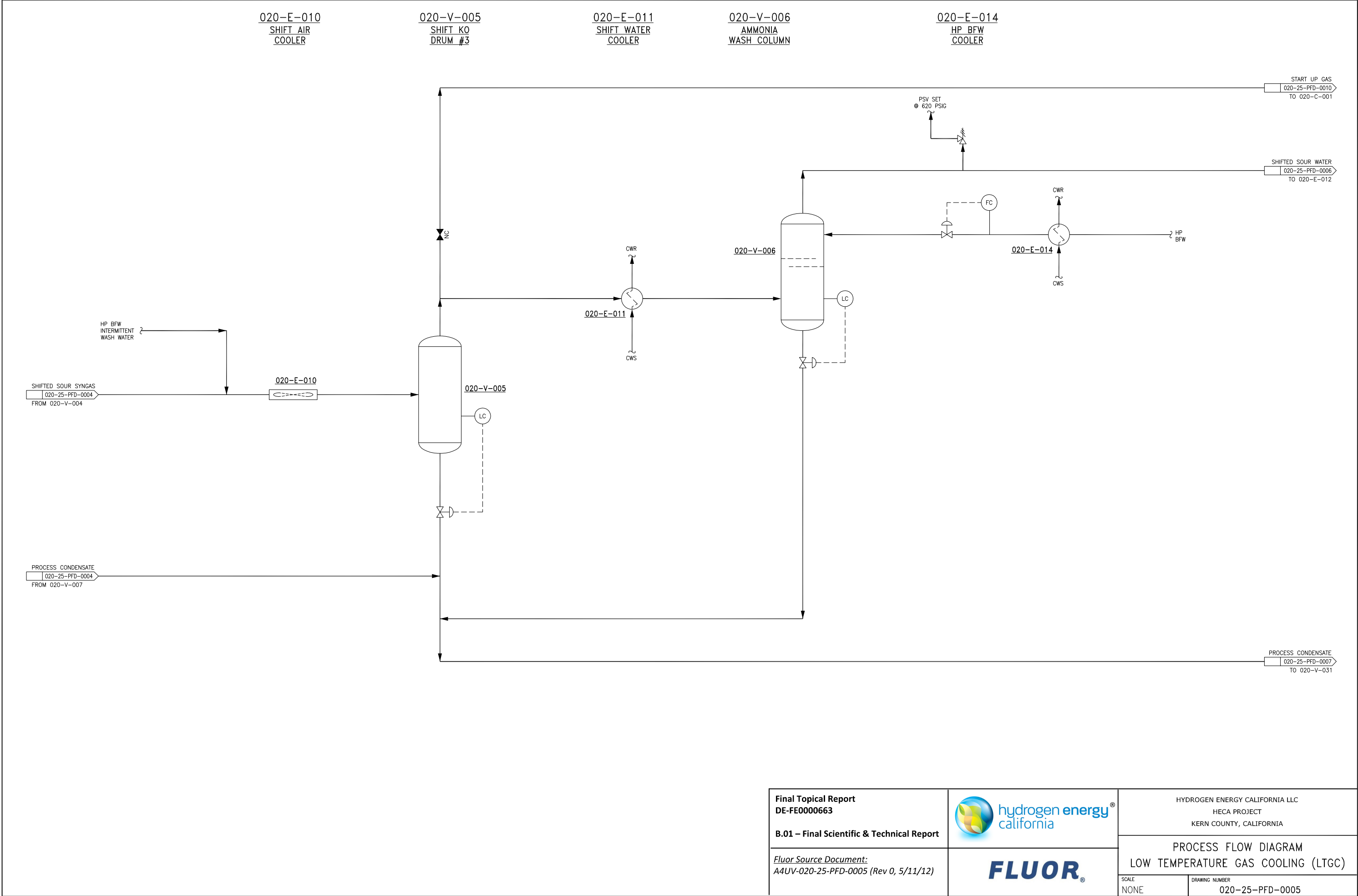
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HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
SOUR SHIFT SECOND STAGE

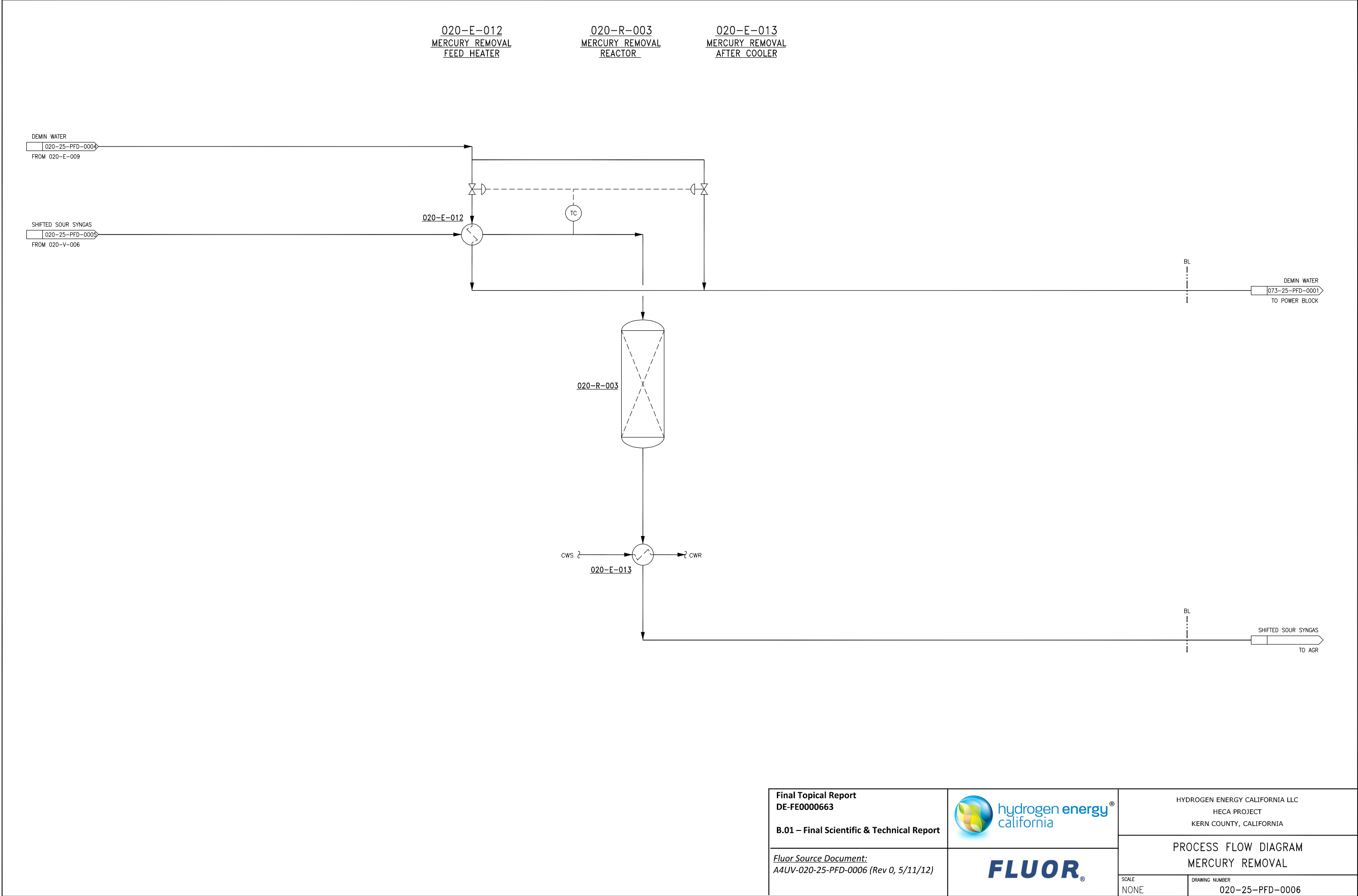
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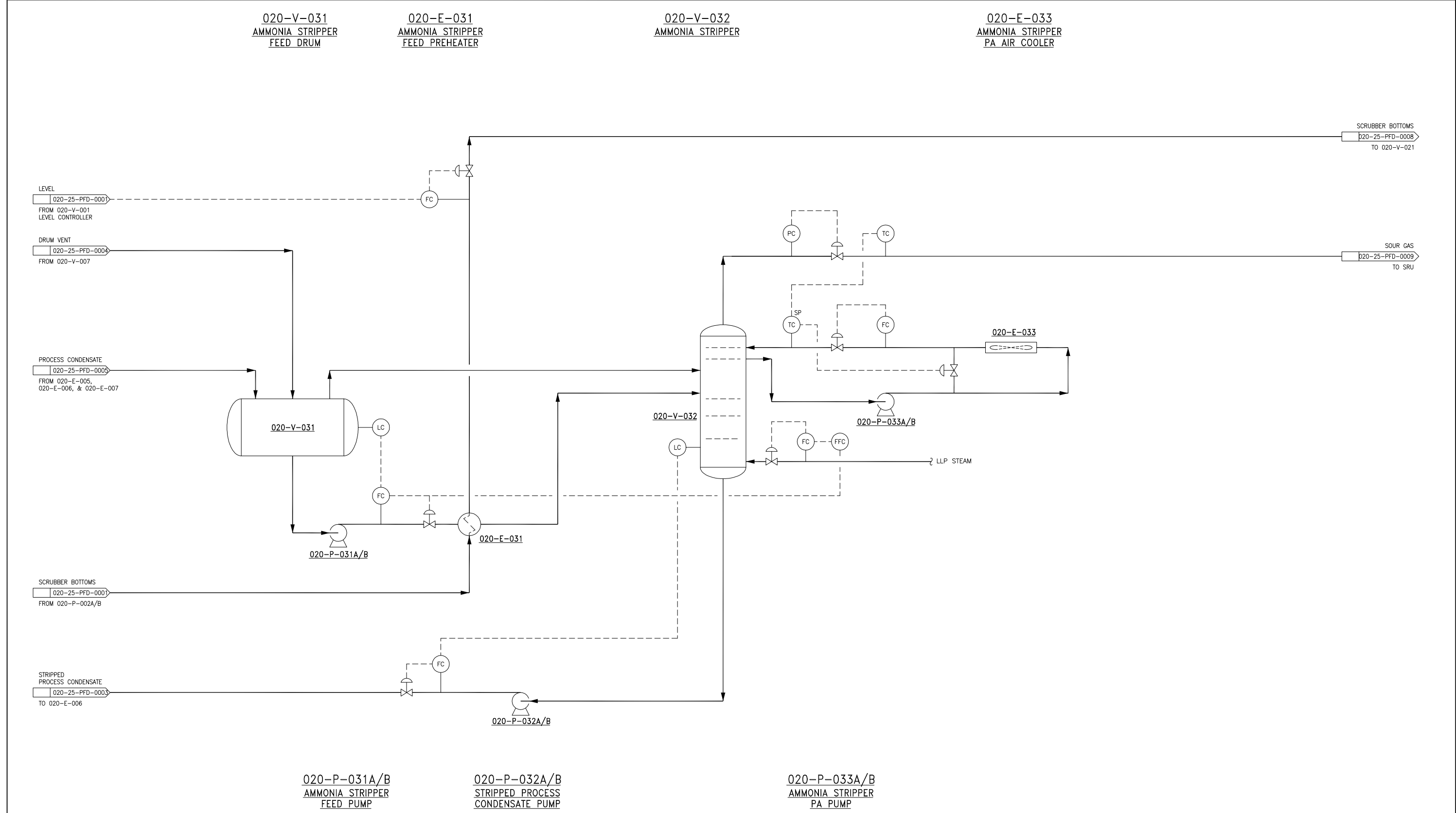




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		PROCESS FLOW DIAGRAM LOW TEMPERATURE GAS COOLING (LTGC)	
<u>Fluor Source Document:</u> A4UV-020-25-PFD-0005 (Rev 0, 5/11/12)		SCALE NONE	DRAWING NUMBER 020-25-PFD-0005



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		PROCESS FLOW DIAGRAM MERCURY REMOVAL	
Fluor Source Document: A4UV-020-25-PFD-0006 (Rev 0, 5/11/12)		SCALE NONE	DRAWING NUMBER 020-25-PFD-0006



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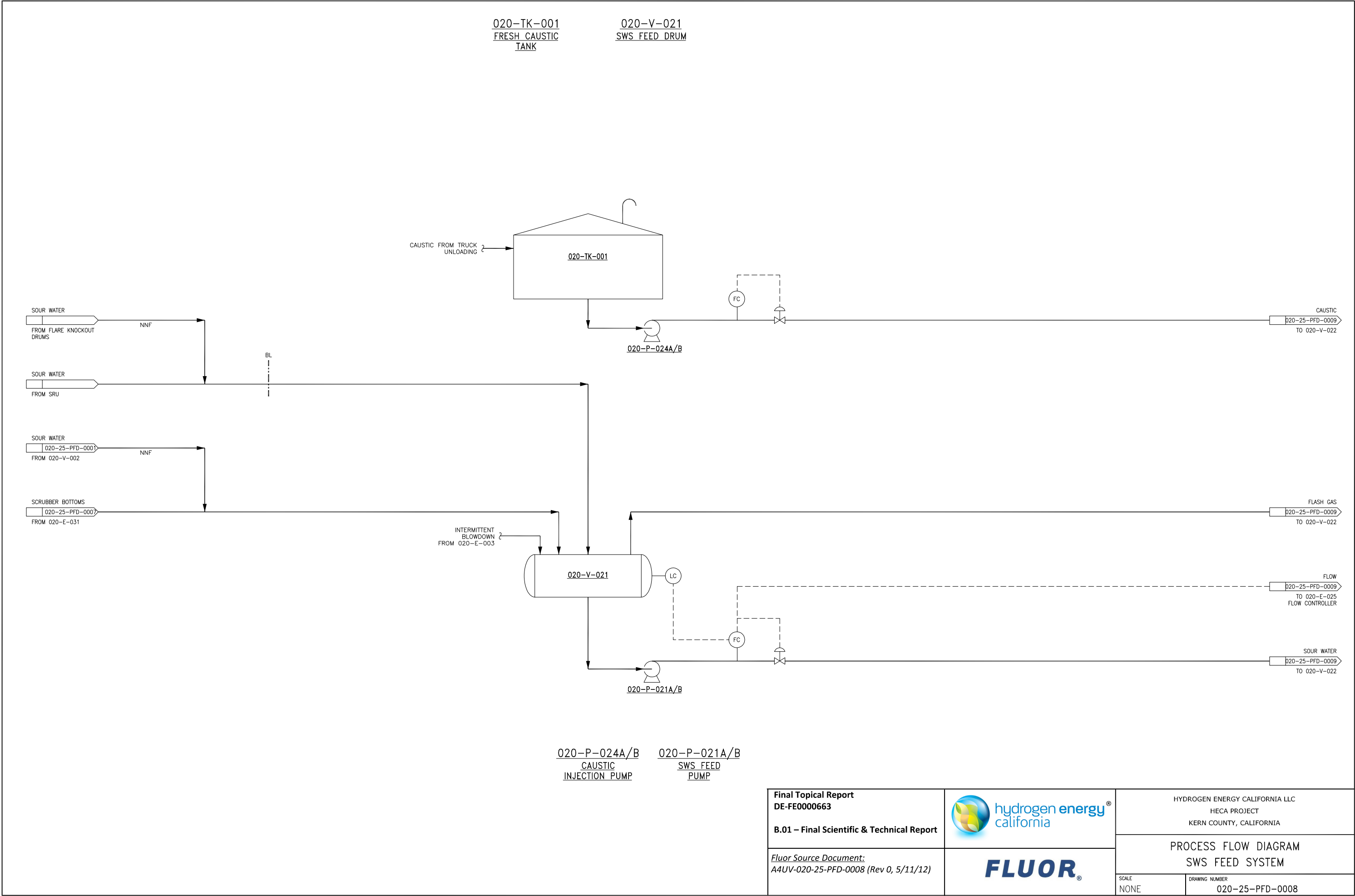
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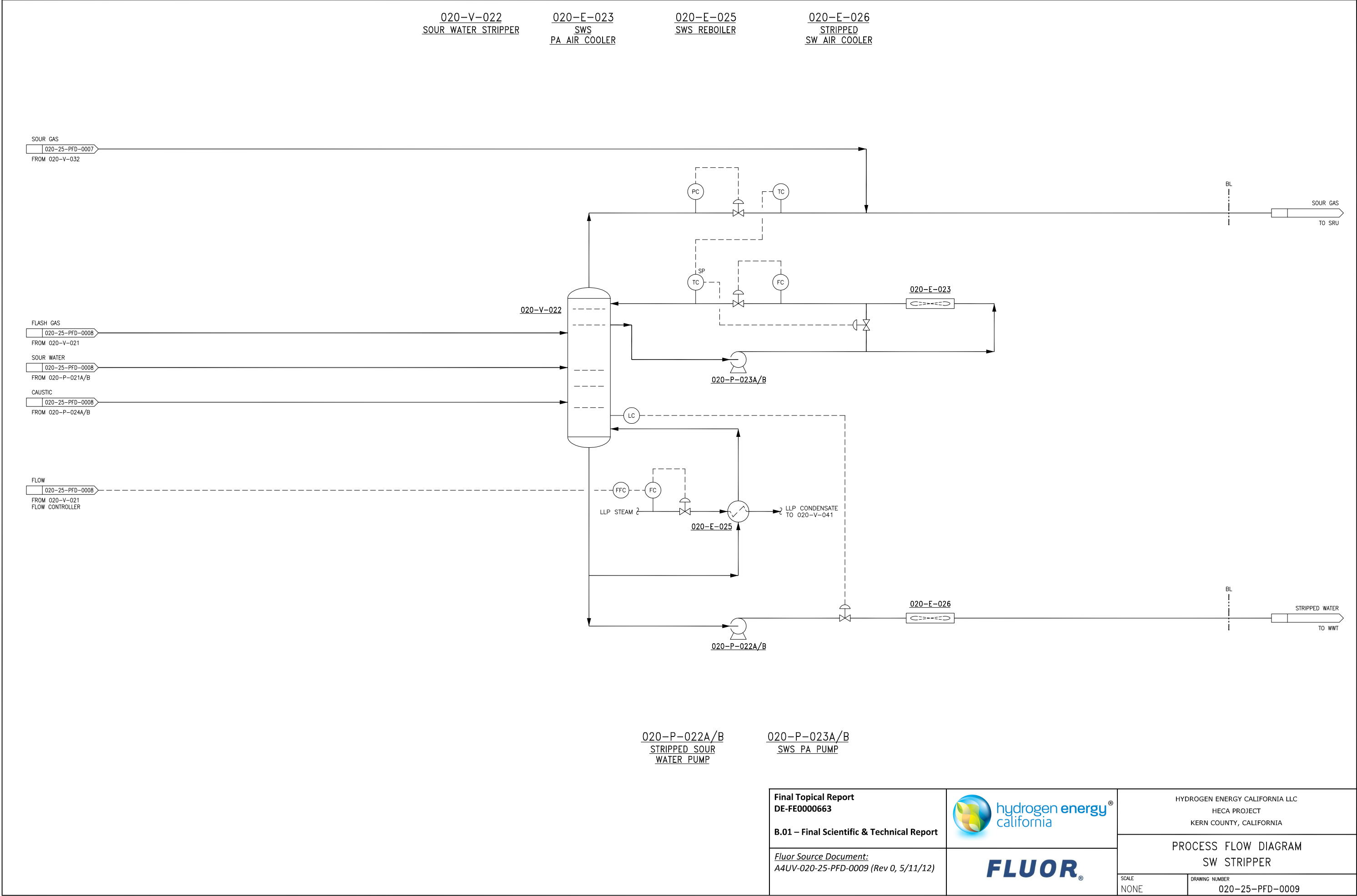
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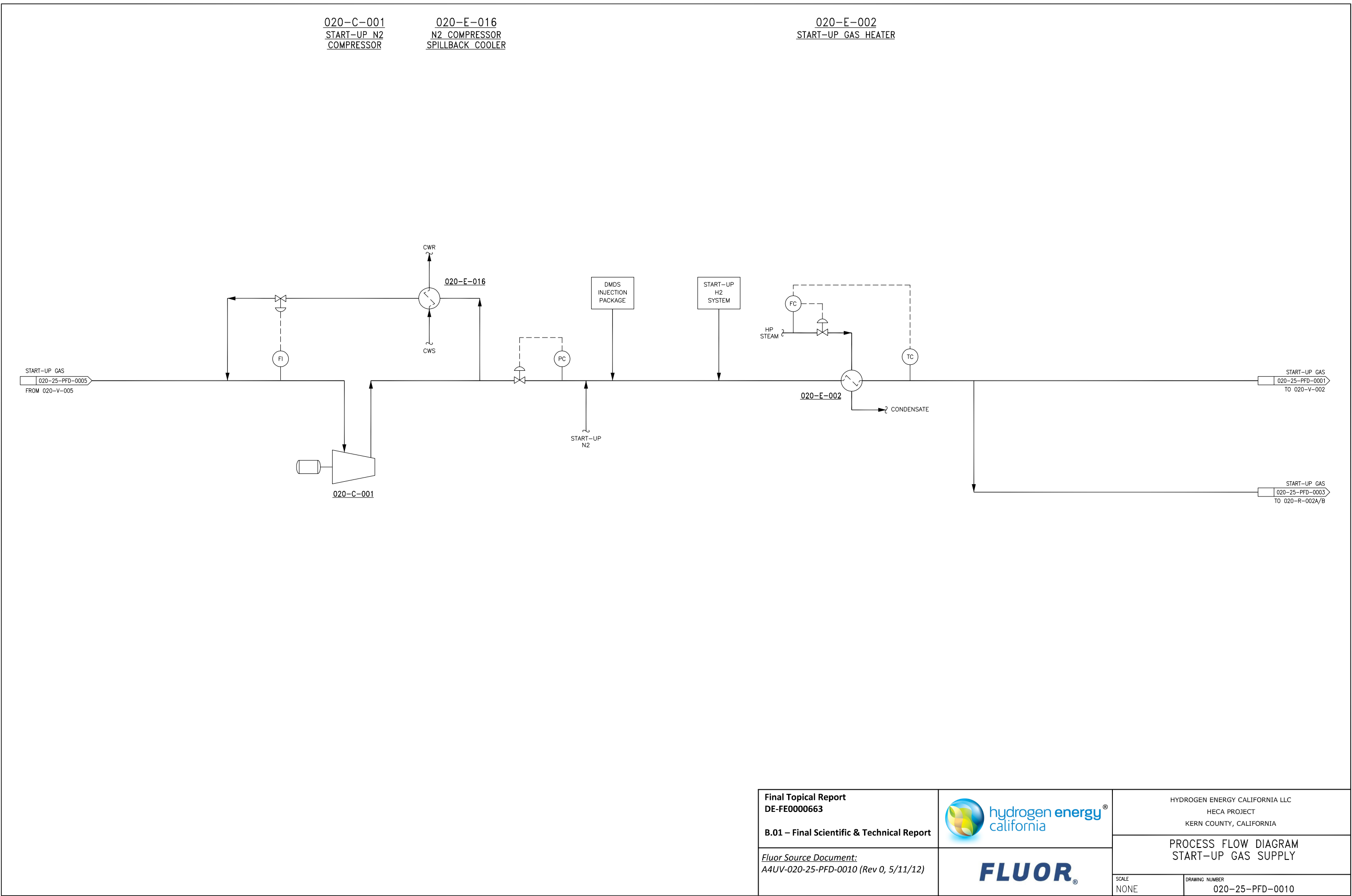
PROCESS FLOW DIAGRAM
AMMONIA STRIPPER

SCALE
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DRAWING NUMBER
020-25-PFD-0007







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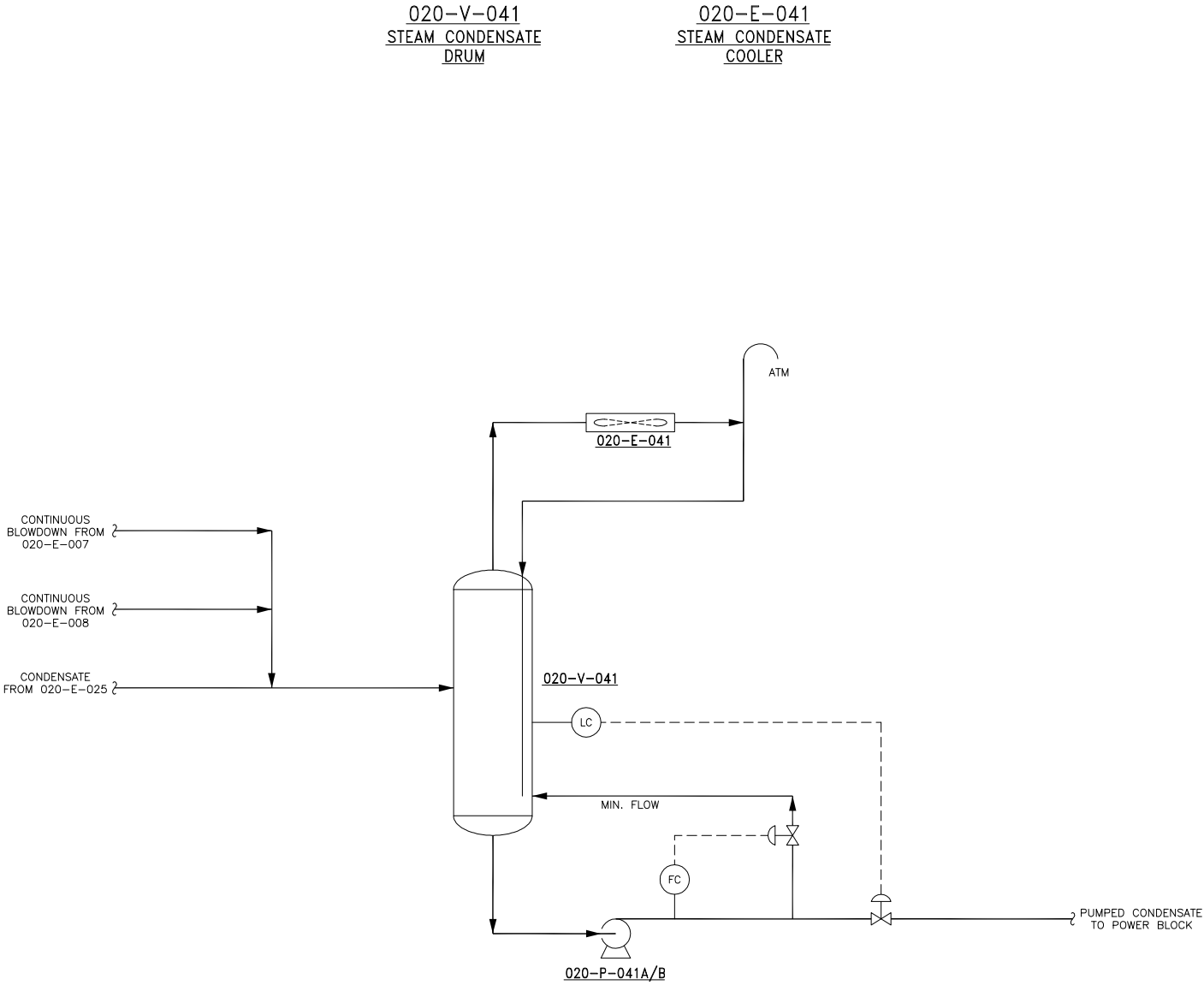
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PROCESS FLOW DIAGRAM
START-UP GAS SUPPLY

SCALE
NONE

DRAWING NUMBER
020-25-PFD-0010



020-P-041A/B
STEAM CONDENSATE
PUMP

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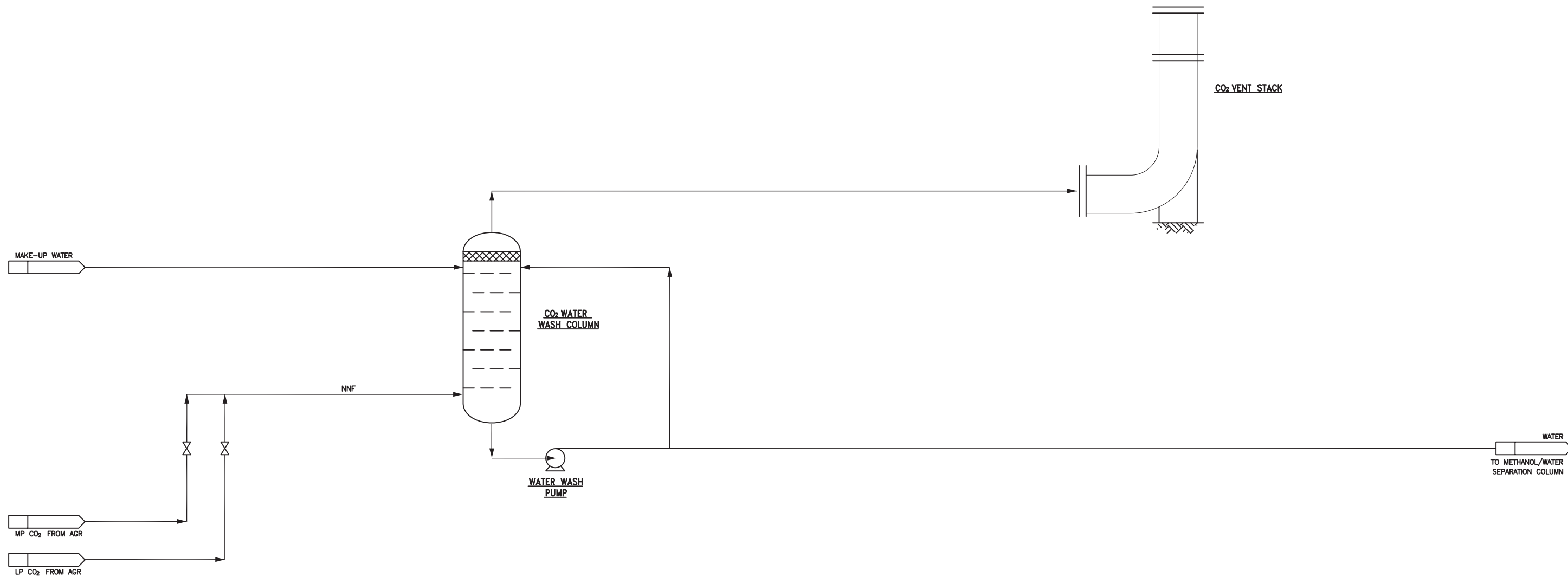
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PROCESS FLOW DIAGRAM
CONDENSATE SYSTEM

SCALE
NONE

DRAWING NUMBER
020-25-PFD-0011



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Fluor Source Documents:

- A4UV-030-25-SK-0002 (Rev 0, 2/2/12)
- Amended AFC (08-AFC-8) Fig. 2-39 (May 2012)

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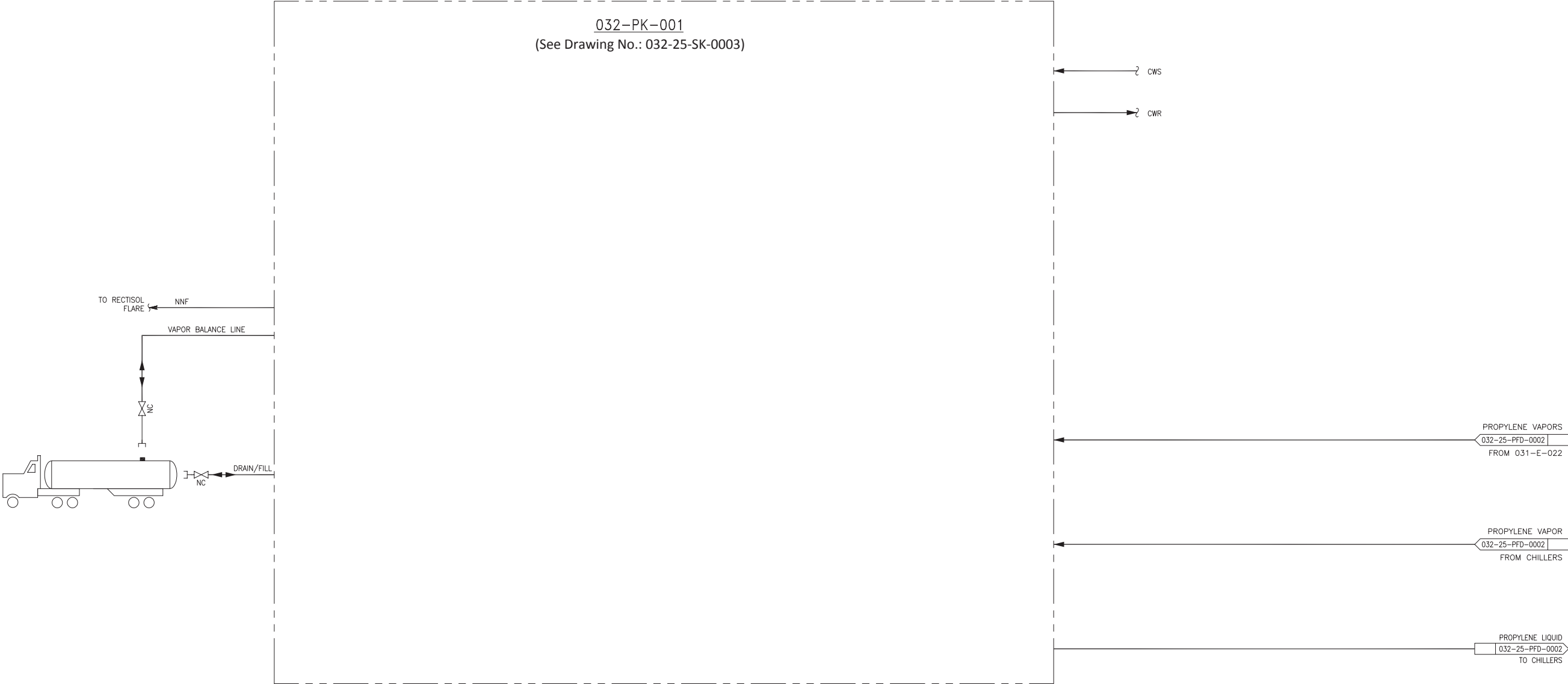
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PROCESS FLOW DIAGRAM (REPRESENTATIVE)
CO₂ VENTING SYSTEM

SCALE
NONE

DRAWING NUMBER
031-25-SK-0002

032-PK-001
AGR
REFRIGERATION PACKAGE



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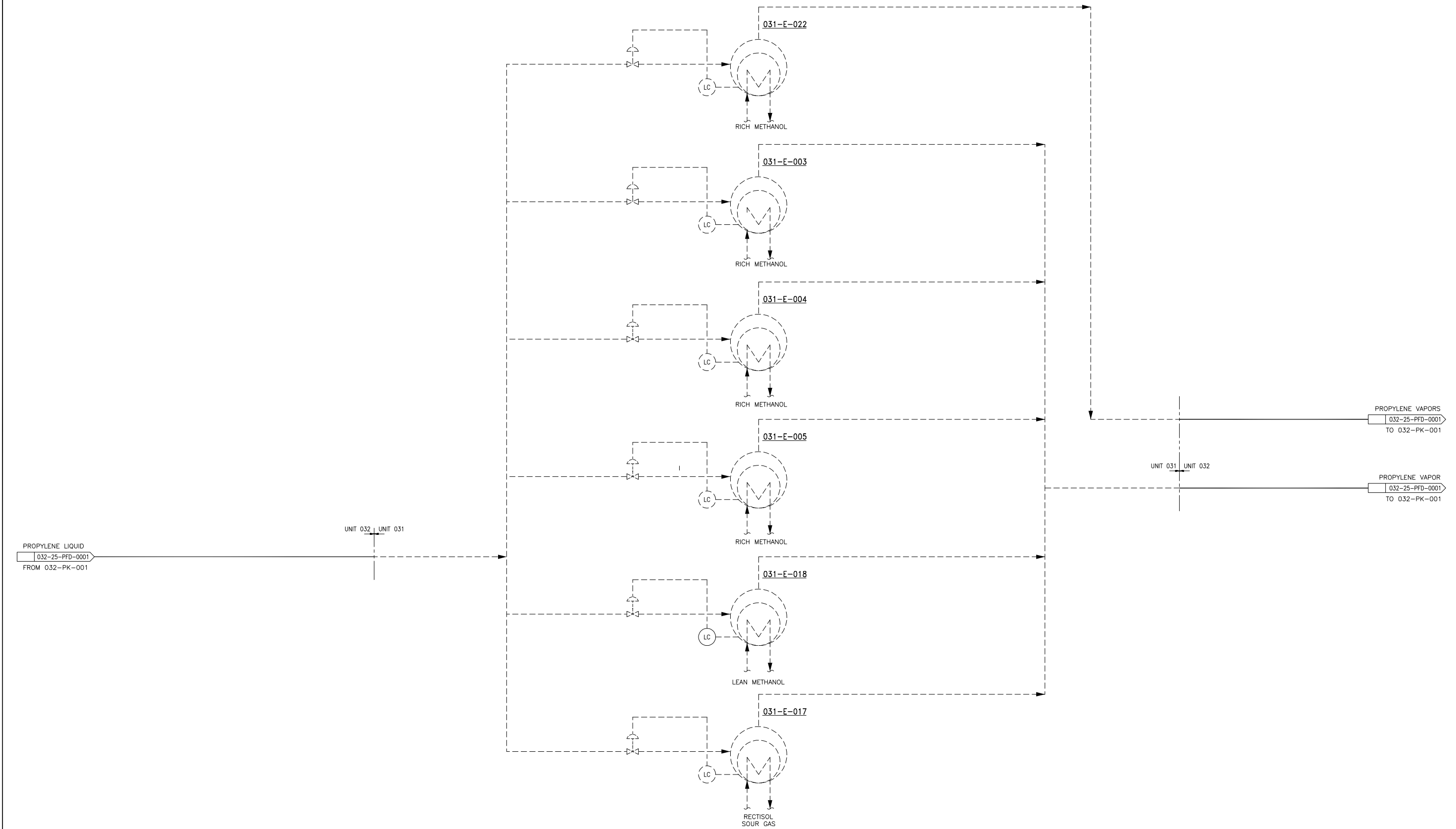
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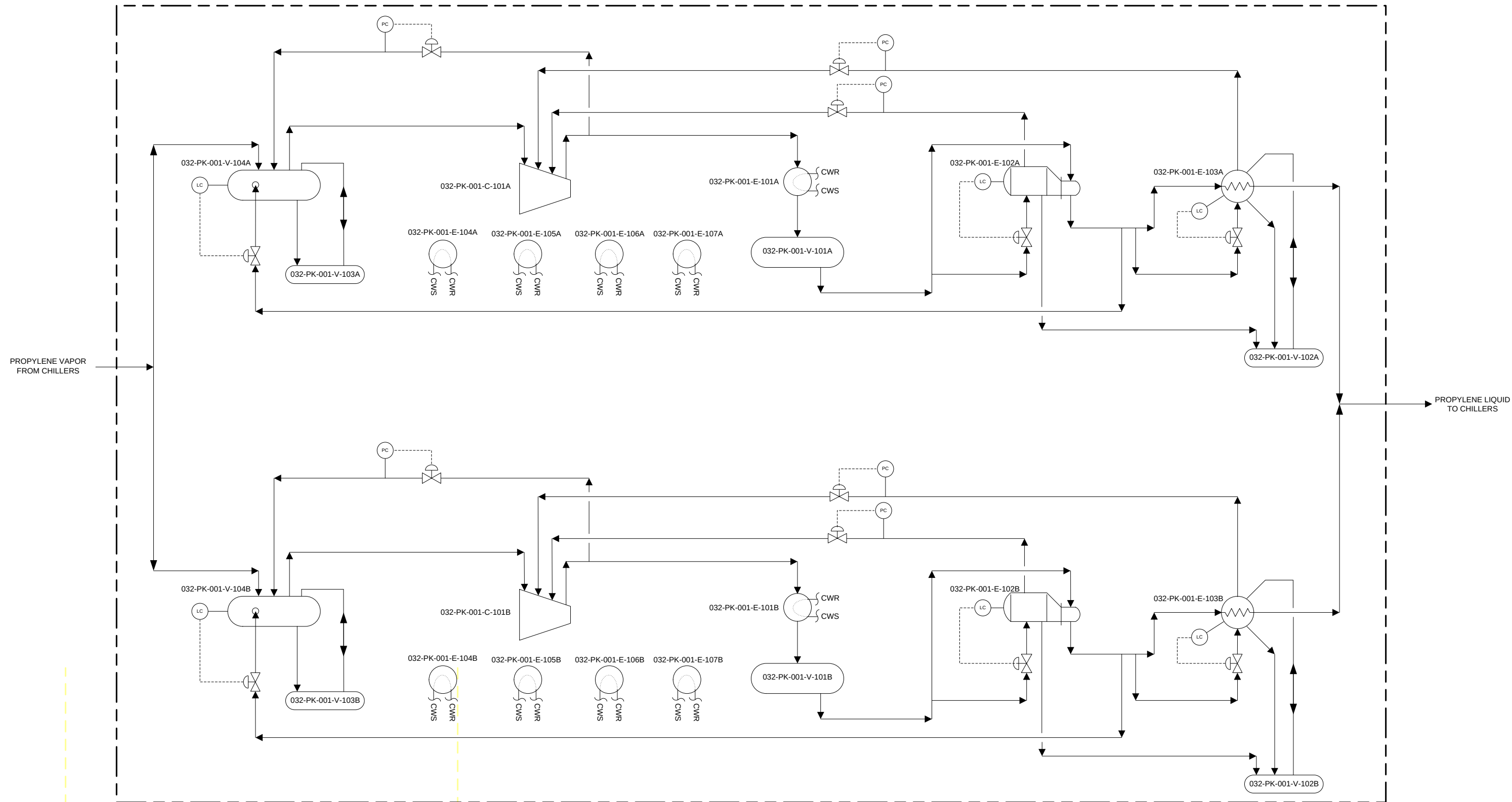
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SCALE
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DRAWING NUMBER
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		PROCESS FLOW DIAGRAM RECTISOL REFRIGERATION REFRIGERANT TO CHILLERS	
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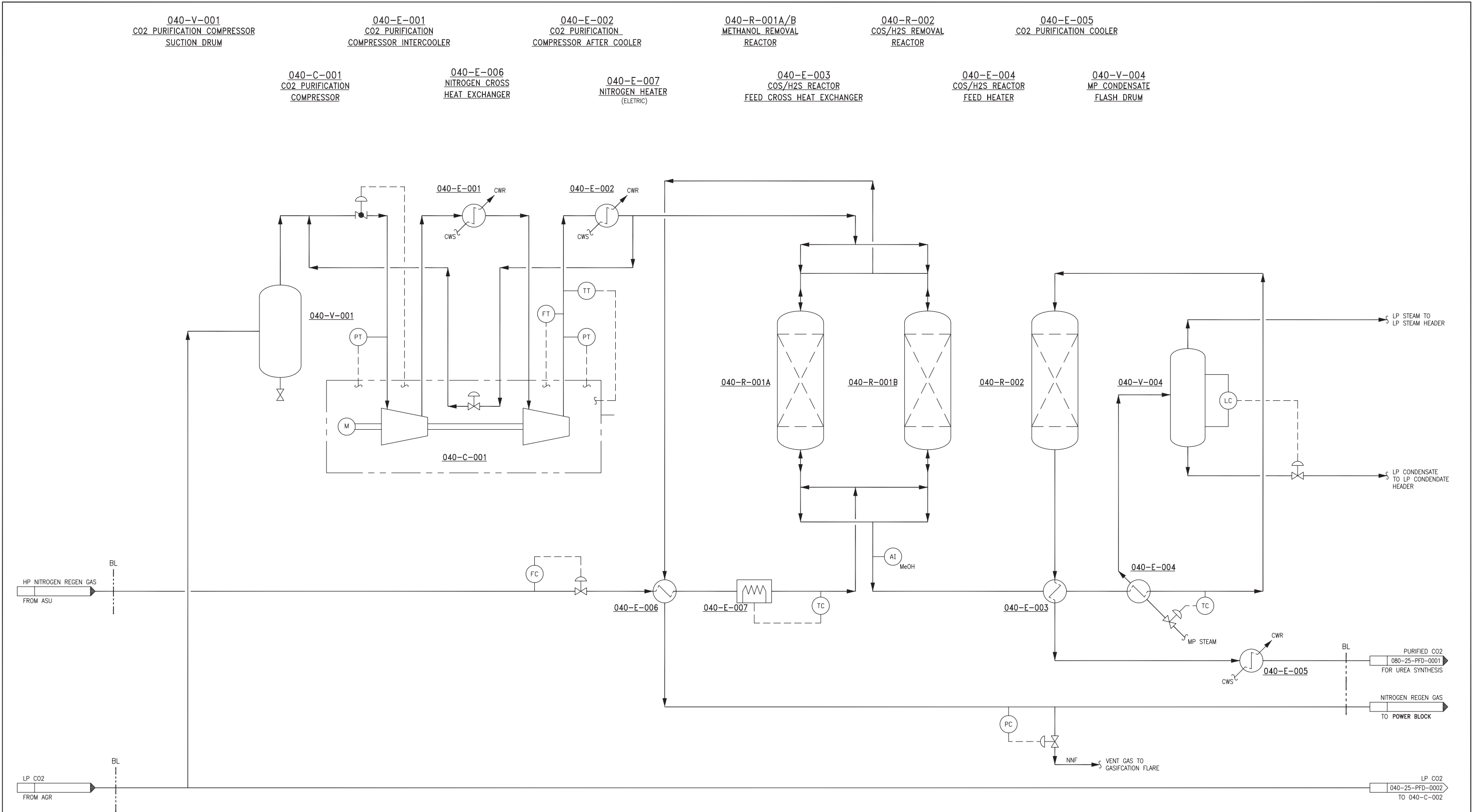


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		PROCESS FLOW DIAGRAM (REPRESENTATIVE) RECTISOL REFRIGERATION REFRIGERATION PACKAGE	
		SCALE NONE	DRAWING NUMBER 032-25-SK-0003

Fluor Source Documents:

- A4UV-032-25-SK-0001 (Rev D, 9/18/12)
- A4UV-032-25-SK-0002 (Rev D, 9/18/12)

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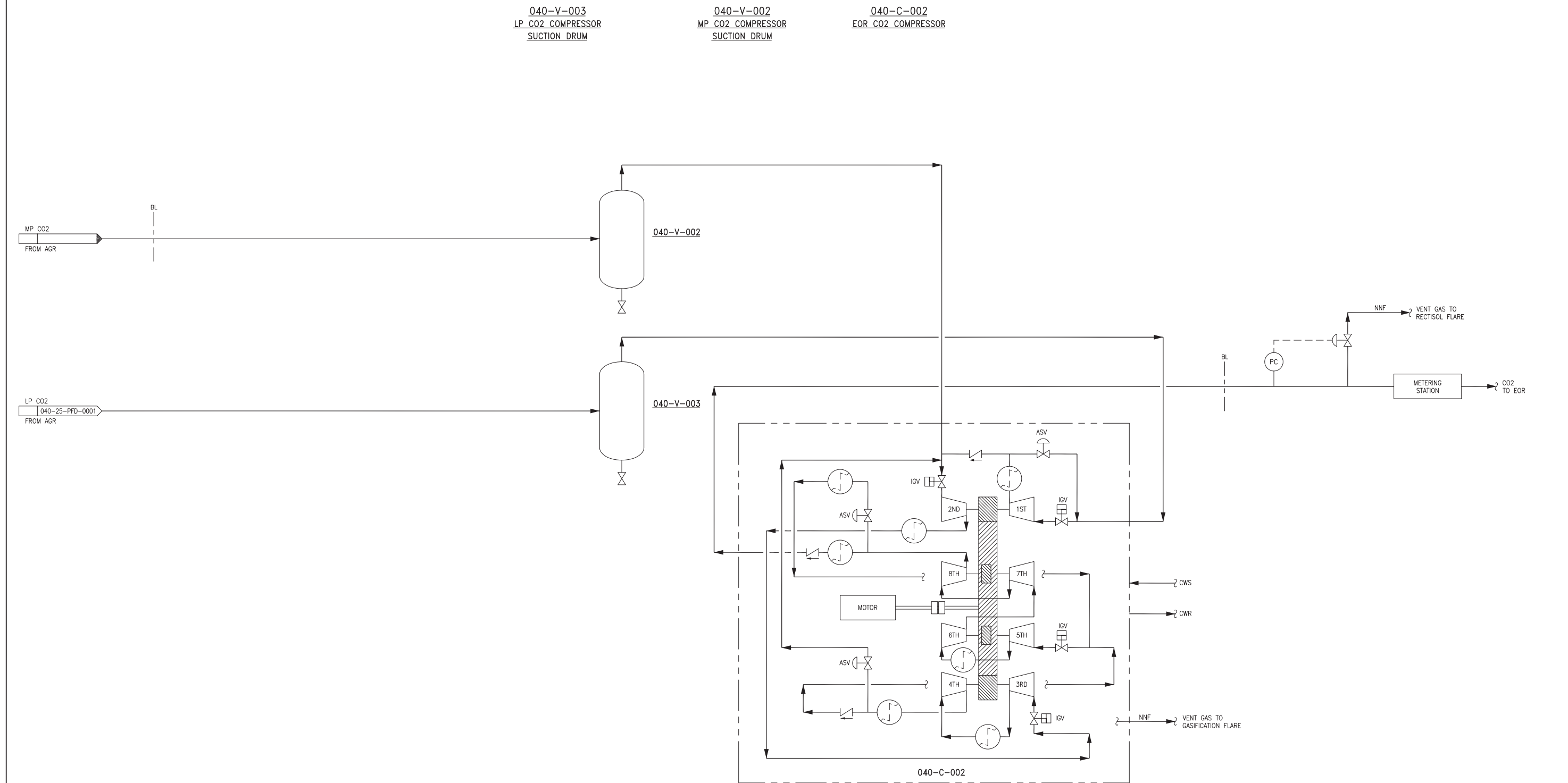
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KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
CO2 COMPRESSION AND PURIFICATION
CO2 PURIFICATION COMPRESSOR AND PURIFICATION

CALE
NONE

DRAWING NUMBER
040-25-PFD-0001



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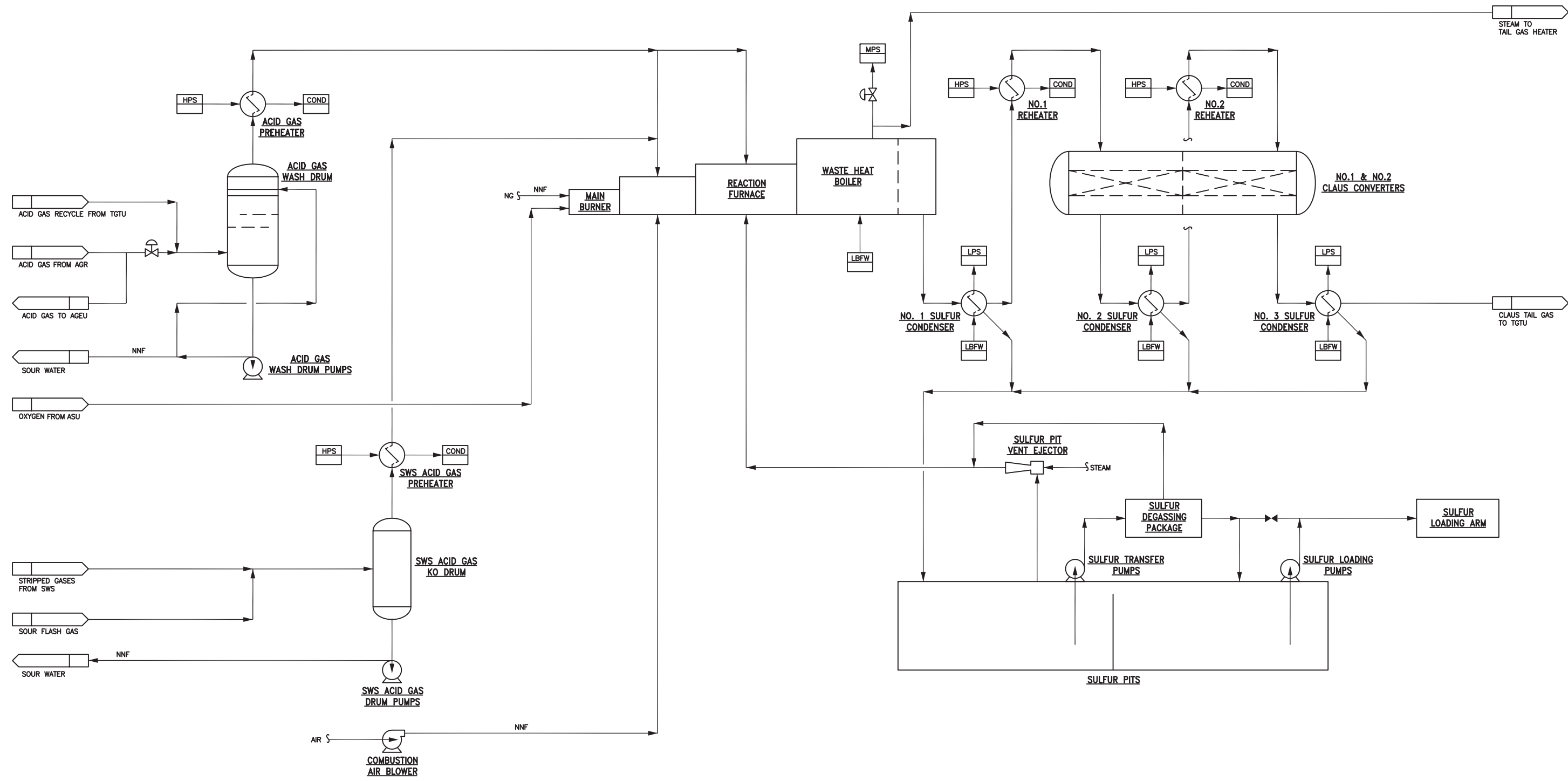
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HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

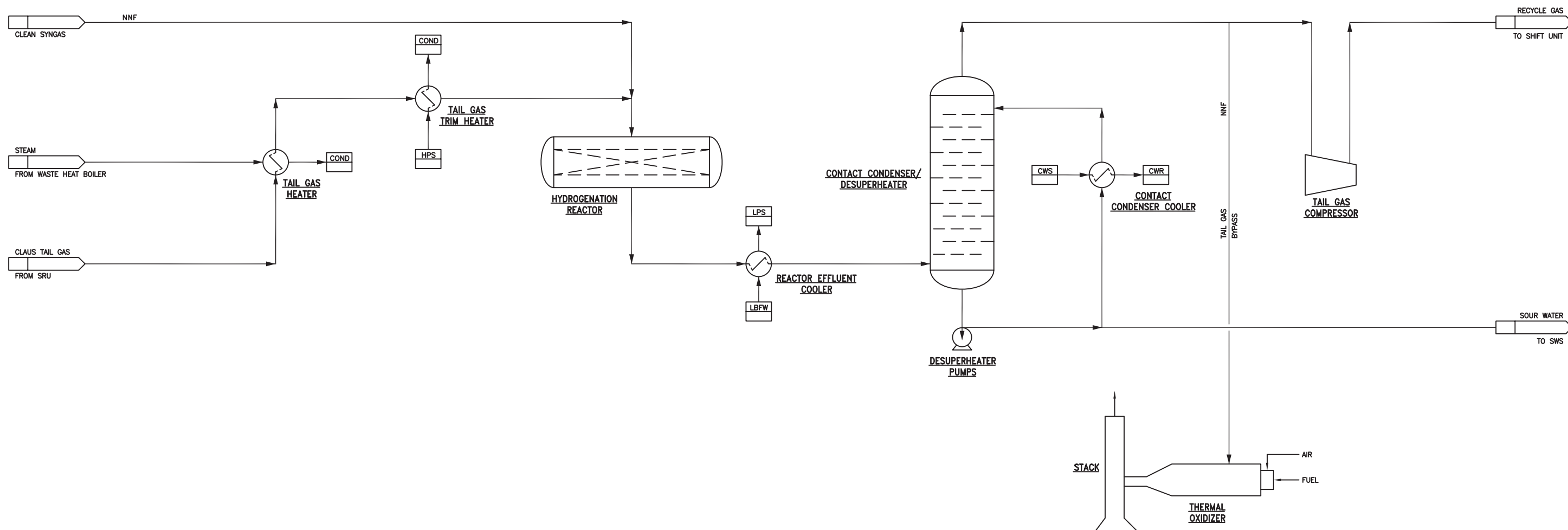
PROCESS FLOW DIAGRAM
CO2 COMPRESSION AND PURIFICATION
EOR CO2 COMPRESSOR

SCALE
NONE

DRAWING NUMBER
040-25-PFD-0002



Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report <i>Fluor Source Documents:</i> - A4UV-050-25-SK-0001 (Rev 0, 2/14/12) - Amended AFC (08-AFC-8) Fig. 2-36 (May 2012)	 	HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA	
		PROCESS FLOW DIAGRAM (REPRESENTATIVE) SULFUR RECOVERY UNIT	
		SCALE NONE	DRAWING NUMBER 050-25-SK-0001



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Fluor Source Documents:

- A4UV-050-25-SK-0002 (Rev 0, 2/14/12)
- Amended AFC (08-AFC-8) Fig. 2-37 (May 2012)



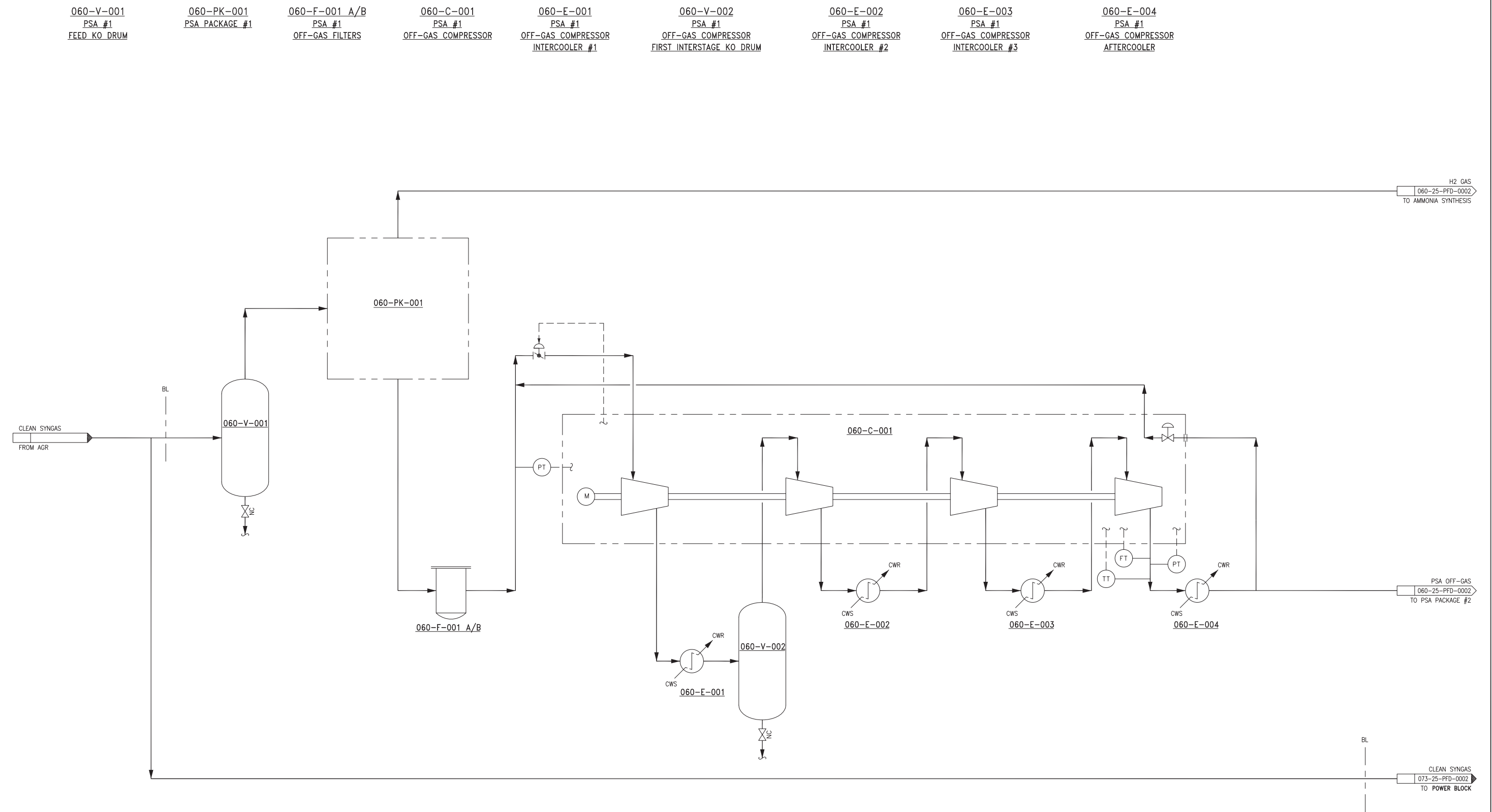
FLUOR

HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM (REPRESENTATIVE)
TAIL GAS TREATING UNIT

SCALE
NONE

DRAWING NUMBER
050-25-SK-0002



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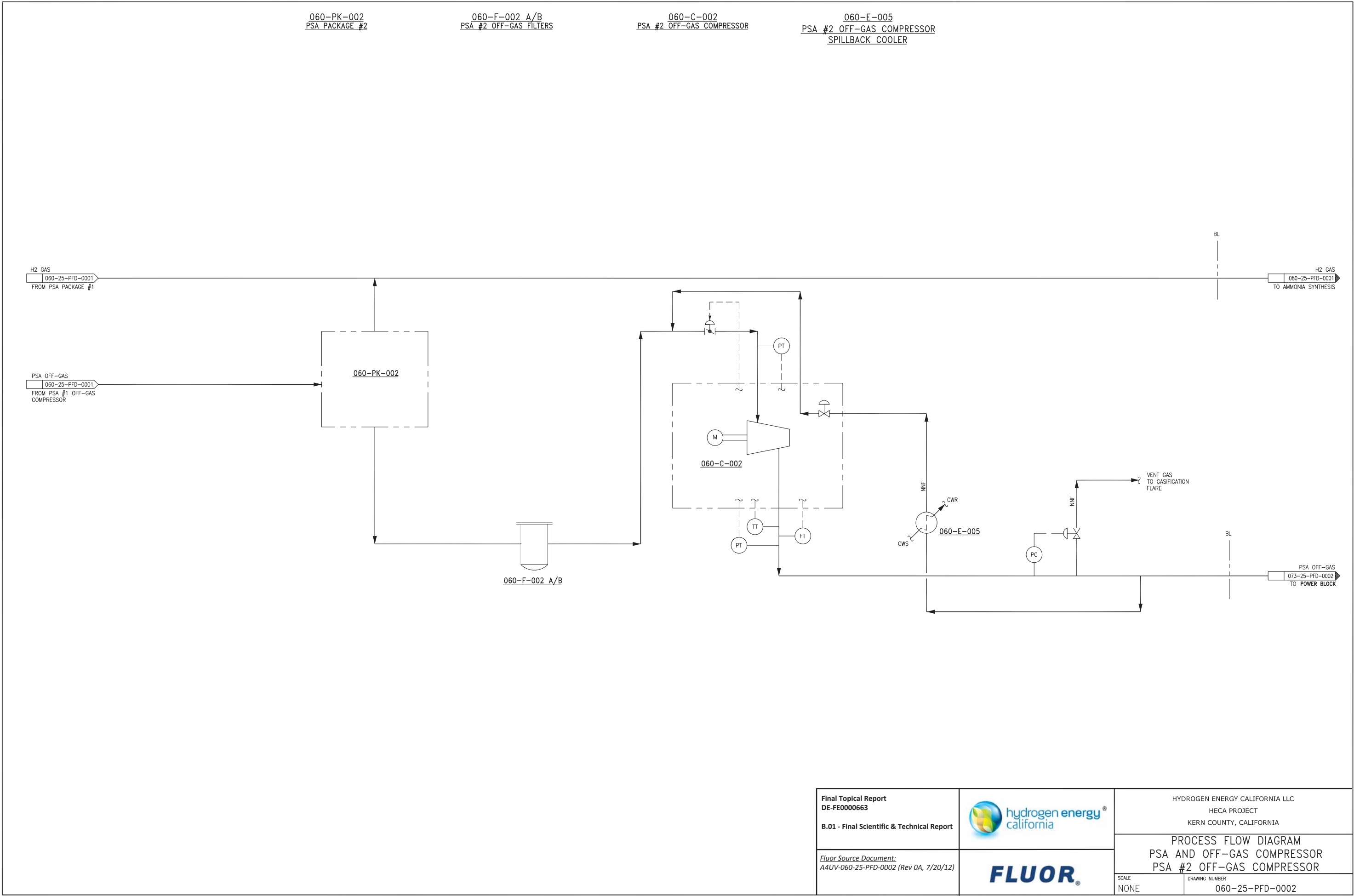
PROCESS FLOW DIAGRAM
PSA AND OFF-GAS COMPRESSION
PSA #1 OFF-GAS COMPRESSOR

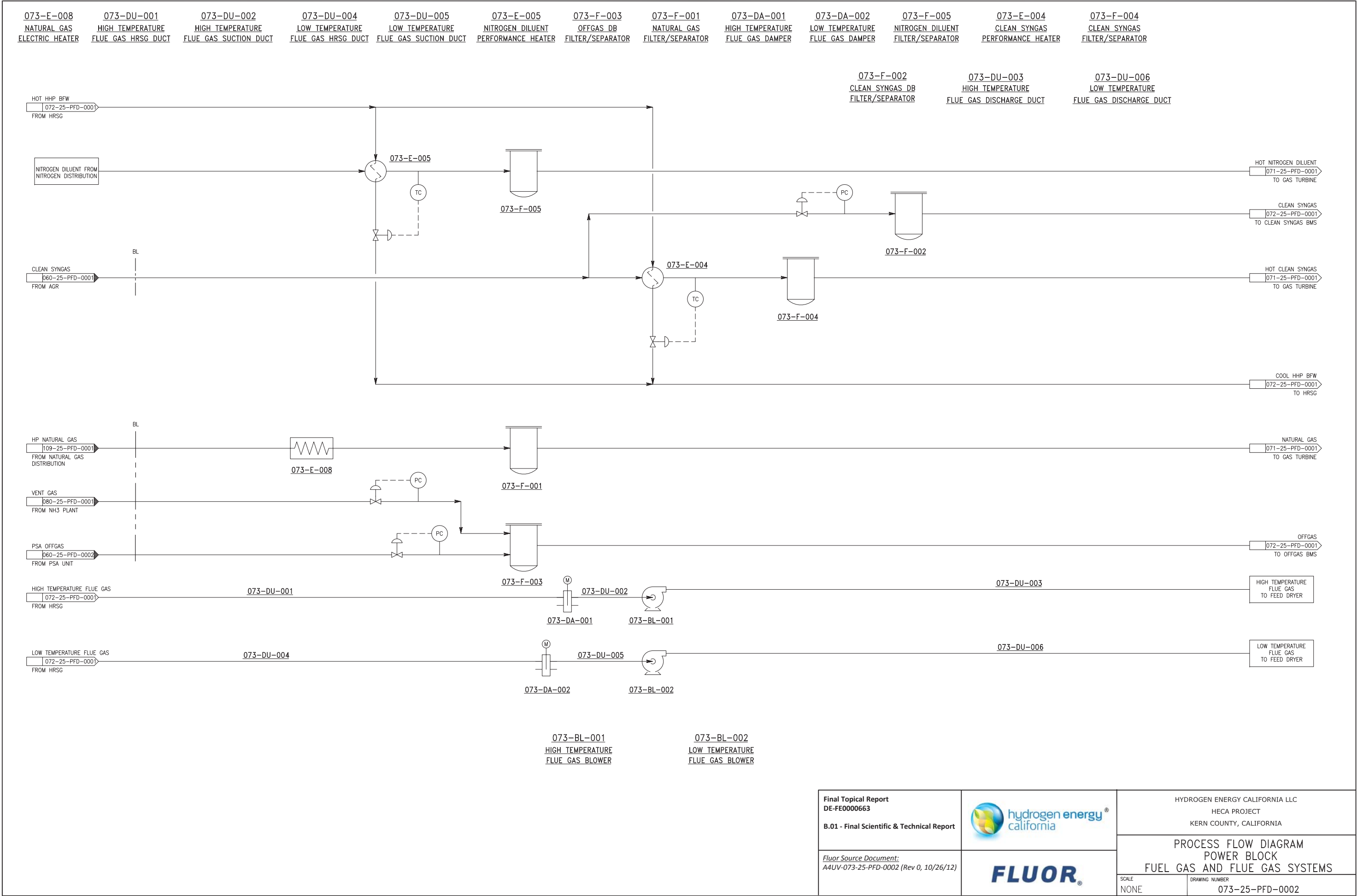
SCALE
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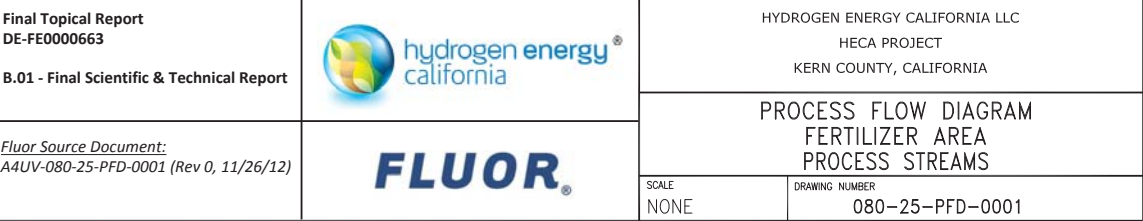
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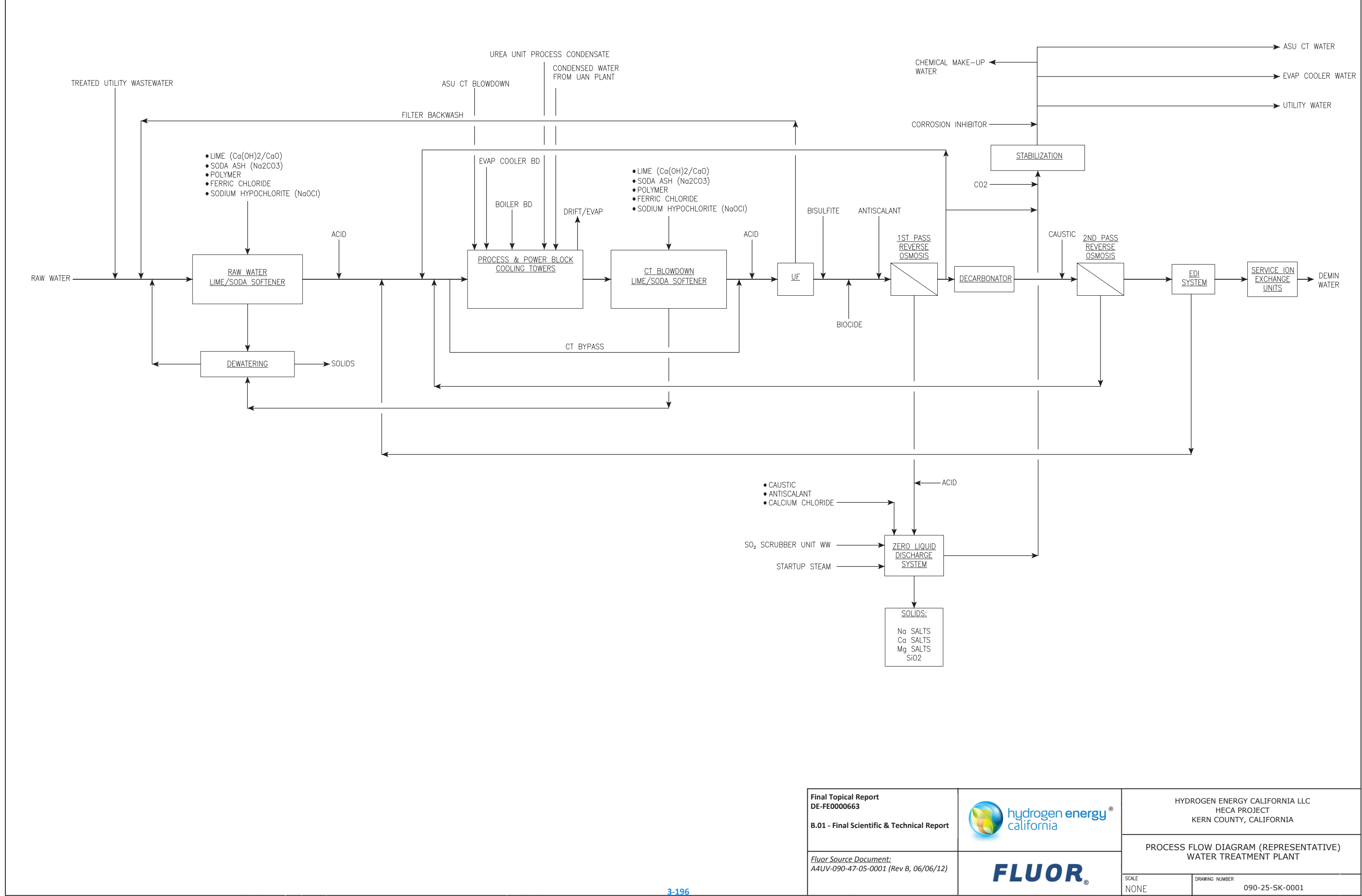
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Fluor Source Document:
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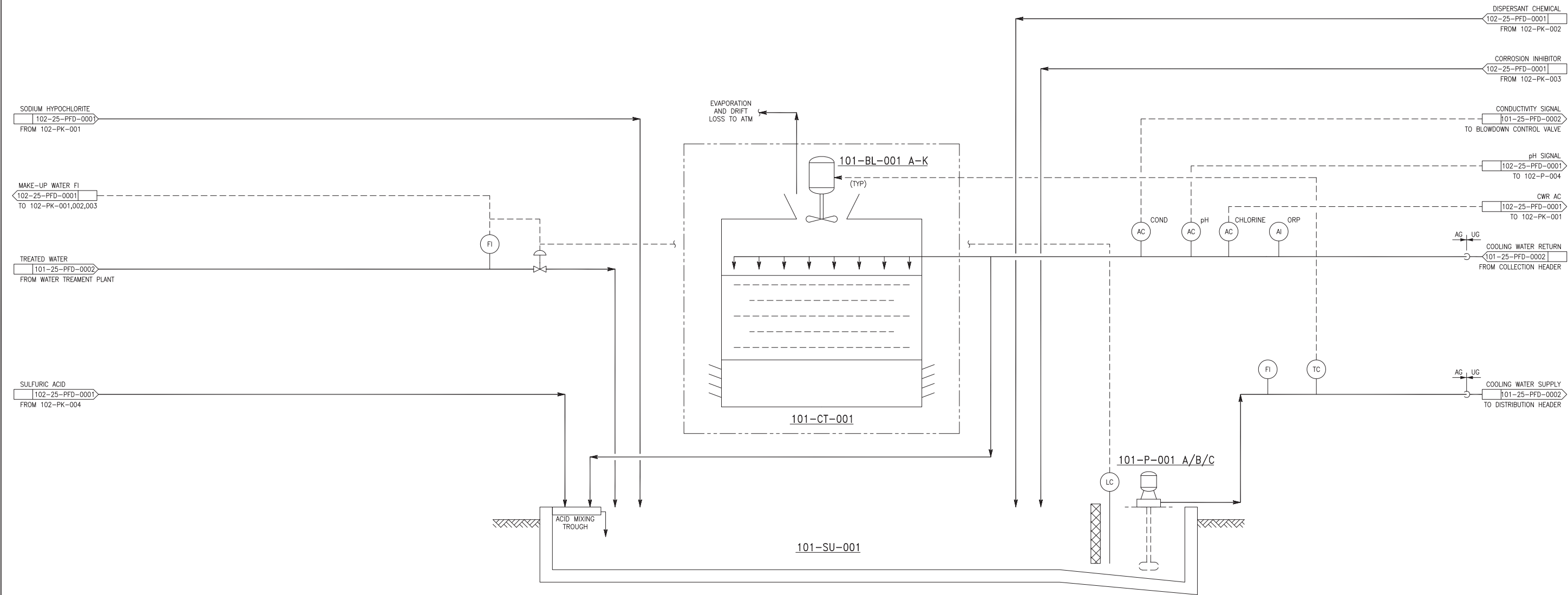


101-CT-001
PROCESS BLOCK
COOLING TOWER

101-SU-001
PROCESS COOLING TOWER BASIN

101-BL-001 A-K
PROCESS COOLING TOWER FANS

101-P-001 A/B/C
PROCESS BLOCK COOLING WATER
PUMPS



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A4UV-101-25-PFD-0001 (Rev 0, 8/8/12)



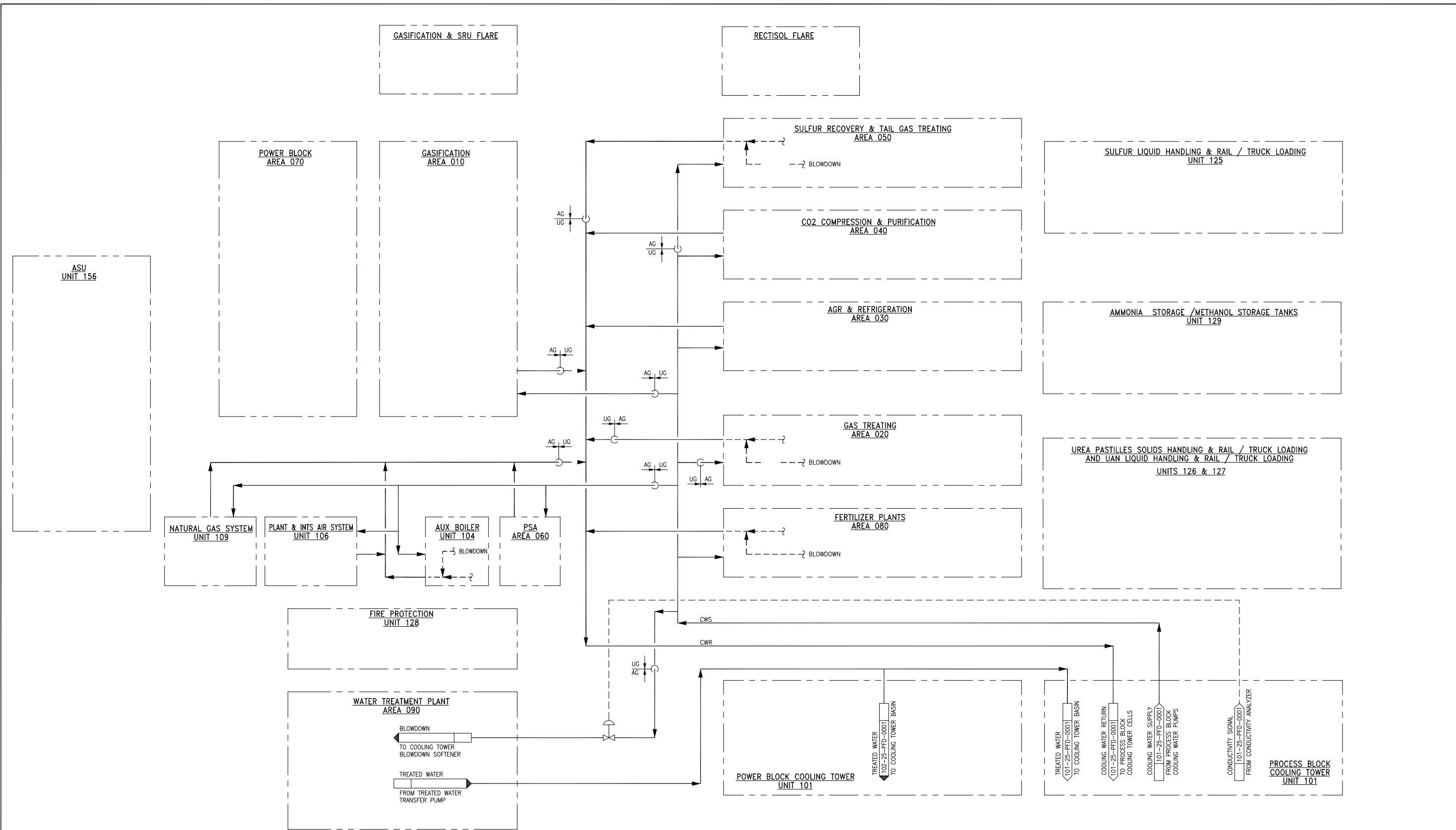
FLUOR®

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HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
COOLING WATER SYSTEM
PROCESS BLOCK

SCALE
NONE

DRAWING NUMBER
101-25-PFD-0001



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Fluor Source Document:
A4UV-101-25-PFD-0002 (Rev 0, 8/8/12)



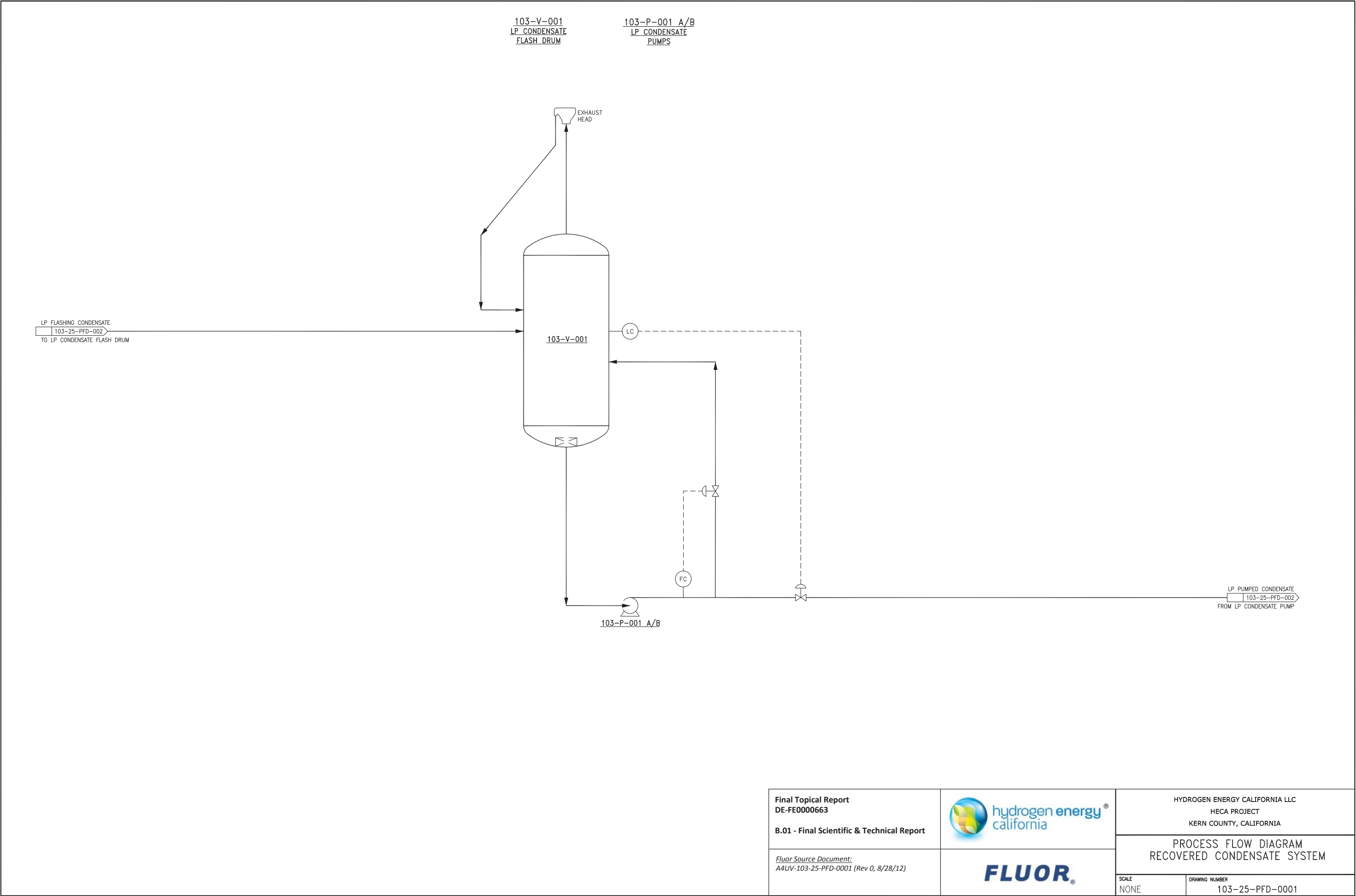
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HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
COOLING WATER DISTRIBUTION SYSTEM
PROCESS BLOCK

SCALE
NONE

DRAWING NUMBER
101-25-PFD-0002



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KERN COUNTY, CALIFORNIA

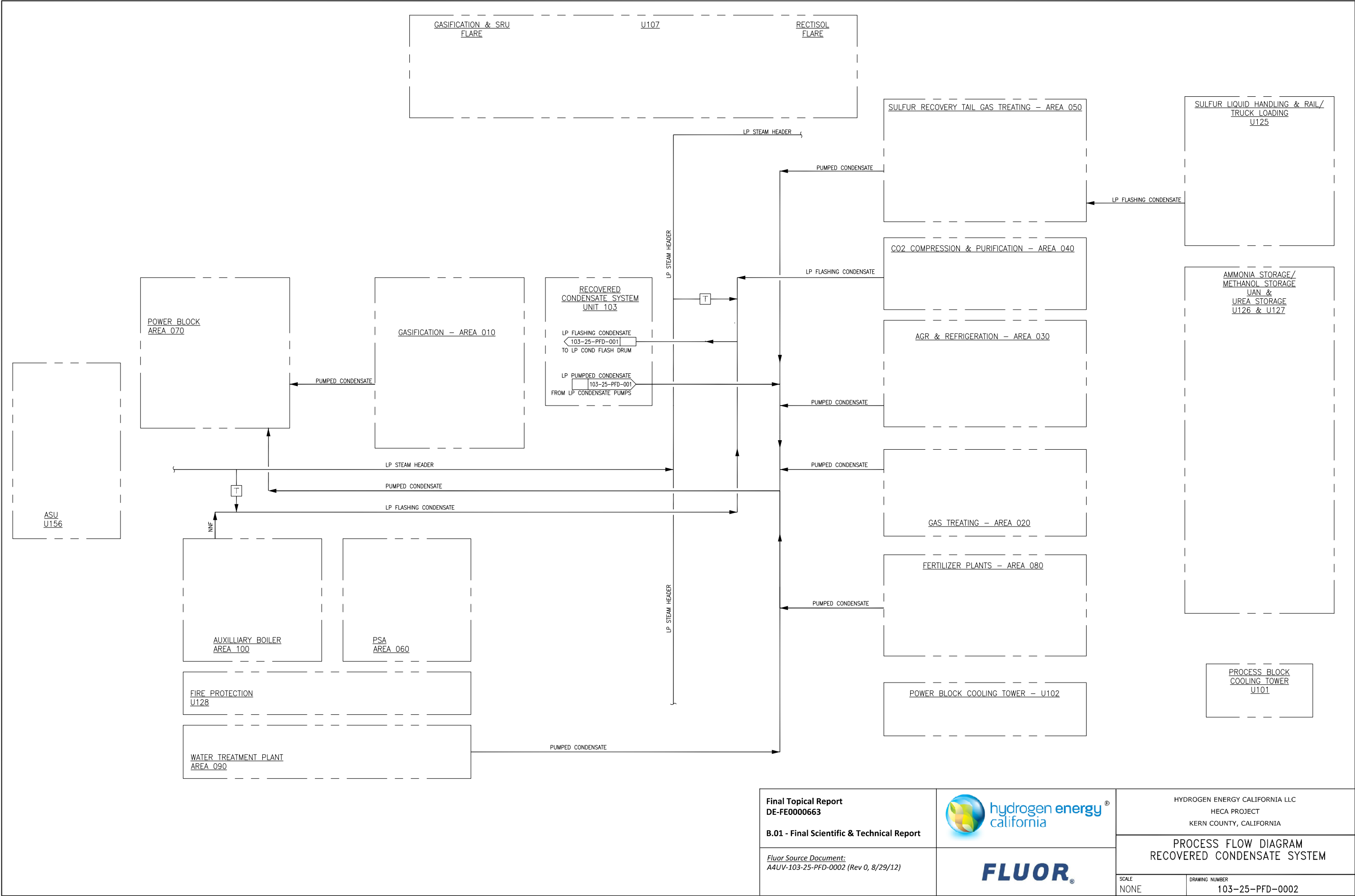
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RECOVERED CONDENSATE SYSTEM

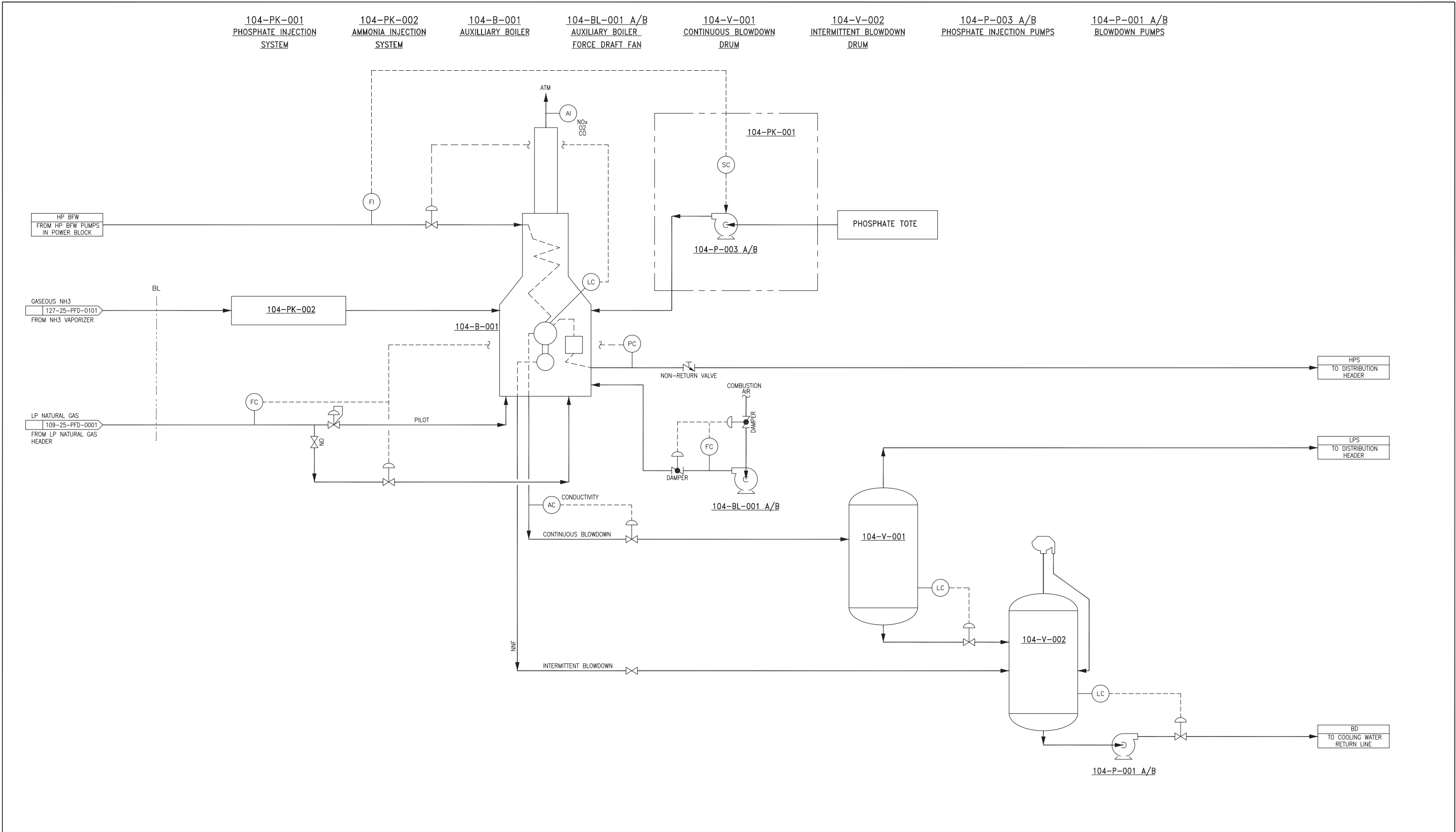
Fluor Source Document:
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SCALE
NONE

DRAWING NUMBER
103-25-PFD-0001

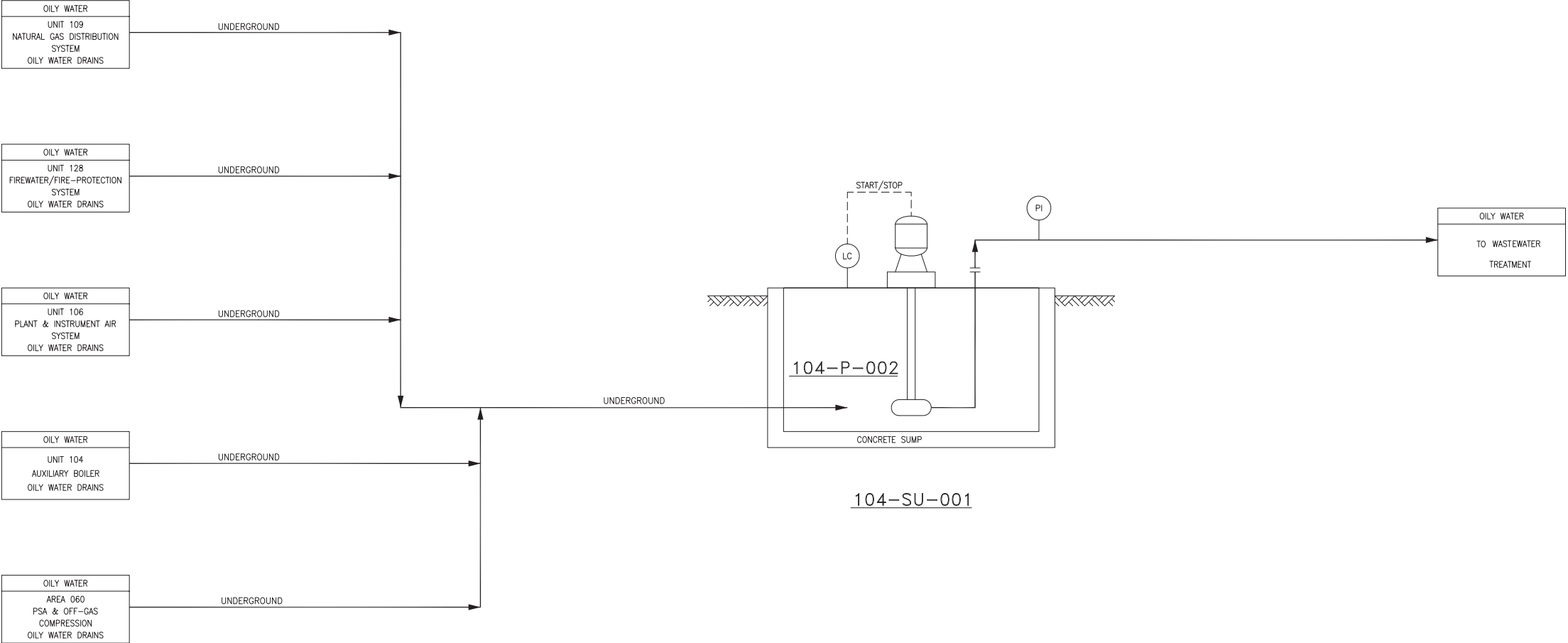




Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report <i>Fluor Source Document:</i> A4UV-104-25-PFD-0001 (Rev 0, 8/20/12)	 	HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA	
		PROCESS FLOW DIAGRAM AUXILIARY BOILER	
		SCALE NONE	DRAWING NUMBER 104-25-PFD-0001

104-SU-001
AUXILIARY BOILER
OILY WATER SUMP

104-P-002
AUXILIARY BOILER
OILY WATER SUMP PUMP



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Fluor Source Document:
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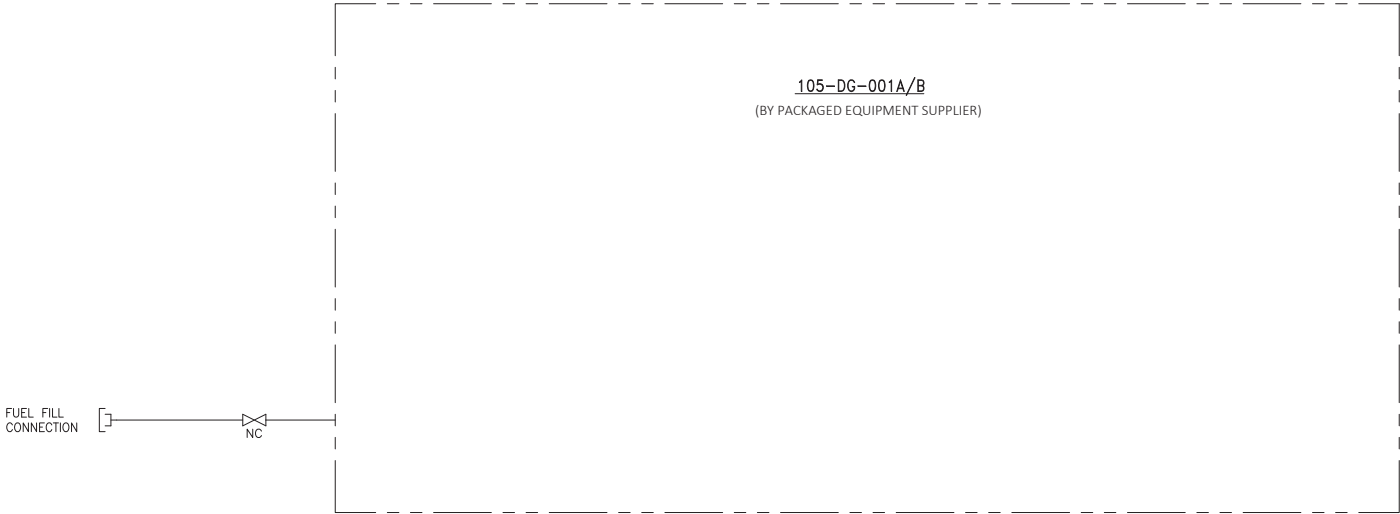
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
AUXILIARY BOILER
OILY WATER SUMP

SCALE
NONE

DRAWING NUMBER
104-25-PFD-0002

105-DG-001A/B
EMERGENCY DIESEL GENERATOR



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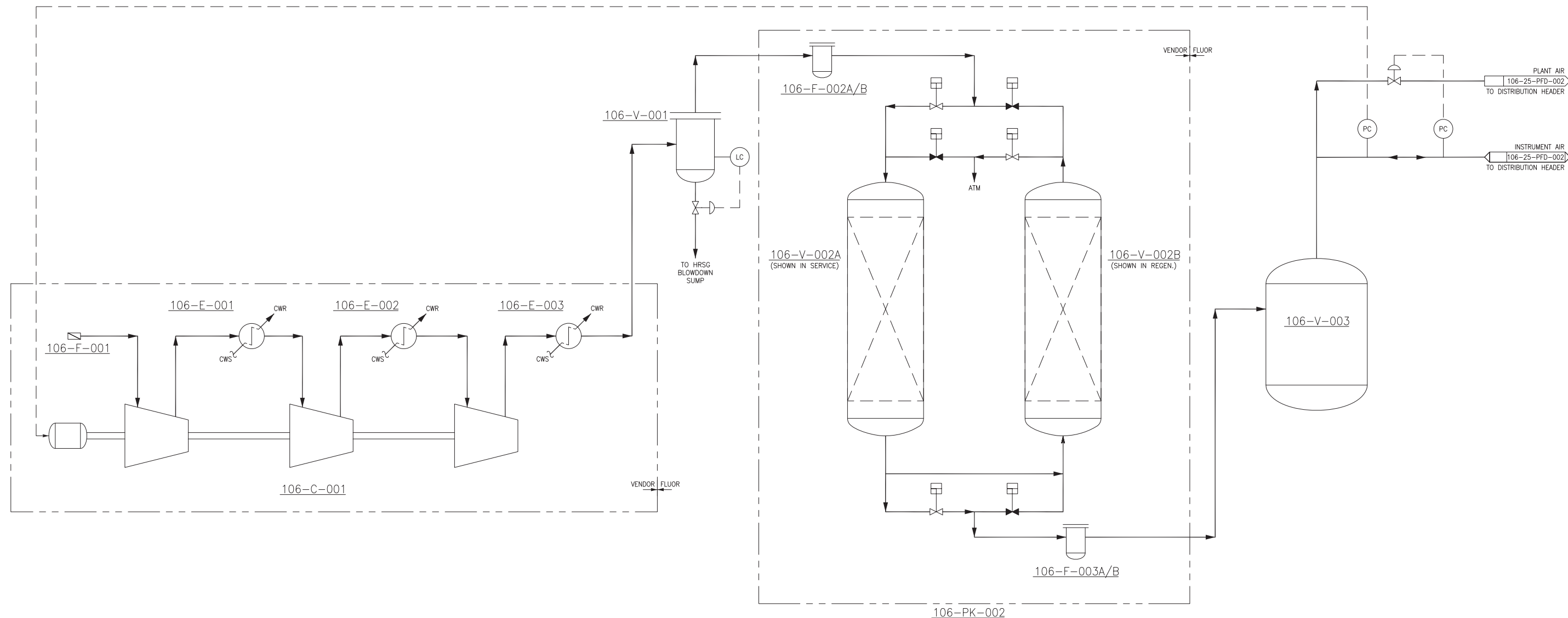
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
EMERGENCY DIESEL GENERATOR

SCALE
NONE

DRAWING NUMBER
105-25-PFD-0001

106-F-001 INLET AIR FILTER/SILENCER	106-C-001 AIR COMPRESSOR PACKAGE	106-E-001 AIR COMPRESSOR 1ST STAGE INTERCOOLER	106-E-002 AIR COMPRESSOR 2ND STAGE INTERCOOLER	106-E-003 AIR COMPRESSOR DISCHARGE COOLER	106-V-001 AIR DRYER KO DRUM	106-PK-002 AIR DRYER PACKAGE	106-F-002 A/B AIR DRYER PRE-FILTERS	106-V-002 A/B AIR DRYERS	106-F-003 A/B AIR DRYER POST-FILTERS	106-V-003 INSTRUMENT AIR RECEIVER



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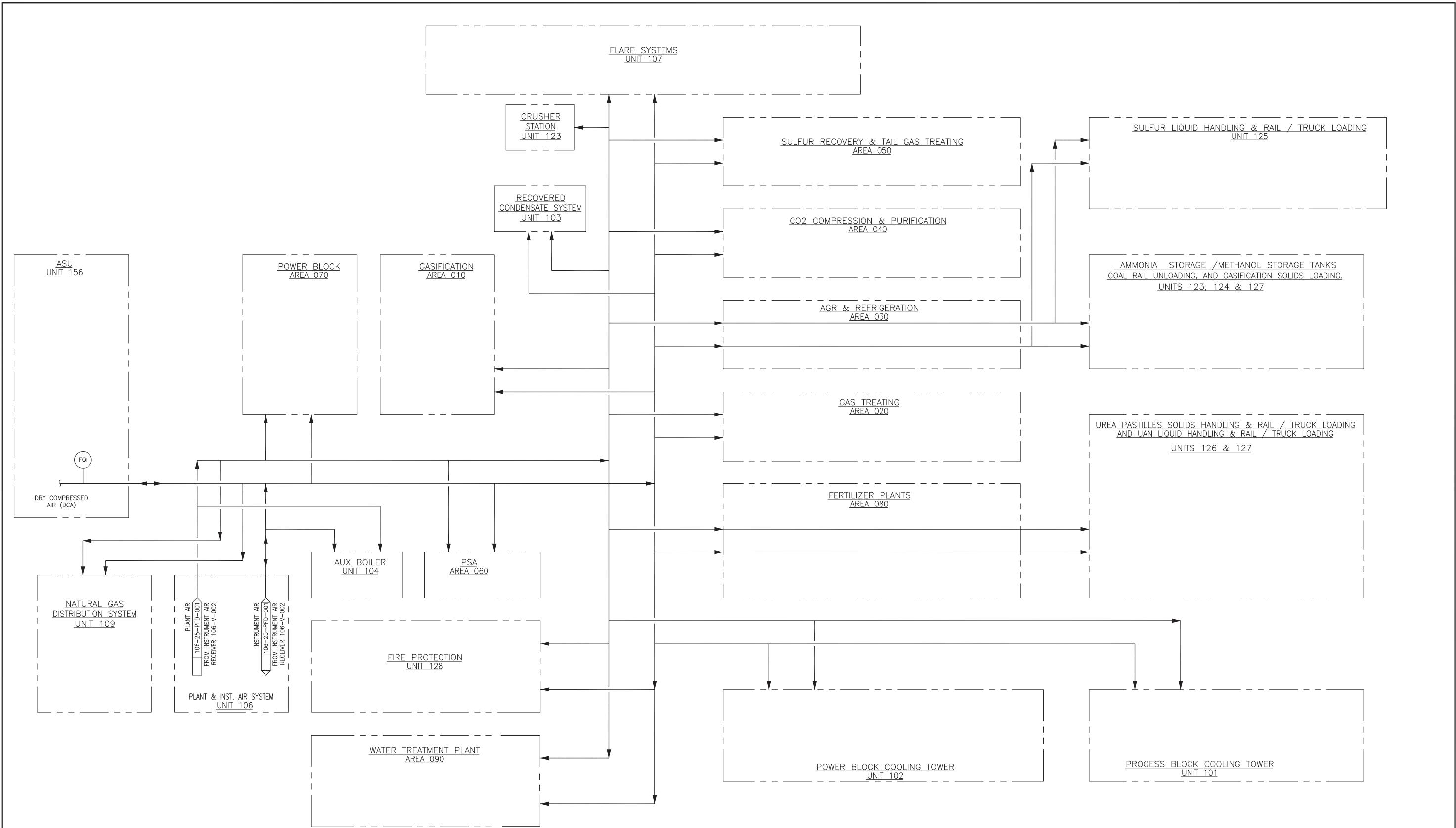
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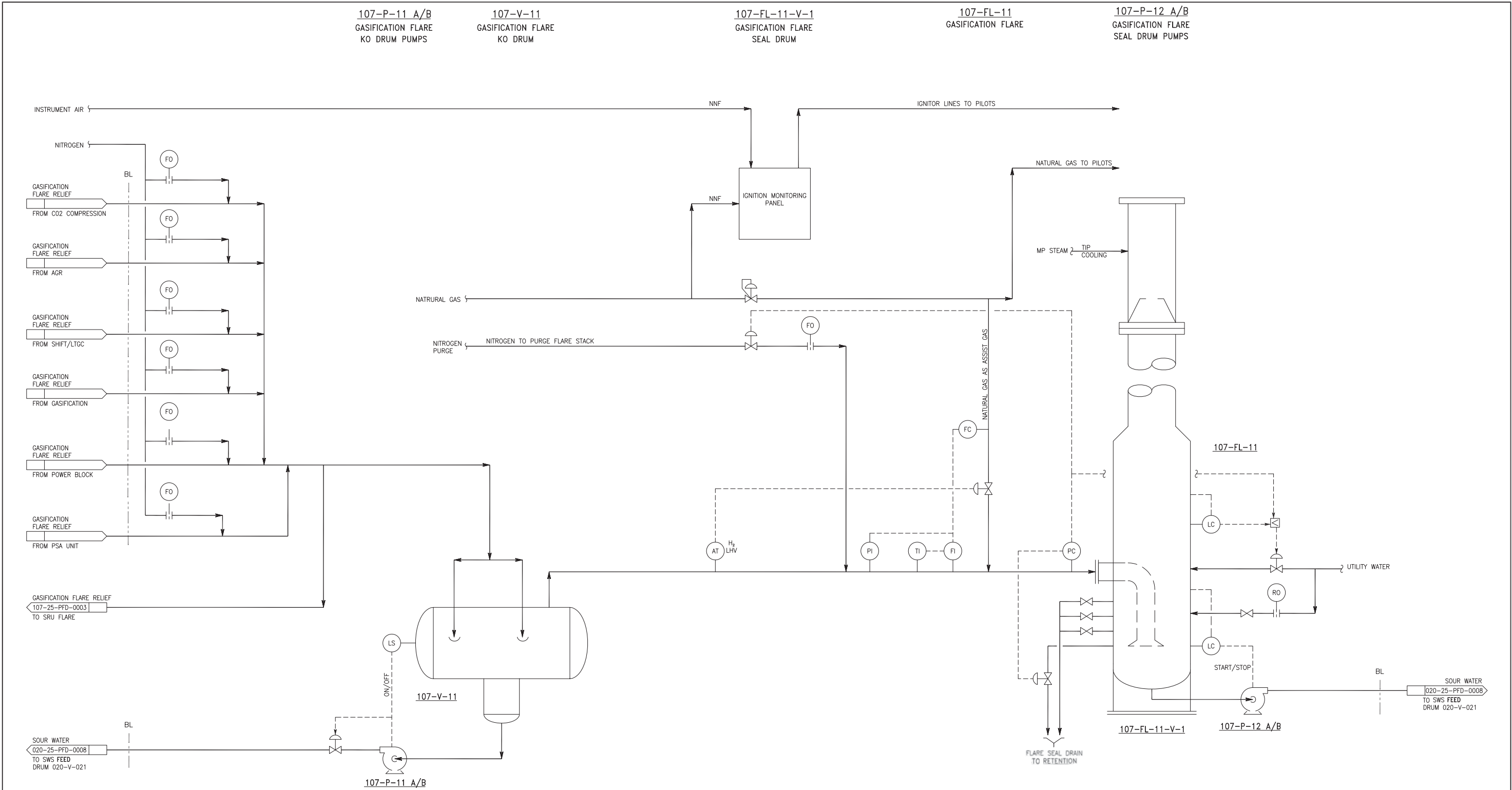
PROCESS FLOW DIAGRAM
PLANT & INSTRUMENT AIR SYSTEMS

SCALE
NONE

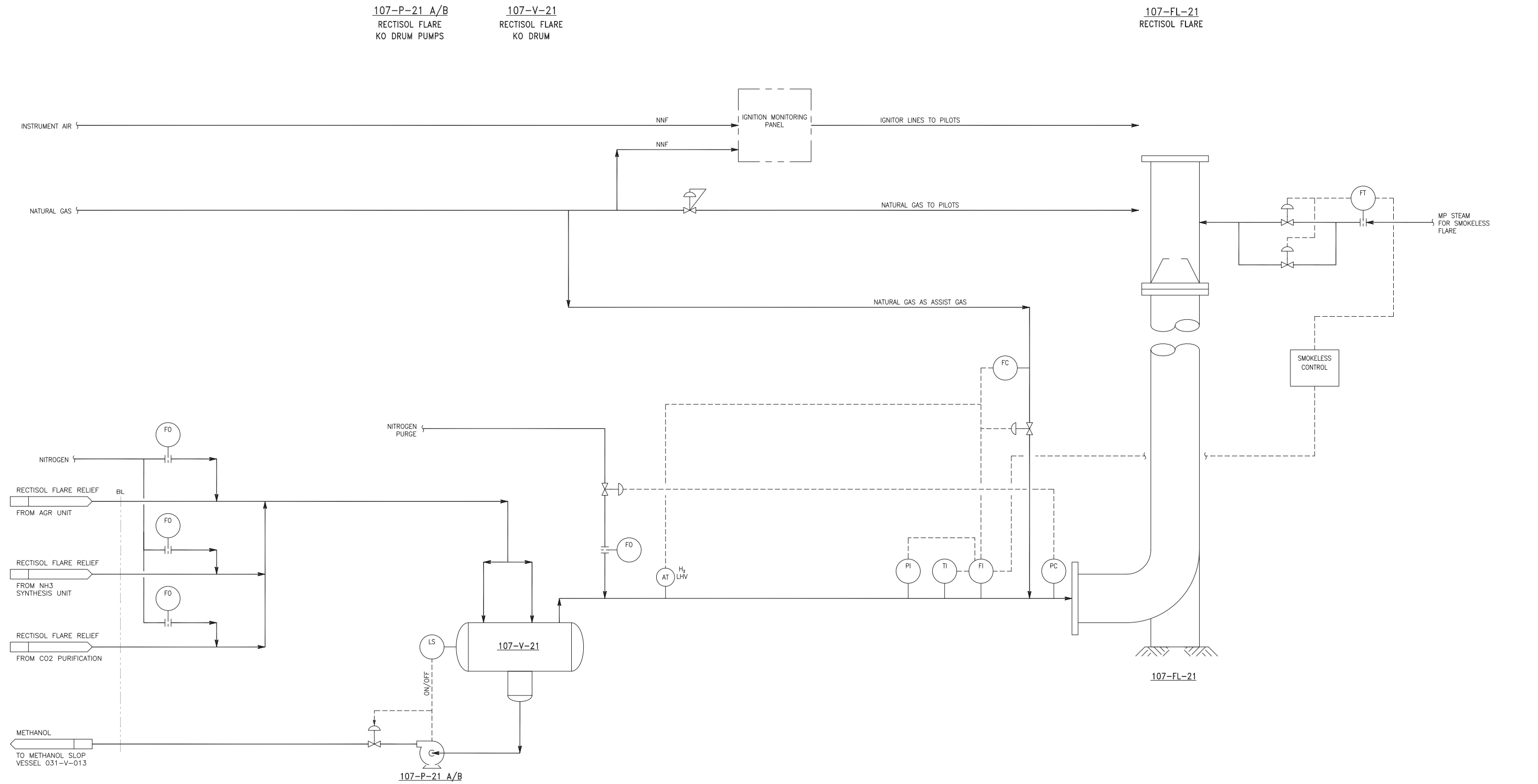
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106-25-PFD-0001



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		PROCESS FLOW DIAGRAM PLANT & INSTRUMENT AIR DISTRIBUTION SYSTEM	
		SCALE NONE	DRAWING NUMBER 106-25-PFD-0002



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		PROCESS FLOW DIAGRAM GASIFICATION FLARE	
		SCALE NONE	DRAWING NUMBER 107-25-PFD-0001



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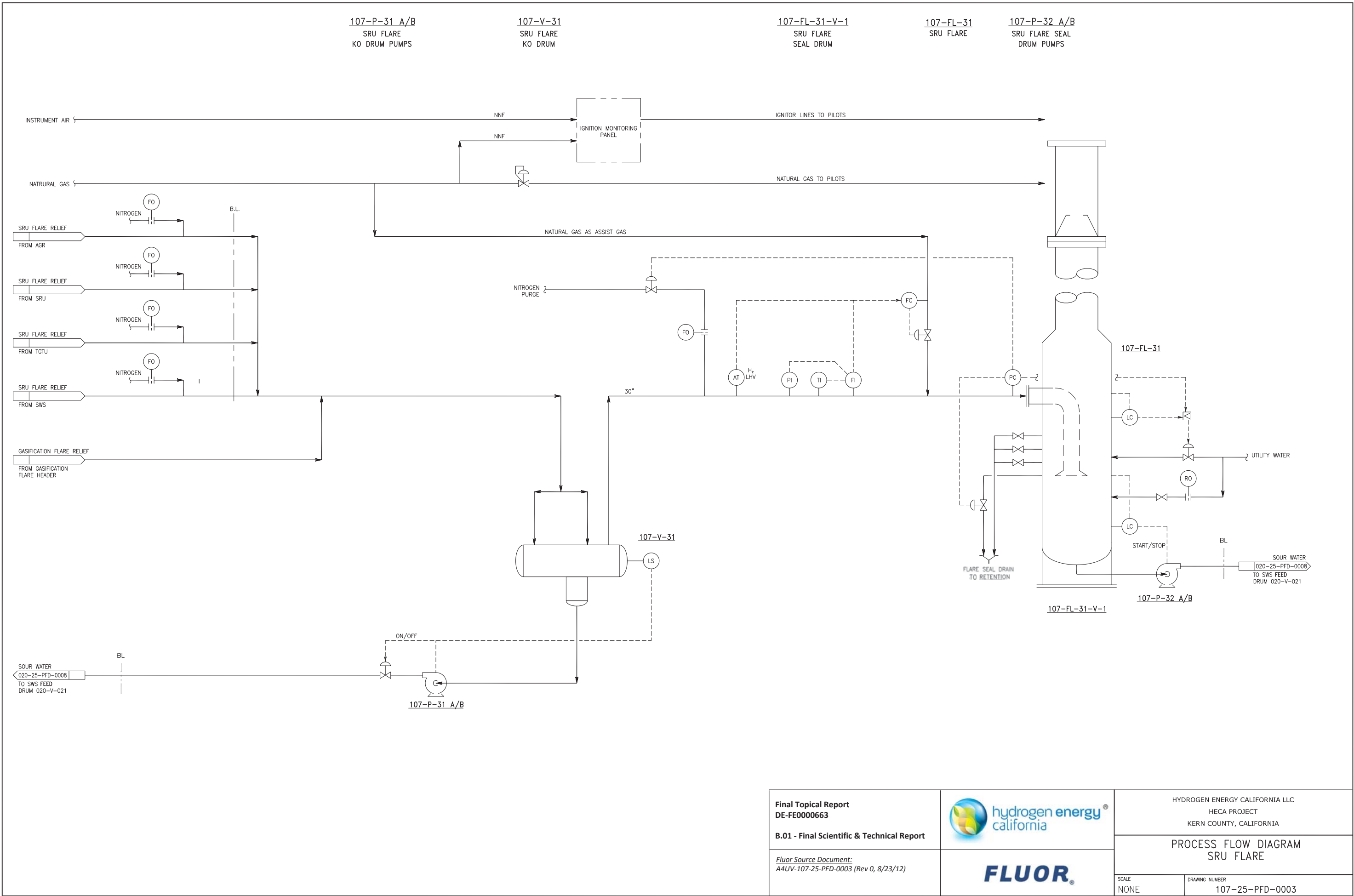
PROCESS FLOW DIAGRAM
RECTISOL FLARE

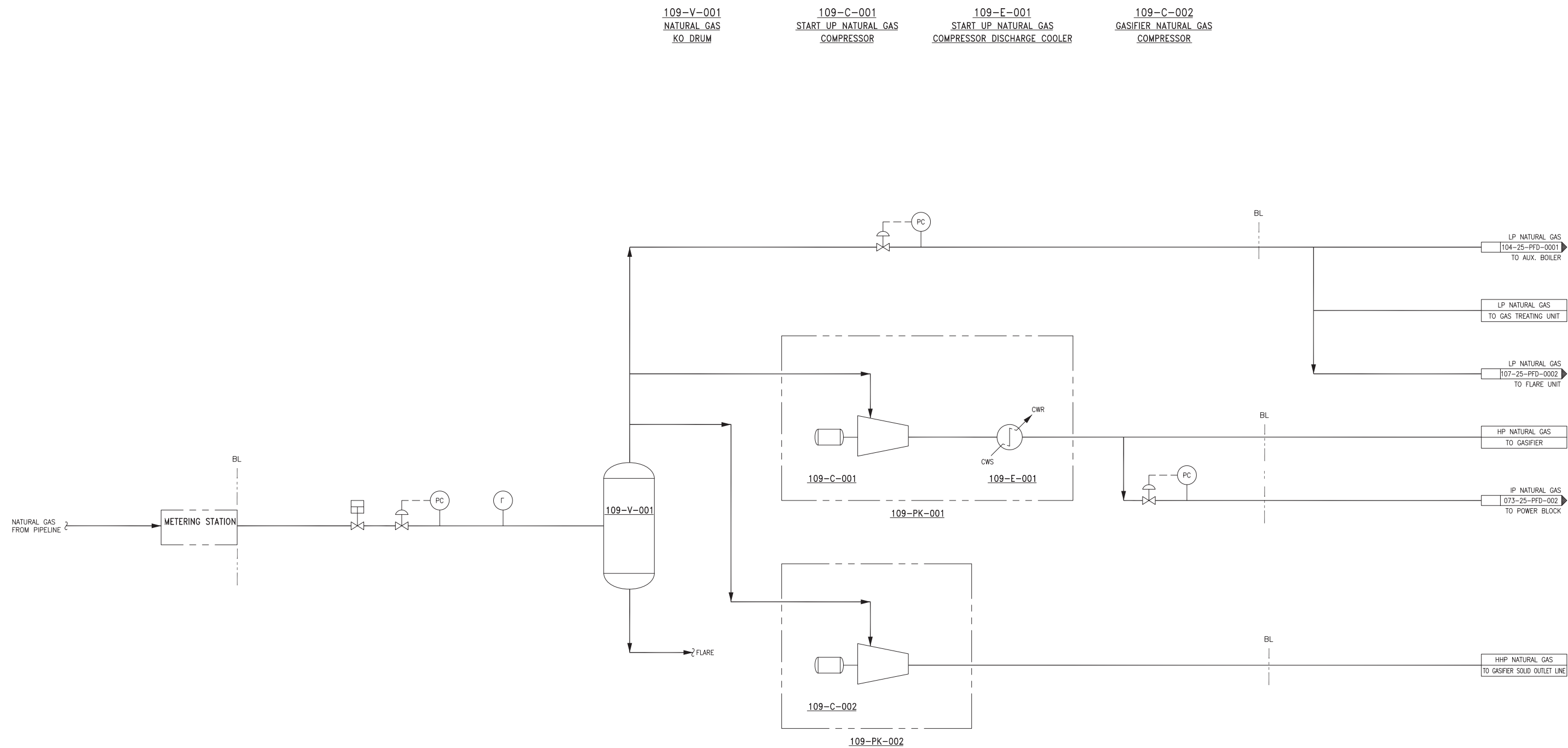
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A4UV-107-25-PFD-0002 (Rev 0, 8/23/12)



SCALE
NONE

DRAWING NUMBER
107-25-PFD-0002





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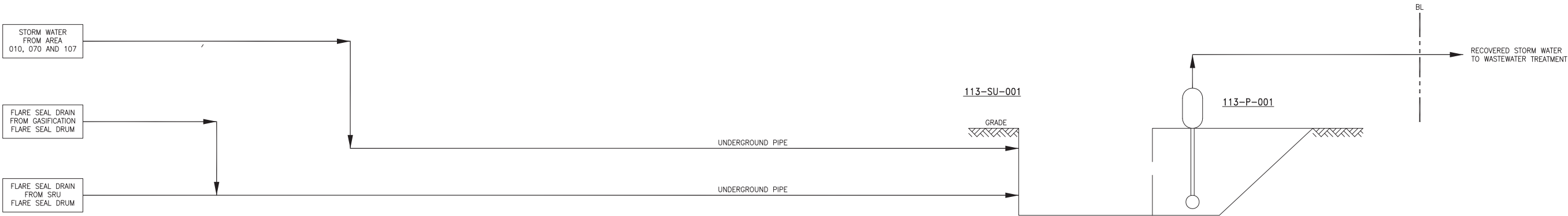
PROCESS FLOW DIAGRAM
NATURAL GAS DISTRIBUTION SYSTEM

SCALE
NONE

DRAWING NUMBER
109-25-PFD-0001

113-SU-001
L2 LINED STORM WATER RETENTION
BASIN

113-P-001
STORM WATER RETENTION BASIN
PUMP



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Fluor Source Document:
A4UV-113-25-PFD-0001 (Rev 0, 8/31/12)

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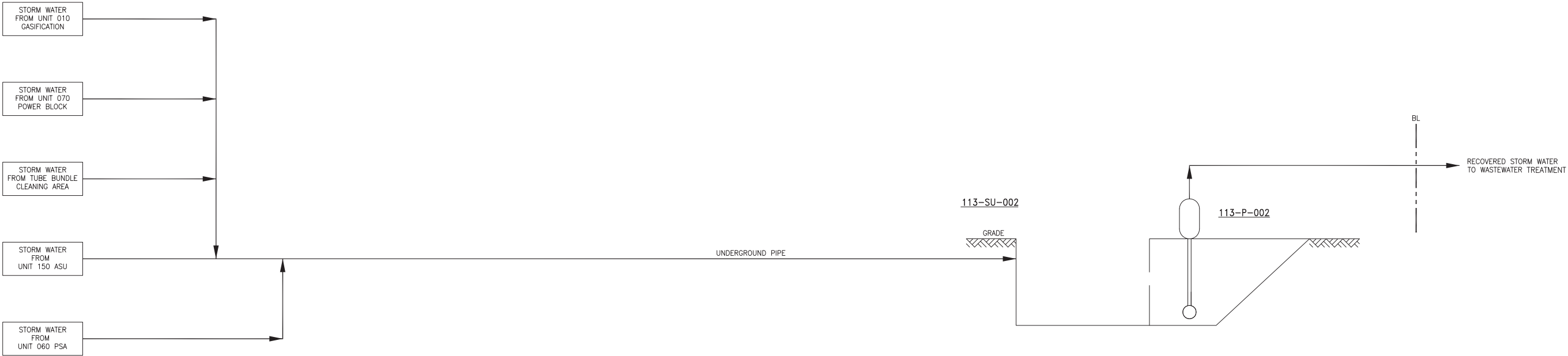
PROCESS FLOW DIAGRAM
STORM WATER SYSTEM
L2 STORM WATER RETENTION BASIN

SCALE
NONE

DRAWING NUMBER
113-25-PFD-0001

113-SU-002
L4 LINED STORM WATER RETENTION
BASIN

113-P-002
STORM WATER RETENTION BASIN
PUMP



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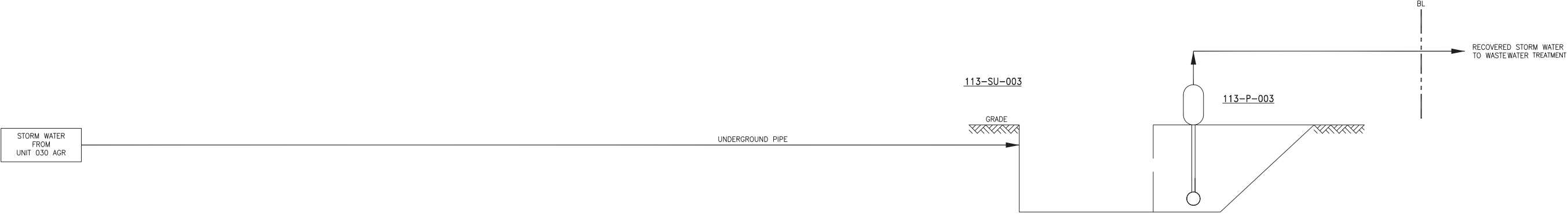
PROCESS FLOW DIAGRAM
STORM WATER SYSTEM
L4 STORM WATER RETENTION BASIN

SCALE
NONE

DRAWING NUMBER
113-25-PFD-0002

113-SU-003
L5 LINED STORM WATER RETENTION
BASIN

113-P-003
STORM WATER RETENTION BASIN
PUMP



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A4UV-113-25-PFD-0003 (Rev 0, 8/31/12)

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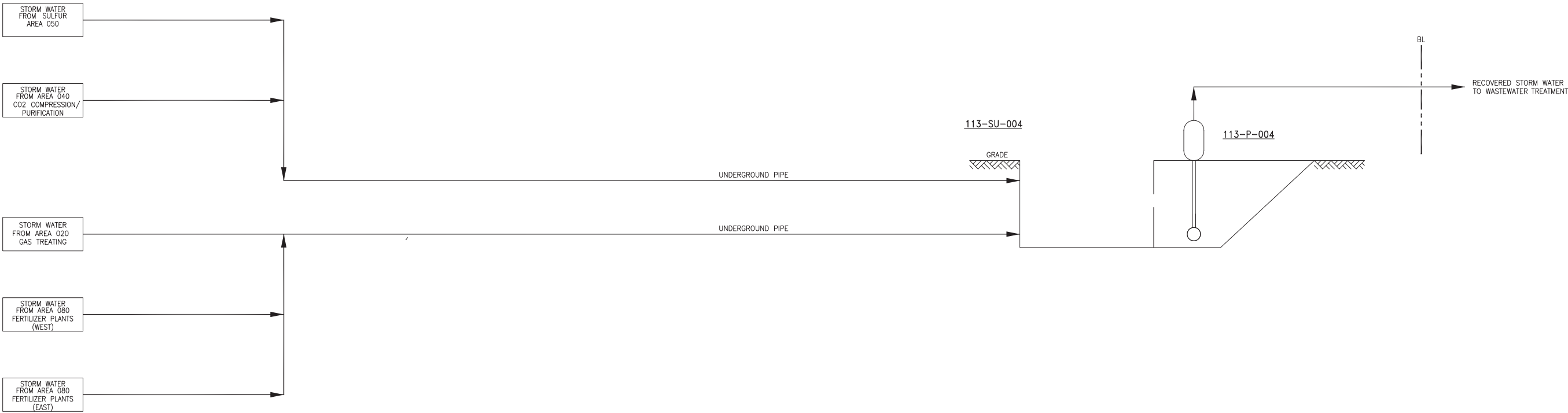
PROCESS FLOW DIAGRAM
STORM WATER SYSTEM
L5 STORM WATER RETENTION BASIN

SCALE
NONE

DRAWING NUMBER
113-25-PFD-0003

113-SU-004
L6 LINED STORM WATER RETENTION
BASIN

113-P-004
STORM WATER RETENTION BASIN
PUMP



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A4UV-113-25-PFD-0004 (Rev 0, 8/31/12)

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PROCESS FLOW DIAGRAM
STORM WATER SYSTEM
L6 STORM WATER RETENTION BASIN

SCALE
NONE

DRAWING NUMBER
113-25-PFD-0004

113-SU-005
L12 LINED STORM WATER RETENTION
BASIN

113-P-005
STORM WATER RETENTION BASIN
PUMP



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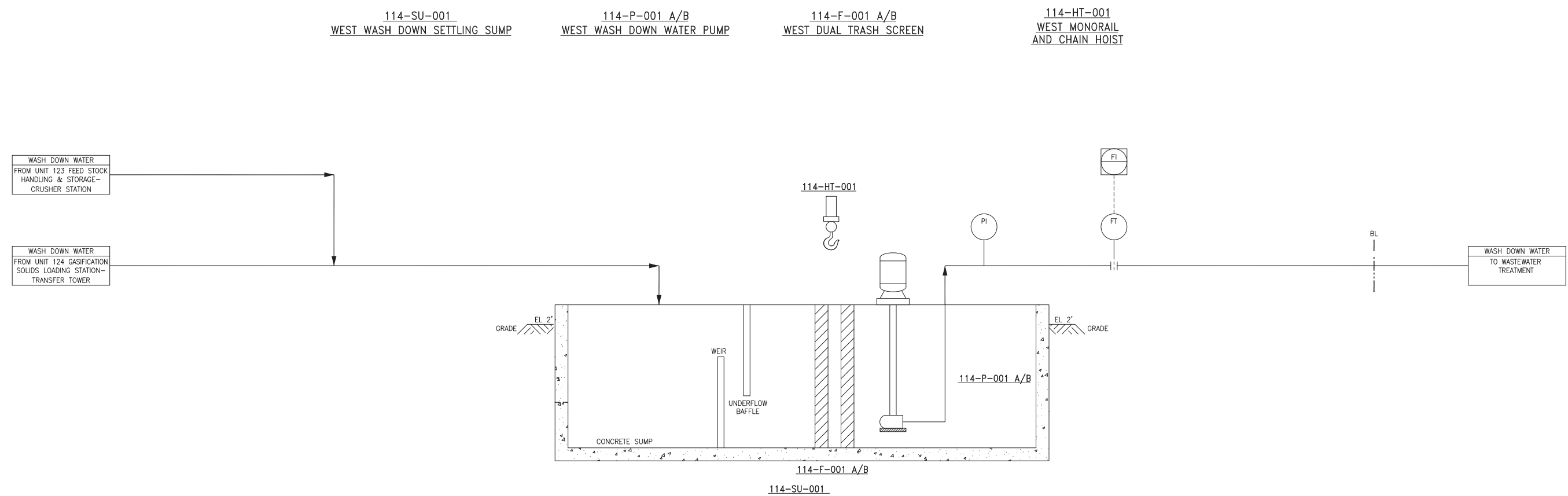
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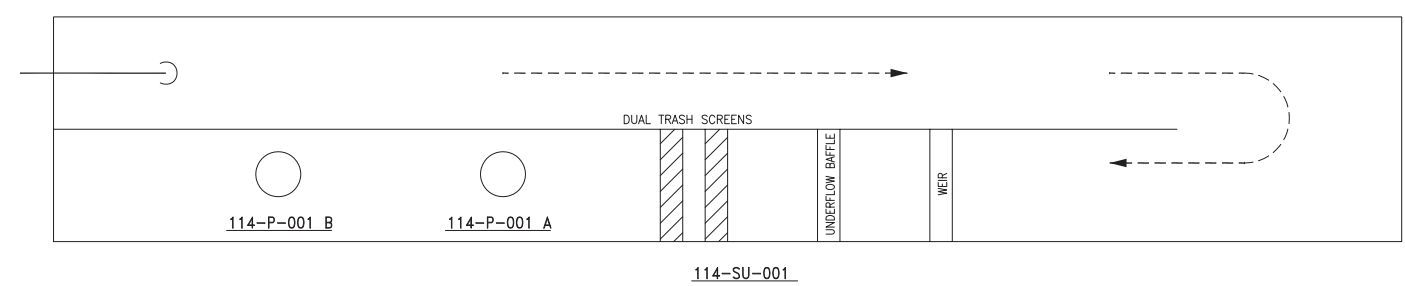
PROCESS FLOW DIAGRAM
STORM WATER SYSTEM
L12 STORM WATER RETENTION BASIN

SCALE
NONE

DRAWING NUMBER
113-25-PFD-0005



PLAN VIEW



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		PROCESS FLOW DIAGRAM SOLIDS HANDLING DRAINAGE SYSTEM WEST WASH DOWN SUMP SYSTEM	
<i>Fluor Source Document:</i> A4UV-114-25-PFD-0001 (Rev 0, 8/17/12)		SCALE NONE	DRAWING NUMBER 114-25-PFD-0001

114-SU-002
EAST WASH DOWN SETTLING SUMP

114-P-002 A/B
EAST WASH DOWN WATER PUMP

114-F-002 A/B
EAST DUAL TRASH SCREEN

114-HT-002
EAST MONORAIL
AND CHAIN HOIST

WASH DOWN WATER
FROM UNIT 123 FEED STOCK
HANDLING & STORAGE
TRANSFER TOWER

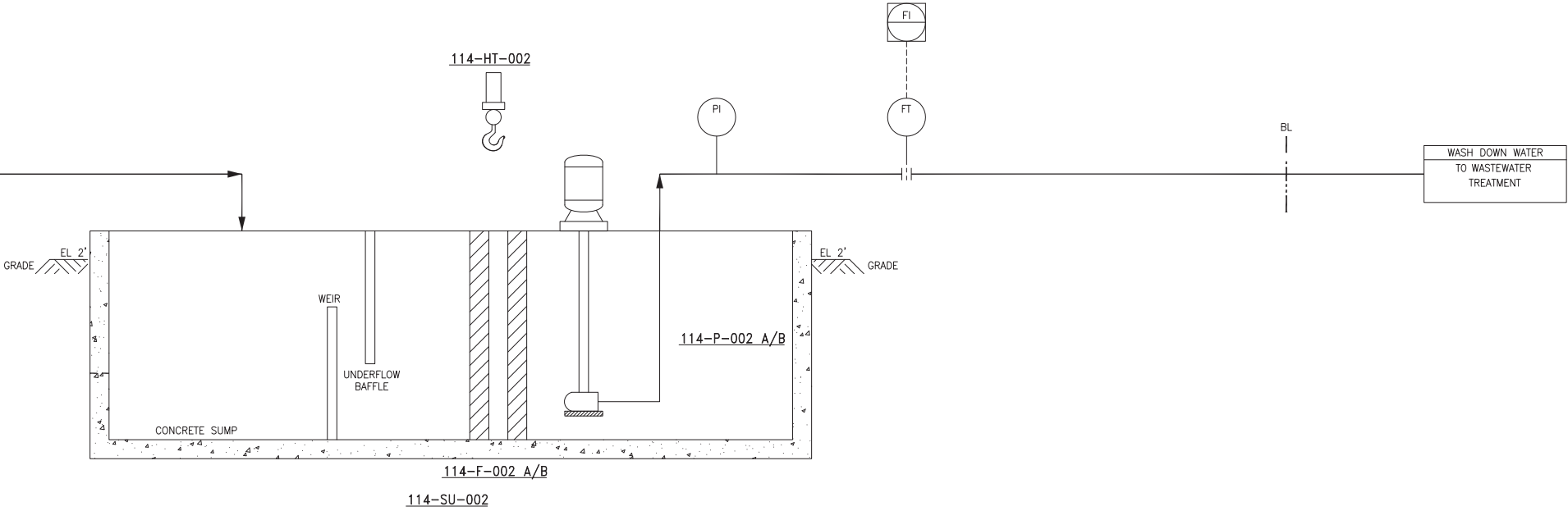
WASH DOWN WATER
FROM UNIT 123 FEED STOCK
HANDLING & STORAGE
PETCOKE AREA

WASH DOWN WATER
FROM UNIT 123 FEED STOCK
HANDLING & STORAGE
COAL AREA

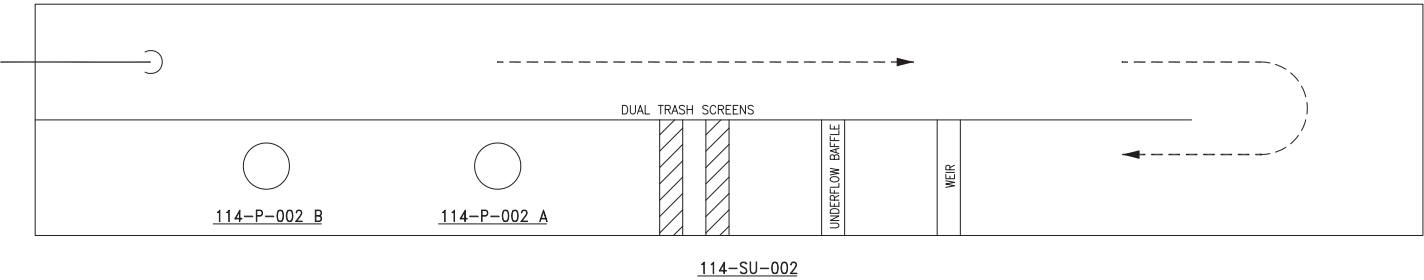
WASH DOWN WATER
FROM UNIT 123 FEED STOCK
HANDLING & STORAGE
PETCOKE UNLOADING

WASH DOWN WATER
FROM UNIT 124 GASIFICATION
SOLIDS LOADING STATION

WASH DOWN WATER
FROM UNIT 123 FEED STOCK
HANDLING & STORAGE
COAL UNLOADING



PLAN VIEW



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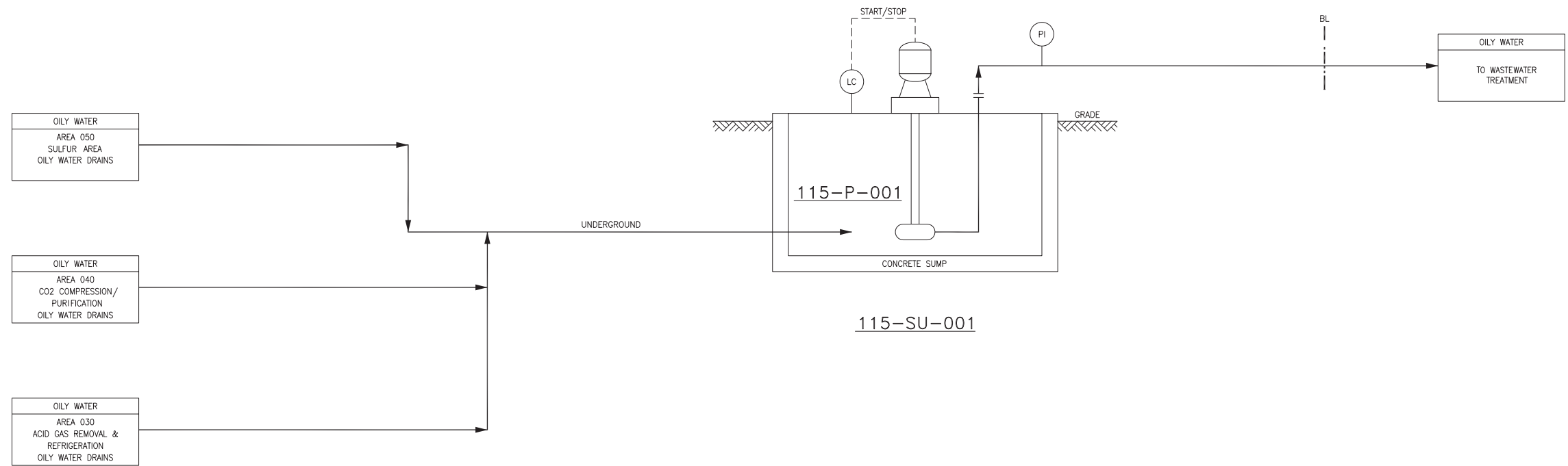
PROCESS FLOW DIAGRAM
SOLIDS HANDLING DRAINAGE SYSTEM
EAST WASH DOWN SUMP SYSTEM

SCALE
NONE

DRAWING NUMBER
114-25-PFD-0002

115-SU-001
NORTH
OILY WATER SUMP

115-P-001
NORTH OILY
WATER SUMP PUMP



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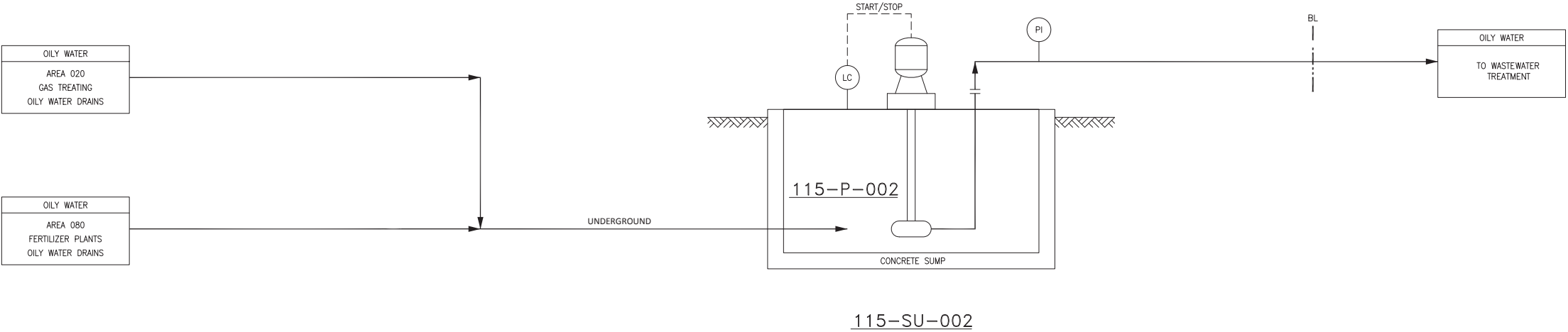
PROCESS FLOW DIAGRAM
OILY WATER SEWER
NORTH OILY WATER SUMP

SCALE
NONE

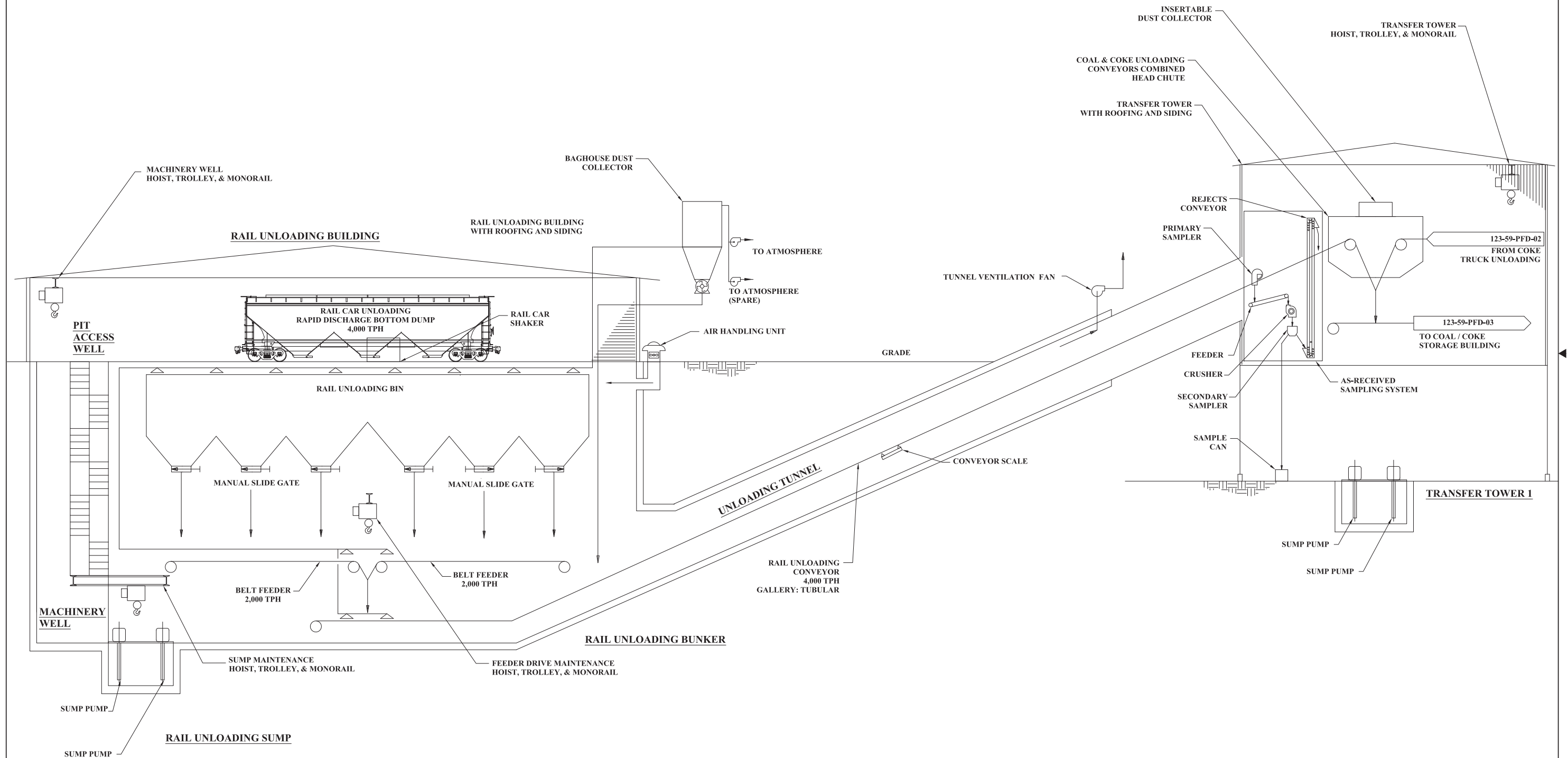
DRAWING NUMBER
115-25-PFD-0001

115-SU-002
SOUTH
OILY WATER SUMP

115-P-002
SOUTH OILY
WATER SUMP PUMP



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		PROCESS FLOW DIAGRAM OILY WATER SEWER SOUTH OILY WATER SUMP	
		SCALE NONE	DRAWING NUMBER 115-25-PFD-0002



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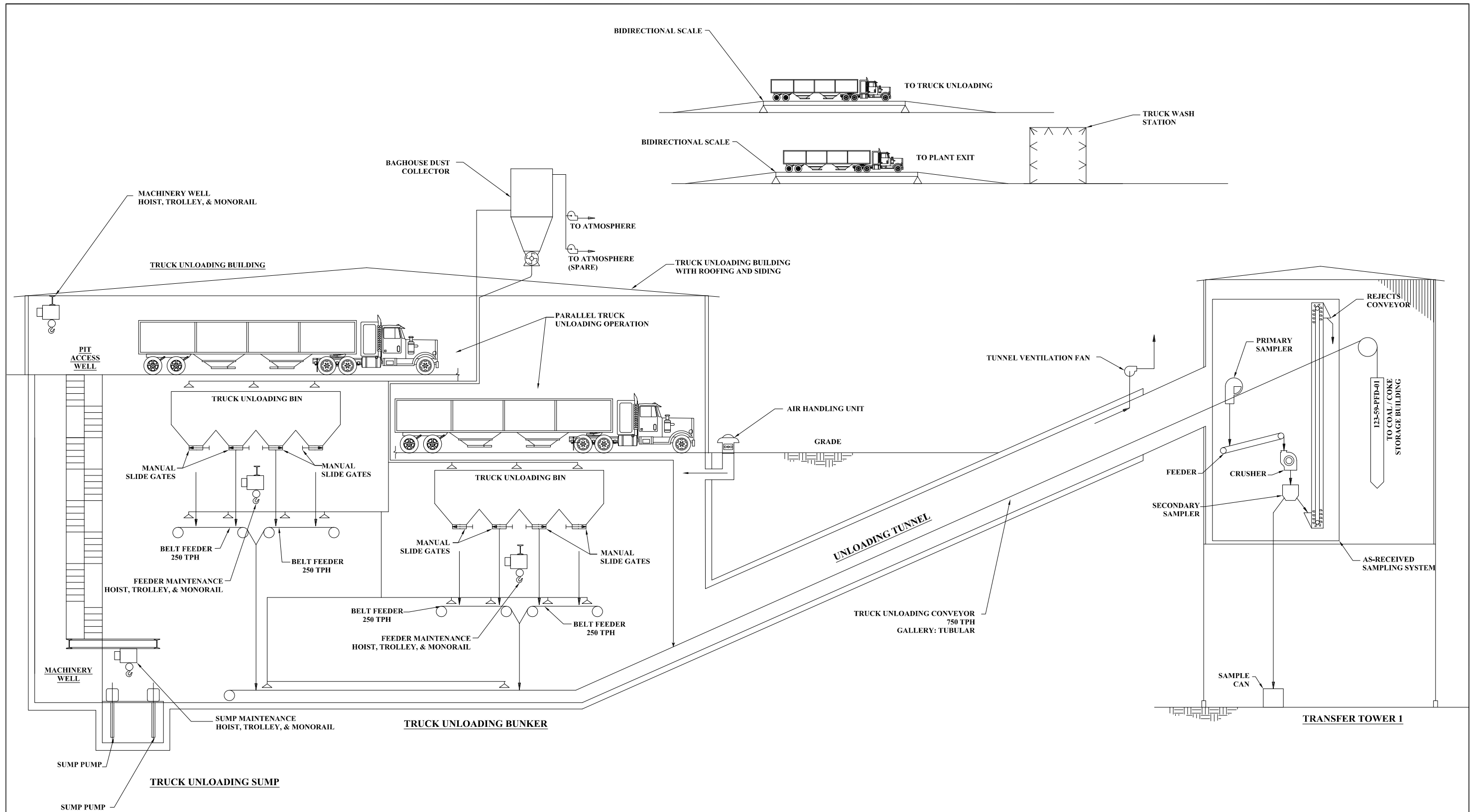
Fluor Source Document:
A4UV-123-59-PFD-01 (Rev E, 12/17/12)



HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA
PROCESS FLOW DIAGRAM
COAL RAIL UNLOADING SYSTEM

SCALE
NONE

DRAWING NUMBER
123-59-PFD-01



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Fluor Source Document:
A4UV-123-59-PFD-02 (Rev E, 12/17/12)



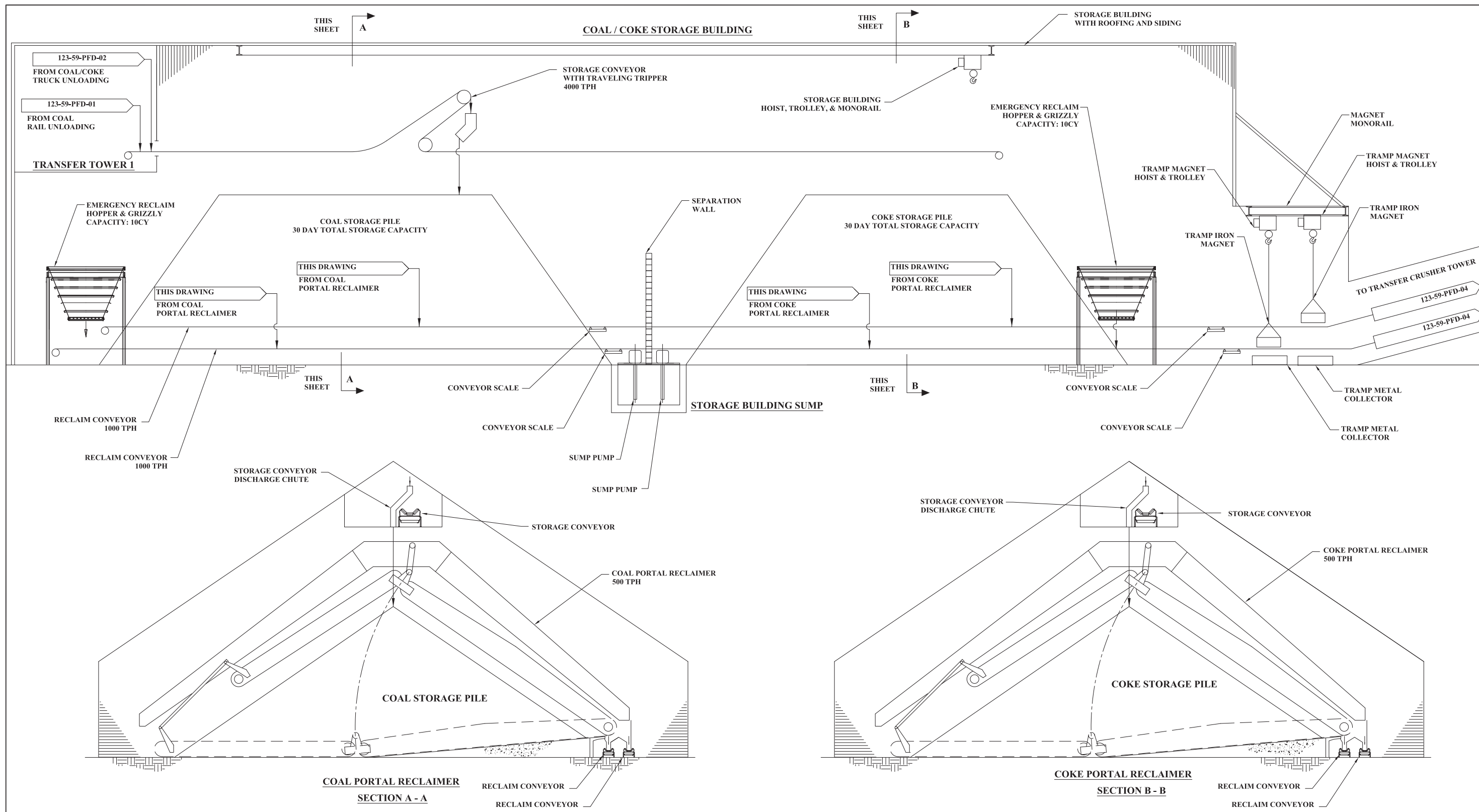
FLUOR

HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
COAL/COKE TRUCK UNLOADING SYSTEM

SCALE
NONE

DRAWING NUMBER
123-59-PFD-02



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Fluor Source Document:
A4UV-123-59-PFD-03 (Rev E, 12/17/12)



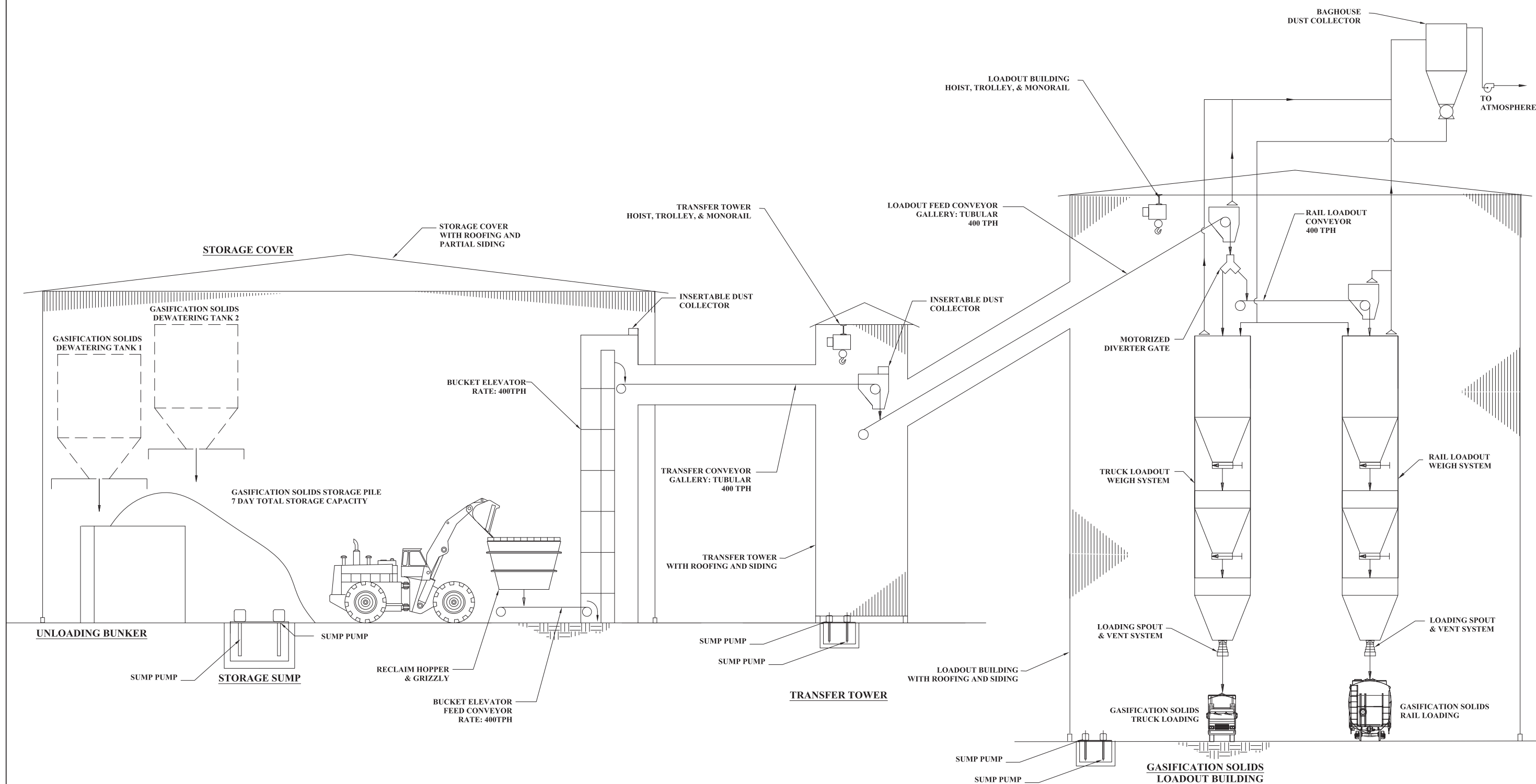
FLUOR

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HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
COAL/COKE STORAGE & RECLAIM SYSTEM

SCALE
NONE

DRAWING NUMBER
123-59-PFD-03



Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report <i>Fluor Source Document:</i> A4UV-124-59-PFD-01 (Rev E, 12/17/12)	 	HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA	
		PROCESS FLOW DIAGRAM GASIFICATION SOLIDS MATERIAL HANDLING SYSTEM	
		SCALE NONE	DRAWING NUMBER 124-59-PFD-01

125-TK-001
DEGASSED SULFUR
STORAGE TANK

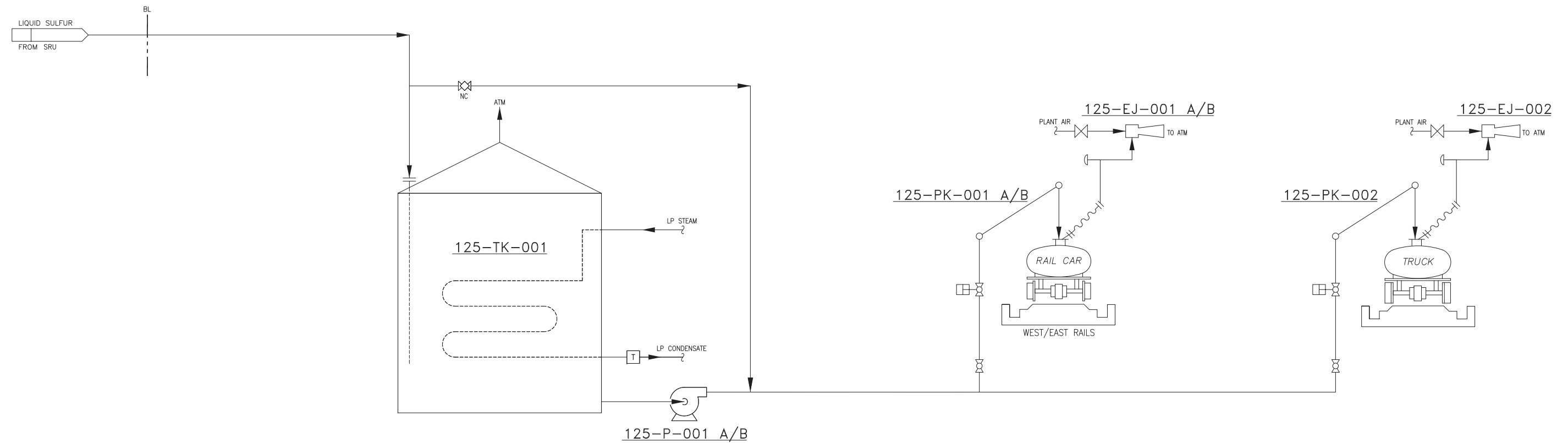
125-PK-001 A/B
SULFUR RAILCAR
LOADING ARMS

125-PK-002
SULFUR TRUCK
LOADING ARM

125-P-001 A/B
SULFUR LOADING PUMPS

125-EJ-001 A/B
RAILCAR LOADING
ARM EJECTORS

125-EJ-002
TRUCK LOADING
ARM EJECTOR



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Fluor Source Document:
A4UV-125-25-PFD-0001 (Rev 0, 8/22/12)

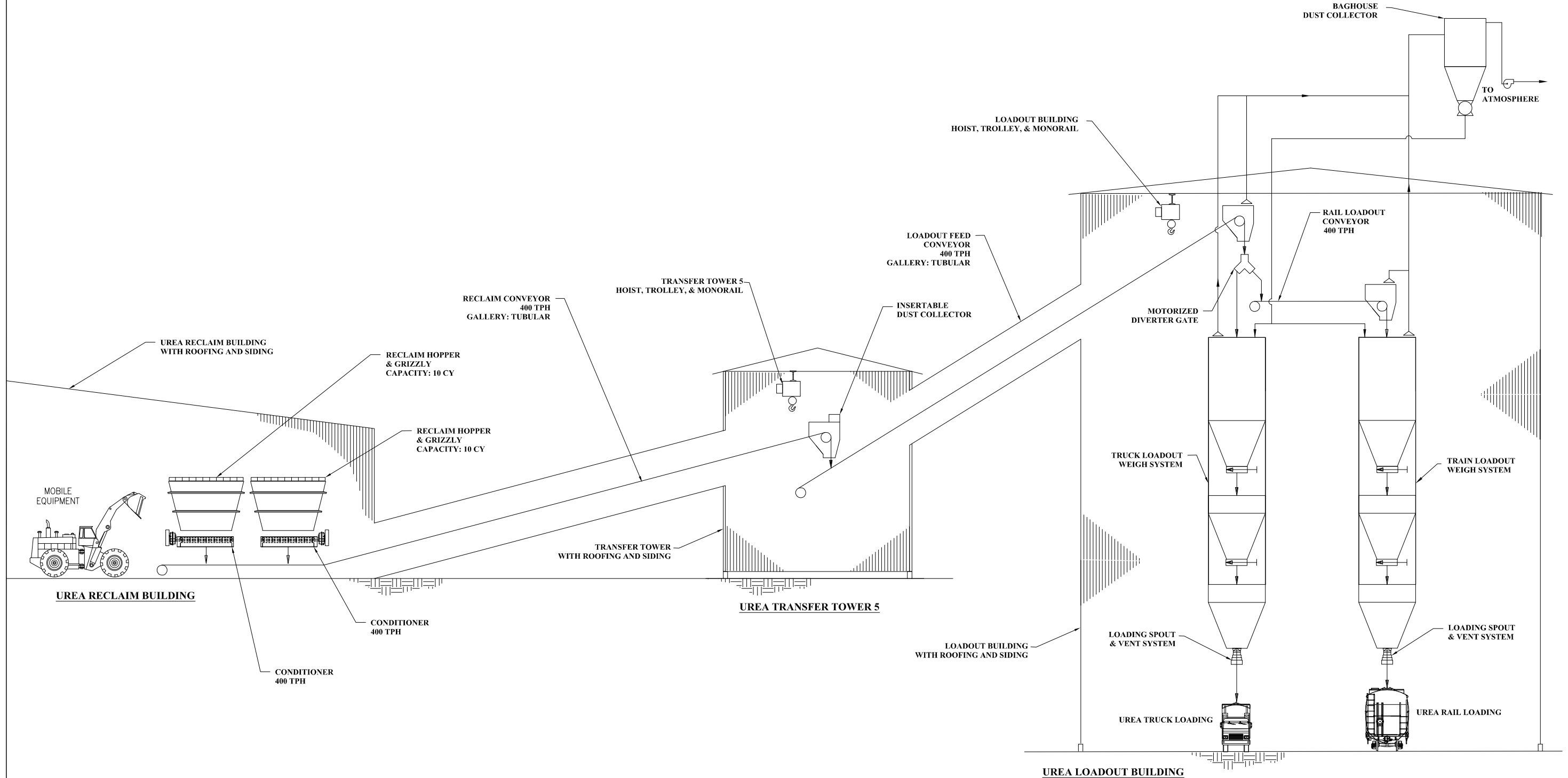
FLUOR

HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
SULFUR LIQUID STORAGE,
HANDLING & RAIL / TRUCK LOADING

SCALE
NONE

DRAWING NUMBER
125-25-PFD-0001



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Fluor Source Document:
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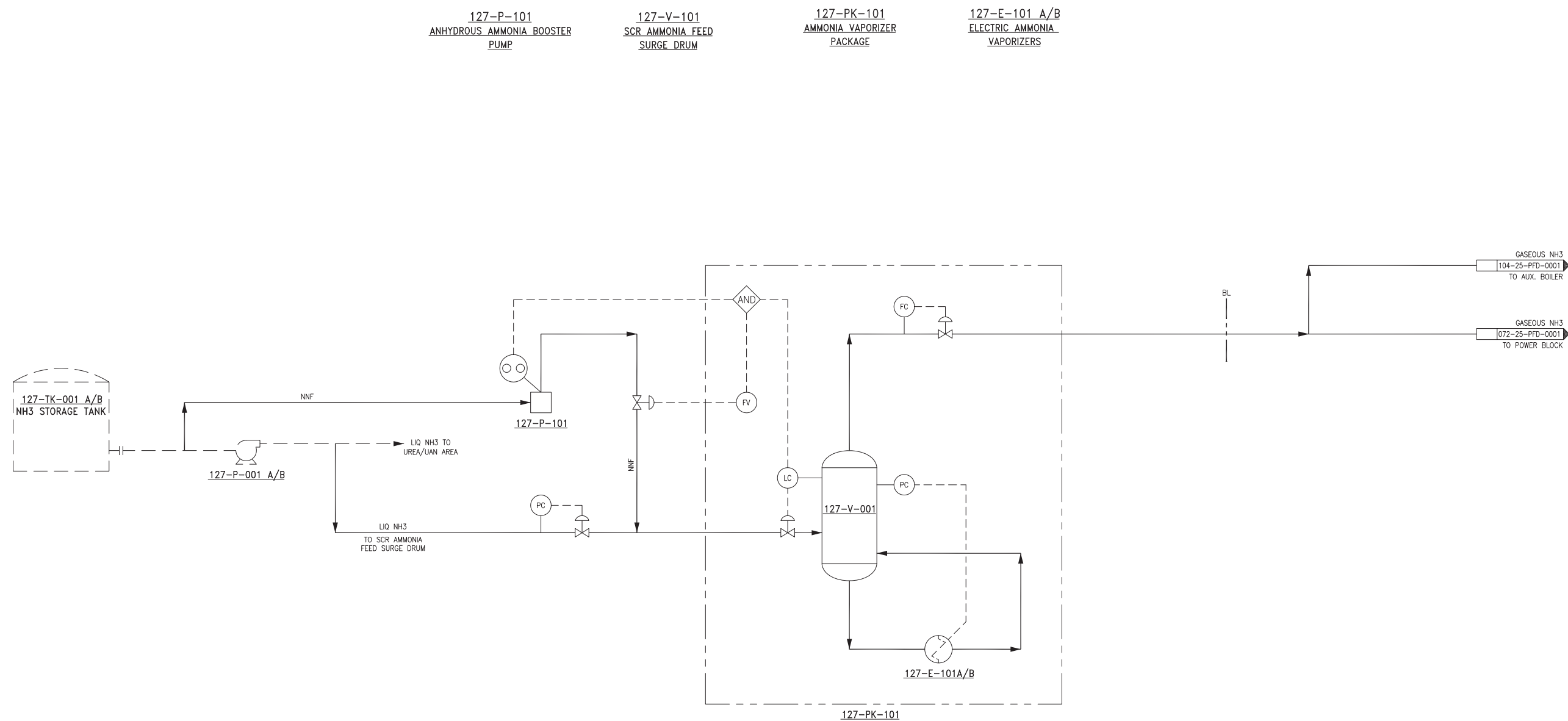


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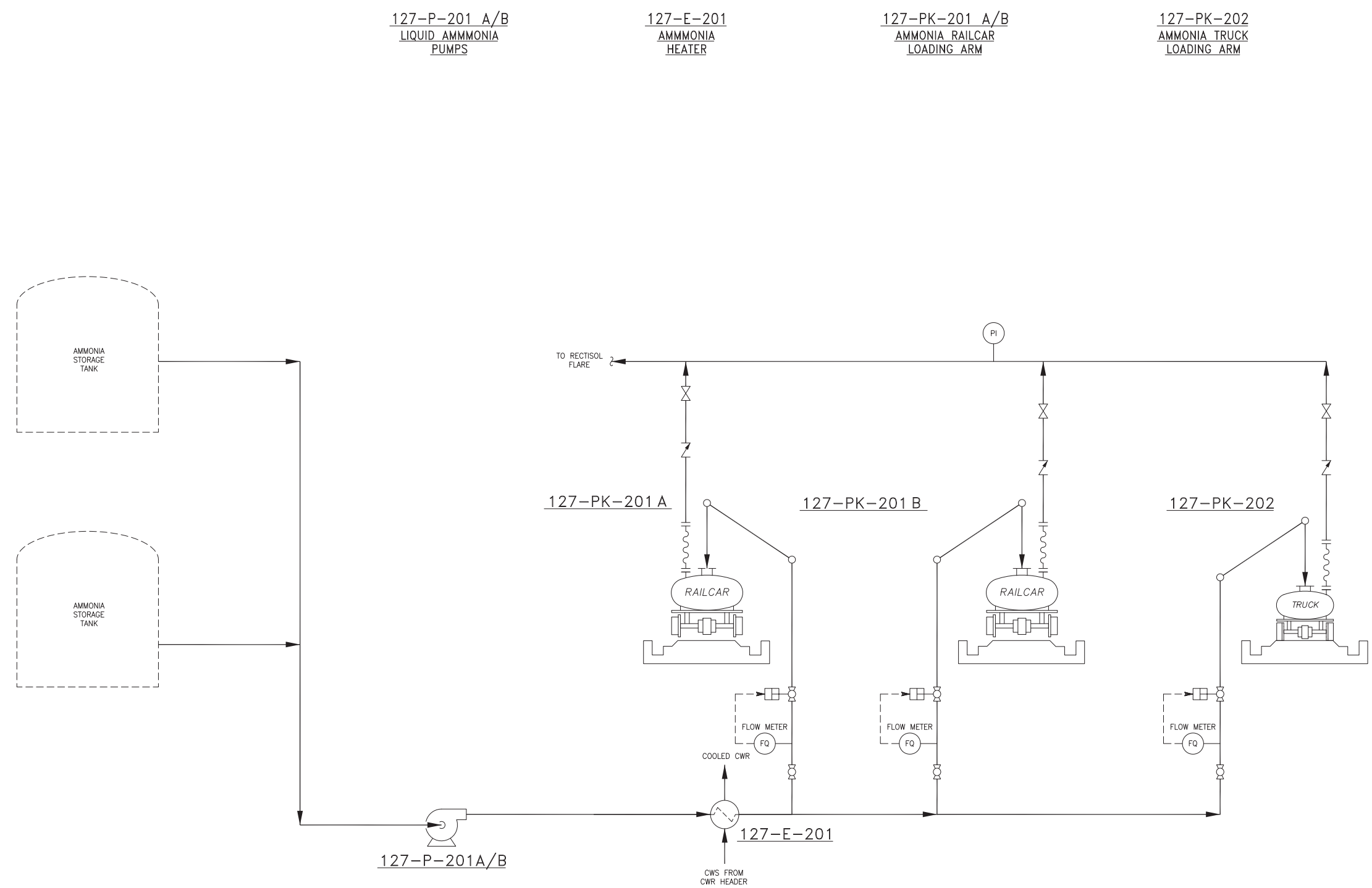
HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

PROCESS FLOW DIAGRAM
UREA RECLAIM
& LOADOUT SYSTEM

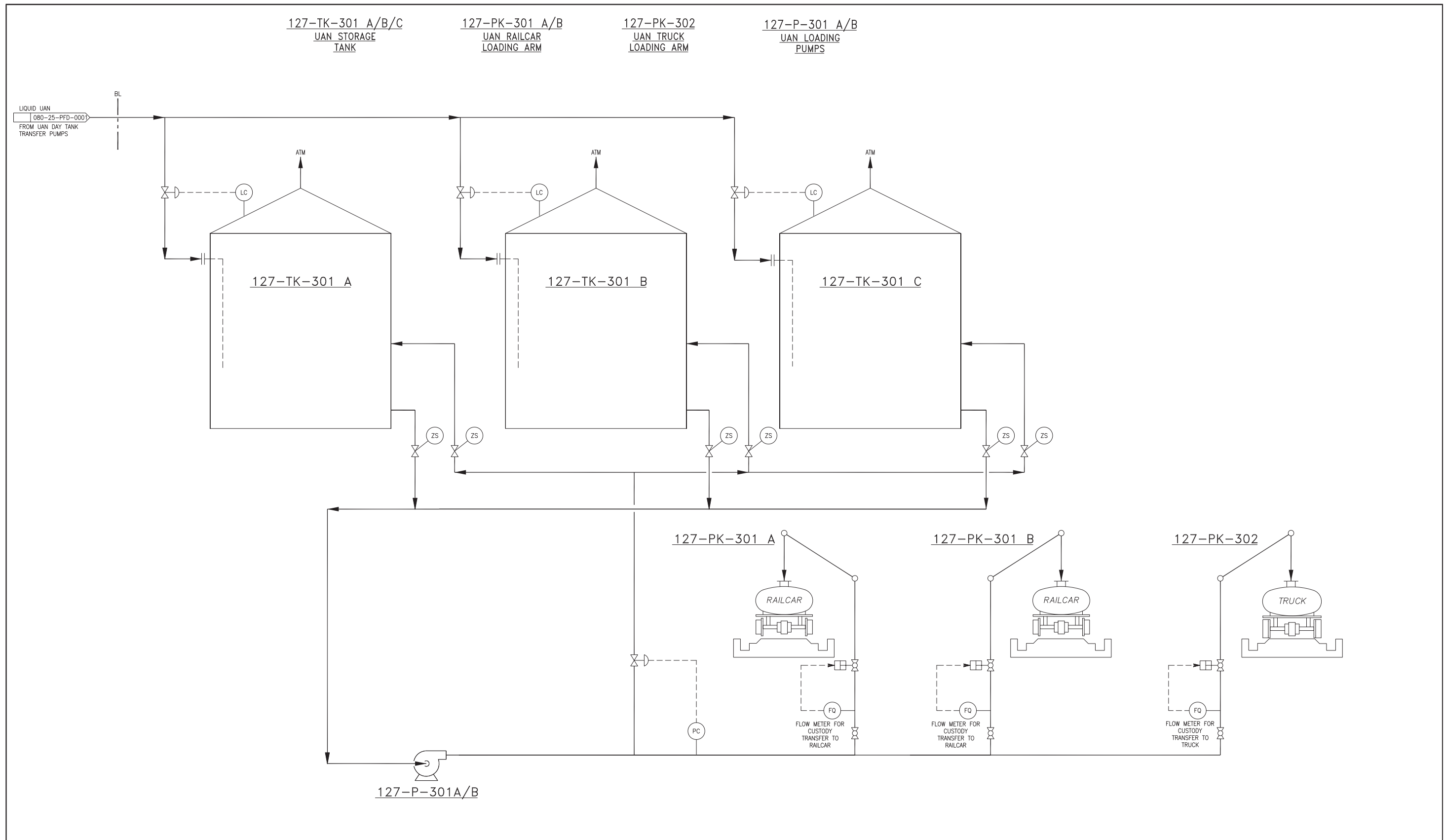
SCALE	DRAWING NUMBER
	126-59-PFD-02



Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report		HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA	
		PROCESS FLOW DIAGRAM AMMONIA VAPORIZER SYSTEM	
<i>Fluor Source Document:</i> A4UV-127-25-PFD-0101 (Rev 0, 8/29/12)		SCALE NONE	DRAWING NUMBER 127-25-PFD-0101



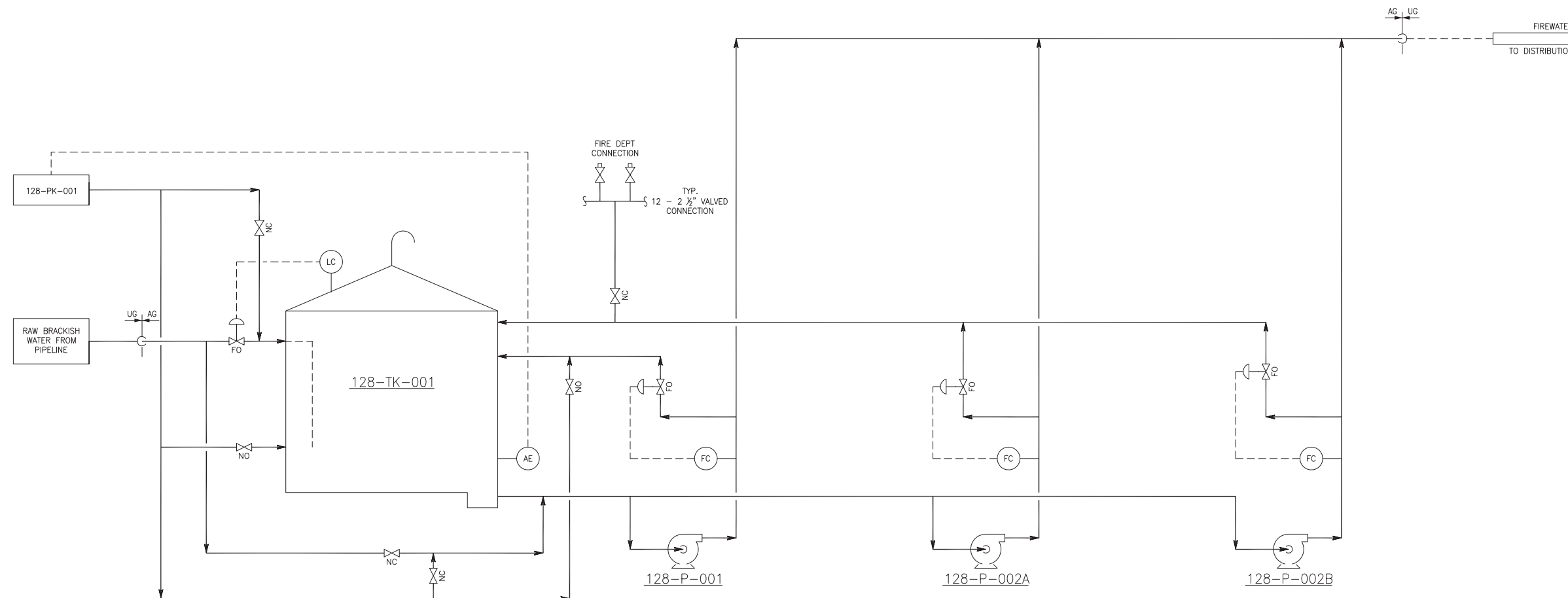
Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report <i>Fluor Source Document:</i> A4UV-127-25-PFD-0201 (Rev 0, 8/23/12)	 	HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA	
		PROCESS FLOW DIAGRAM AMMONIA LIQUID STORAGE, HANDLING & RAIL/TRUCK LOADING	
		SCALE NONE	DRAWING NUMBER 127-25-PFD-0201



Final Topical Report DE-FE0000663		HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA	
B.01 - Final Scientific & Technical Report		PROCESS FLOW DIAGRAM UREA AMMONIUM NITRATE (UAN) LIQUID STORAGE, HANDLING & RAIL/TRUCK LOADING	
<u>Fluor Source Document:</u> A4UV-127-25-PFD-0301 (Rev 0, 8/23/12)		SCALE NONE	DRAWING NUMBER 127-25-PFD-0301

128-TK-01
FIREWATER TANK

128-PK-001
SODIUM HYPOCHLORITE
INJECTION PACKAGE



128-P-001
JOCKEY PUMP
ELECTRIC

128-P-002A
FIREWATER PUMP
ELECTRIC

128-P-002B
FIREWATER PUMP
DIESEL

Final Topical Report
DE-FE0000663
B.01 - Final Scientific & Technical Report



Fluor Source Document:
A4UV-128-25-PFD-0001 (Rev 0, 8/16/12)

FLUOR®

HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

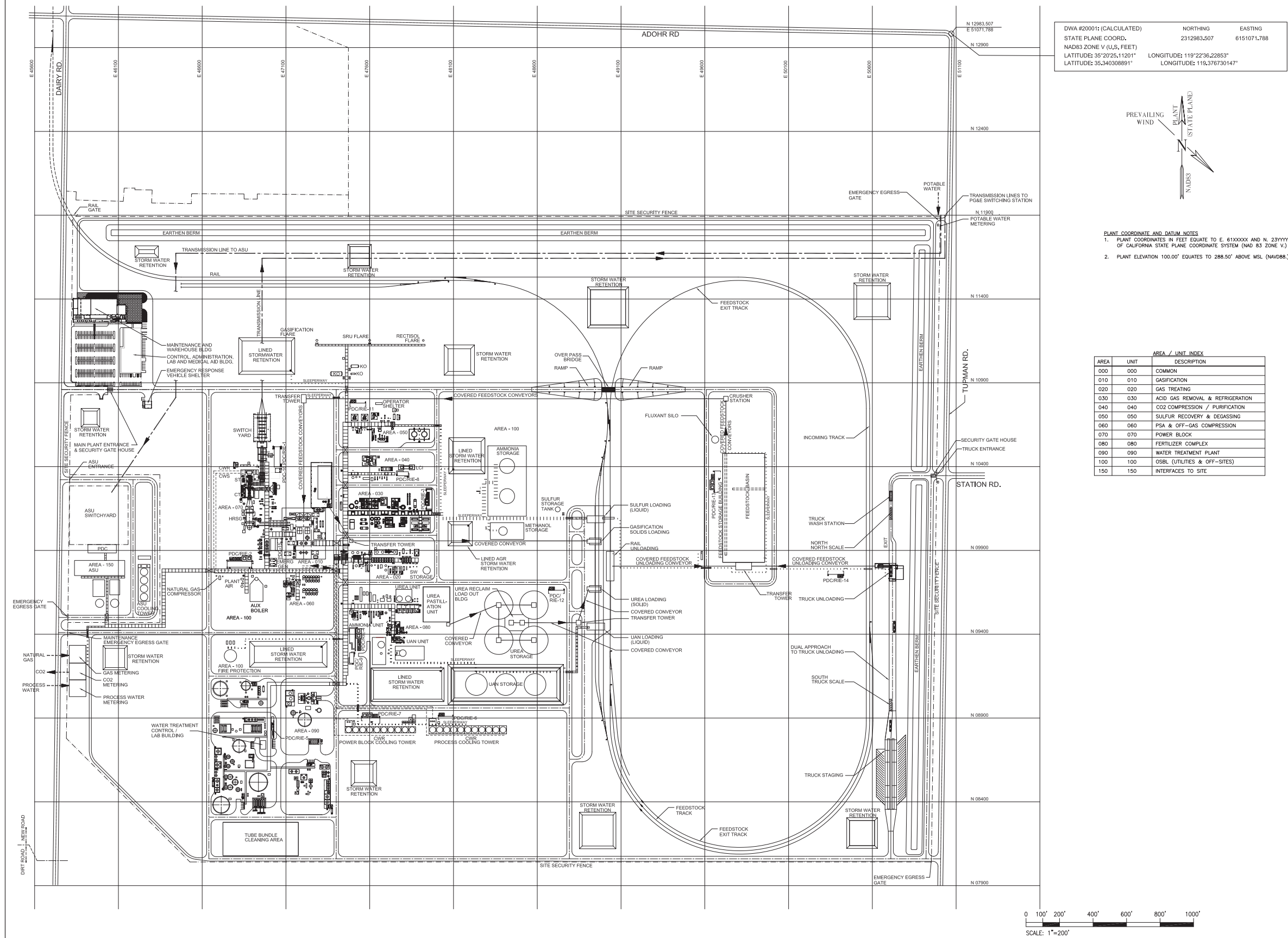
PROCESS FLOW DIAGRAM
FIREWATER SUPPLY

SCALE
NONE

DRAWING NUMBER
128-25-PFD-0001

3.9 PLOT PLAN

The Overall Plot Plan (drawing number 000-50-SK-0001) provides the general arrangement of the HECA Project's process units, material handling units, buildings, storage, and other offsite and utility systems. Battery limit utility interfaces (water, gas, CO₂, electricity) as well as site ingress and egress for personnel, feedstocks, and products are also shown. The Overall Plot Plan is included as Figure 3-8.



3.10 EQUIPMENT LIST

The Mechanical Equipment List developed during FEED for the HECA Project is provided in the pages that follow.

MECHANICAL EQUIPMENT LIST

Jul-17

Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
010				GASIFICATION									
	011 012 013	— —	180	- Feedstock Drying & Milling - Gasifier Feed System - Gasification island	MHI (Oxygen Blown Gasification) Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
020				GAS TREATING									
	020	020-TK-002	1	Sour Water Storage Tank	I.D. = 44'-0" Height = 40'-0"	Fixed Roof	N/A	2.5	212	Duplex SS 2205 or CS w/ Epoxy Lining	117,100	N/A	None
	020	020-R-001A/B	2	First Stage Reactor	I.D. = 15'-0" T/T Length = 24'-0"	Vertical	N/A	740 / FV	900 / 20 300	2-1/4 Cr 1 Mo w/ 347 WOL	377,000	60 x 17 x 17	lh
	020	020-R-002A/B	2	Second Stage Reactor	I.D. = 15'-0" T/T Length = 22'-6"	Vertical	N/A	740 / FV	650 / 20 300	2-1/4 Cr 1 Mo w/ 347 WOL	276,000	60 x 17 x 17	lh
	020	020-R-003	1	Mercury Removal Reactor	I.D. = 13'-6" T/T Length = 8'-0"	Vertical	N/A	620 / FV	250 / 300	CS	117,020	37 x 14.5 x 14.5	lh
	020	020-TK-001	1	Fresh Caustic Tank	I.D. = 18'-0" Height = 16'-0"	Vertical	N/A	5 inH20g	212	CS	17,500	17 x 19 x 19	None
	020	020-V-001	1	Syngas Scrubber	I.D. = 13'-6" T/T Length = 32'-0"	Vertical	N/A	740 / FV	850 / 300	2-1/4 Cr 1 Mo w/ 347 WOL	332,000	56 x 16 x 16	lh
	020	020-V-001-INT	1	Syngas Scrubber Internals	(4) Sieve Trays Grid Packed Bed Distributor	N/A	N/A	N/A	N/A	347 SS	17,200	N/A	N/A
	020	020-V-002	1	Syngas Scrubber KO Drum	I.D. = 13'-6" T/T Length = 20'-6"	Vertical	N/A	740 / FV	800 / 20 300	Shell: CS, clad w/ min. 0.1" 316L SS Internals: 316L SS Mesh: 316L SS	209,000	41 x 16 x 16	lh



MECHANICAL EQUIPMENT LIST

Jul-17

Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	020	020-V-003	1	Shift KO Drum #1	I.D. = 12'-6" T/T Length = 22'-0"	Vertical	N/A	670 / FV	500 / 20 300	Shell: CS Internals: CS	166,000	40 x 13.5 x 13.5	lh
	020	020-V-004	1	Shift KO Drum #2	I.D. = 11'-6" T/T Length = 23'-0"	Vertical	N/A	670 / FV	400 / 20 300	Shell: CS Internals: CS	142,000	39.5 x 12.5 x 12.5	lh
	020	020-V-005	1	Shift KO Drum #3	I.D. = 10'-0" T/T Length = 23'-0"	Vertical	N/A	670 / FV	300 / 20 300	Shell: CS Internals: CS	108,000	35.5 x 11 x 11	ls
	020	020-V-006	1	Ammonia Wash Column	I.D. = 12'-0" T/T Length = 28'-0"	Vertical	N/A	620 / FV	300 / 300	CS w/ min. 0.1" 304L SS clad/WOL	185,000	42.5 x 13 x 13	None
	020	020-V-006-INT	1	Ammonia Wash Column Internals	(6) 1-Pass Bubble Cap Trays (1) Inlet Feed Distributor	N/A	N/A	N/A	N/A	304L SS	14,000	N/A	N/A
	020	020-V-007	1	Process Condensate Receiver	I.D. = 10'-0" T/T Length = 26'-0"	Horizontal	N/A	670 / FV	400 / 20 300	Shell: CS Internals: CS	108,000	37 x 11 x 11	lh
	020	020-V-021	1	SWS Flash Drum	I.D. = 11'-6" T/T Length = 25'-0"	Horizontal	N/A	50 / FV	300 / 20 300	Shell: Duplex SS 2205 Internals: Duplex SS 2205	33,400	32 x 12.5 x 12.5	ET (top) / lh
	020	020-V-022	1	Sour Water Stripper	I.D. = 5'-6" T/T Length = 109'-0"	Vertical	N/A	50 / FV	300 / 20 300	CS w/ min. 0.1" Alloy C- 276 clad	68,800	129 x 6.5 x 6.5	lh
	020	020-V-022 INT	1	Sour Water Stripper Internals	(40) 1-Pass Valve Trays (1) Chimney Tray (6) Inlet Feed Distributors	N/A	N/A	N/A	N/A	Alloy C-276	9,100	N/A	N/A
	020	020-V-031	1	Ammonia Stripper Feed Drum	I.D. = 9'-0" T/T length = 19'-6"	Horizontal	N/A	50 / FV	300 / 20 300	Shell: CS Internals: CS	21,800	25 x 10 x 10	ET (top) / lh
	020	020-V-032	1	Ammonia Stripper	I.D. = 7'-6" T/T Length = 110'-6"	Vertical	N/A	50 / FV	300 / 20 300	CS + 1/4" CA	119,000	148 x 8.5 x 8.5	lh
	020	020-V-032 INT	1	Ammonia Stripper Internals	(35) 1-Pass Valve Trays (5) 2-Pass Valve Trays (1) Chimney Tray (3) Inlet Feed Distributors	N/A	N/A	N/A	N/A	316L SS	16,300	N/A	N/A
	020	020-V-041	1	LLP Condensate Drum	I.D. = 4'-0" T/T Length = 11'-0"	Vertical	N/A	50 / FV	300 / 20 300	Shell: CS Internals: CS	5,800	18.5 x 5 x 5	ls



MECHANICAL EQUIPMENT LIST

Jul-17

Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	020	020-V-042	1	Steam Drum	O.D. = 3'-0" T/T length = 6'-0"	Vertical	N/A	800 / FV	800 / 20 300	Shell: CS Internals: CS CA: 1/16 in	9,100	9.5 x 4 x 4	lh
	020	020-V-043	1	SWS Reboiler Condensate Drum	O.D. = 2'-6" T/T length = 4'-5 5/8"	Vertical	N/A	100 / FV	400 / 20 300	Shell: CS Internals: CS CA: 1/16 in	3,200	9.5 x 3.5 x 3.5	lh
	020	020-V-044	1	Blowdown Drum	I.D. = 4'-0" T/T Length = 13'-0"	Vertical	N/A	50 / FV	300 / 20 300	Shell: CS Internals: CS	6,320	20.5 x 5 x 5	ls
	020	020-C-001	1	Startup Gas Compressor (Package) - Includes Spillback Cooler	Capacity = 4,767 lb/min, dP = 15 psi Main Compressor: 1,500 HP Aux. LO Pump: 20 HP LO Reservoir Heater: 4.5 kW (460 V)	Integrally Geared Centrifugal (Packaged)	Induction	187.5	300 / 20	Casing: CS Impeller: SS	28,000	18 x 8 x 8	lh
	020	020-E-001A/B	2	Shift Feed/Effluent Exchanger	Duty = 36.3 MMBtu/hr	Shell and Tube / CXU	N/A	SS: 740 / FV TS: 740 / FV	SS: 900 TS: 750	SS: 1.25Cr-0.5Mo w/ 304LSS Tubes/Tubesheet: 316/316L SS dual cert. CH: CS w/ 316L SS	65,000	21 x 7 x 7	lh
	020	020-E-002	1	Startup Gas Heater	Duty = 24.6 MMBtu/hr	Shell and Tube / BHU	N/A	SS: 620 / FV TS: 800 / FV	SS: 750 TS: 800	SS: CS Tubes/Tubesheet: CS CH: CS	26,000	24 x 4.5 x 4.5	lh
	020	020-E-003 A/B	2	Process Steam Generator	Duty = 209.5 MMBtu/hr	Shell and Tube / CKU	N/A	SS: 800 / FV TS: 740 / FV	SS: 550 TS: 900	SS: CS PWHT Tubes/Tubesheet: 1.25Cr-0.5Mo w/ 347 SS CH: 1.25Cr-0.5Mo w/ 347 SS	130,000	31 x 10.5 x 10.5	lh
	020	020-E-004	1	Process Condensate Heater	Duty = 44.1 MMBtu/hr	Shell and Tube / CXU	N/A	SS: 670 / FV TS: 860 / FV	SS: 650 TS: 550	SS: 1.25Cr-0.5Mo w/ 304L SS Tubes/Tubesheet: 1.25Cr-0.5Mo CH: CS	41,000	20 x 6.5 x 6.5	lh
	020	020-E-006	1	Scrubber Feed Water Heater	Duty = 23.6 MMBtu/hr	Shell and Tube / CXU	N/A	SS: 740 / FV TS: 900 / FV	SS: 750 TS: 550	SS: 1.25Cr-0.5Mo w/ 304L SS Tubes/Tubesheet: 1.25Cr-0.5Mo CH: CS	20,000	17.5 x 5.5 x 5.5	lh
	020	020-E-007A/B/C	3	Shift LP Steam Generator	Duty = 207.0 MMBtu/hr	Shell and Tube / AKU	N/A	SS: 100 / FV TS: 670 / FV	SS: 400 TS: 650	SS: CS Tubes/Tubesheet: 1.25Cr-0.5Mo CH: 1.25Cr-0.5Mo w/ 304LSS	83,000	34.5 x 10 x 10	lh
	020	020-E-008A/B	2	Shift LLP Steam Generator	Duty = 72.3 MMBtu/hr	Shell and Tube / AKU	N/A	SS: 100 / FV TS: 670 / FV	SS: 400 TS: 500	SS: CS Tubes/Tubesheet: CS CH: CS	60,000	26.5 x 9 x 9	lh
	020	020-E-009	1	Demin Water Heater	Duty = 94.6 MMBtu/hr	Shell and Tube / CXU	N/A	SS: 670 / FV TS: 520 / FV	SS: 500 TS: 300	SS: CS Tubes/Tubesheet: 304L SS CH: 304L SS	38,000	24.5 x 6 x 6	lh



MECHANICAL EQUIPMENT LIST

Jul-17

Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	020	020-E-010A-I	9	Shift Air Cooler	Duty = 177.1 MMBtu/hr Motor Qty: 18 Rated HP: 30 HP	Air Cooled Exchanger	Half Variable Speed Half Constant Speed	670 / FV	400	CS	67,000	37 x 14 x 8	None
	020	020-E-011	1	Shift Water Cooler	Duty = 20.4 MMBtu/hr	Shell and Tube / AXU	N/A	SS: 670 / FV TS: 520 / FV	SS: 300 TS: 150	SS: CS PWHT Tubes/Tubesheet: Duplex SS 2205 CH: CS w/ Epoxy	74,000	33 x 7 x 7	None
	020	020-E-012	1	Mercury Removal Feed Preheater	Duty = 5.3 MMBtu/hr	Shell and Tube / BXU	N/A	SS: 620 / FV TS: 480 / FV	SS: 300 TS: 300	SS: CS w/ 304LSS Tubes/Tubesheet: 304L SS CH: 304L SS	8,000	14 x 4.5 x 4.5	lh
	020	020-E-013	1	Mercury Removal After Cooler	Duty = 7.1 MMBtu/hr	Shell and Tube / AXU	N/A	SS: 620 / FV TS: 480 / FV	SS: 250 TS: 150	SS: CS PWHT Tubes/Tubesheet: Duplex SS 2205 CH: CS w/ Epoxy	35,000	23 x 5.5 x 5.5	SS: lh TS: None
	020	020-E-014	1	HP BFW Cooler	Duty = 1.6 MMBtu/hr	Shell and Tube / AEU	N/A	SS: 800 / FV TS: 620 / FV	SS: 300 TS: 150	SS: CS PWHT Tubes/Tubesheet: Duplex SS 2205 CH: CS w/ Epoxy	3,900	19 x 2.5 x 2.5	None
	020	020-E-015	1	Syngas Scrubber Circulation Cooler	Duty = 0.95 MMBtu/hr	Shell and Tube / AEU	N/A	SS: 800 / FV TS: 620 / FV	SS: 400 TS: 150	SS: Duplex SS 2205 Tubes/Tubesheet: Duplex SS 2205 CH: CS w/ Epoxy	800	10 x 2 x 2	lh
	020	020-E-023	1	SWS PA Air Cooler	Duty = 13.7 MMBtu/hr Motor Qty: 2 Rated HP: 30 HP	Air Cooled Exchanger	Half Variable Speed Half Constant Speed	150 / FV	300	Alloy C-276 or Ti Gr. 2	46,000	37 x 14 x 8	Is
	020	020-E-025	1	SWS Reboiler	Duty = 17.7 MMBtu/hr	Shell and Tube / BHU	N/A	SS: 70 / FV TS: 100 / FV	SS: 300 TS: 400	SS: CS Tubes/Tubesheet: CS CH: CS	23,000	26 x 4.5 x 4.5	lh
	020	020-E-026	1	Stripped SW Air Cooler	Duty = 8.4 MMBtu/hr Motor Qty: 2 Rated HP: 15 HP	Air Cooled Exchanger	Half Variable Speed Half Constant Speed	150 / FV	300	CS	28,000	37 x 9.5 x 8	Is
	020	020-E-031	1	Ammonia Stripper Feed Preheater	Duty = 8.0 MMBtu/hr	Shell and Tube / AEU	N/A	SS: 620 / FV TS: 800 / FV	SS: 300 TS: 400	SS: CS PWHT Tubes/Tubesheet: Duplex SS 2205 CH: CS	6,200	21.5 x 2.5 x 2.5	lh
	020	020-E-033 A/B	2	Ammonia Stripper PA Air Cooler	Duty = 21.7 MMBtu/hr Motor Qty: 4 Rated HP: 25 HP	Air Cooled Exchanger	Half Variable Speed Half Constant Speed	150 / FV	300	316L SS	82,000	37 x 12.5 x 8	lh
	020	020-P-001 A/B	2	Process Condensate Pump	Capacity: 658 gpm Motor Nameplate: 200 HP Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	855	400	Casing: CS Impeller: 316 SS	5,500	9 X 5 X 6	lh
	020	020-P-002 A/B	2	Syngas Scrubber Circulation Pump	Capacity: 567 gpm Motor Nameplate: 20 HP Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	780	400	API D-1 Casing: Duplex SS 2205 Impeller: Duplex SS	2,250	8 x 5 x 6	lh



MECHANICAL EQUIPMENT LIST

Jul-17

Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	020	020-P-021 A/B	2	SWS Feed Pump	Capacity: 154 gpm Motor Nameplate: 15 HP Speed: 3600 RPM	API Horizontal Overhung / Centrifugal	Induction	130	300	API D-1 Casing: Duplex SS Internals: Duplex SS	1,450	9 X 5 X 6	lh
	020	020-P-022 A/B	2	Stripped Sour Water Pump	Capacity: 157 gpm Motor Nameplate: 15 HP Speed: 3600 RPM	API Horizontal Overhung / Centrifugal	Induction	150	300	API S-6 Casing: CS Internals: 12%Cr	1,450	9 X 5 X 6	ls
	020	020-P-023 A/B	2	SWS PA Pump	Capacity: 473 gpm Motor Nameplate: 20 HP Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	150	300	Alloy-C (Hastalloy)	2,000	7 X 3 X 4	ls
	020	020-P-024 A/B	2	Caustic Injection Pump	Capacity: 2.0 gpm Motor Nameplate: 1 HP Speed: 1800 RPM	Diaphragm Metering / Positive Displacement	Induction	150	150	CS / 316 SS	450	3 x 2.5 x 2	None
	020	020-P-031 A/B	2	Ammonia Stripper Feed Pump	Capacity: 304 gpm Motor Nameplate: 20 HP Speed: 3600 RPM	API Horizontal Overhung / Centrifugal	Induction	130	300	API Class S-8 CS / 316L SS	1,500	6 X 3 X 3	lh
	020	020-P-032 A/B	2	Stripped Process Condensate Pump	Capacity: 397 gpm Motor Nameplate: 250 HP Speed: 3600 RPM	Horizontal Between Bearings / Centrifugal	Induction	900	300	API Class S-6 CS / 12%Cr	15,000	19 x 4 x 4	lh
	020	020-P-033 A/B	2	Ammonia Stripper PA Pump	Capacity: 929 gpm Motor Nameplate: 40 HP Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	150	300	API Class S-8 CS / 316L SS	2,000	7 X 3 X 3	ls
	020	020-P-041 A/B	2	LLP Condensate Pump	Capacity:81 gpm Motor Nameplate: 20 HP Speed: 3600 RPM	Horizontal Overhung / Centrifugal	Induction	240	265	Class S-4 CS / CS	920	5 x 2 x 2	lh
	020	020-P-044 A/B	2	Blowdown Pump	Capacity: 48 gpm Motor Nameplate: 10 HP Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	150	300	API Class S-4 CS / CS	1,500	6 x 3 x 5	ls
	020	020-EJ-001	1	Startup Ejector	Capacity: 60,000 ft3 Motive Fluid: Steam	Evacuation Type, Critical Compression Ejector	N/A	Steam: 700 Air / N2: 103 - 752 mmHgA	Steam: 750 Air / N2: Ambient	316 SS	200	8 x 2 x 2	lh
	020	020-MX-001	1	Fresh Caustic Tank Mixer	No. Impellers: 2 Dia. Impellers: 65 inch Nameplate Power: 5 hp	Top Entering	Induction	Atmospheric	150	Shaft: 316 SS Impeller: 316 SS	746	21 x 6 x 6	None
	020	020-PK-001	1	BFW / Process Condensate Chemical Injection Package: - Tote - 2 x 100% Metering Pumps (Injection Point: LP BFW Distribution Feedline) - 2 x 100% Metering Pumps (Injection Point: Process Condensate Pump Discharge)	400 gal Tote Pump Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	LP BFW : 350 Condensate: 930	140	Liq. End: 316 SS Diaph.: PTFE	4,000	10 x 8.5 x 6	None
	020	020-PK-002	1	DMDS Injection Package (Rental Unit)	Supply: 71,520 lbs	— —	— —	— —	— —	— —	23,000	40 x 8 x 12	None

MECHANICAL EQUIPMENT LIST

Jul-17

Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	020	020-PK-003	1	Startup Hydrogen Package (Rental Unit)	Supply: 1.3 MMSCF Flow Rate: 100,000 SCFH	— —	— —	210	300	— —	— —	— —	None
030				ACID GAS REMOVAL & REFRIGERATION									
	031	— —	76	Acid Gas Removal	Linde (Rectisol): Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
	031	031-V-051	1	Atmospheric Condensate Flash Drum	I.D. = 5'-0" T/T Length = 17'-0"	Vertical	N/A	50	310	CS + 1/8"CA	9,700	23 x 6 x 6	PF (to HLL)
	031	031-E-051	1	Wastewater Cooler	Duty = 0.41 MMBtu/hr	Shell and Tube / AEU	N/A	SS: 100 TS: 150	SS: 350 TS: 150	SS: CS TS: Duplex SS	1,000	19 x 3 x 3	Is
	031	031-P-051 A/B	2	Wastewater Pump I	Capacity: 8 GPM Nameplate Power: 1 HP Speed: 3600 RPM	General Service Horizontal Overhung / Centrifugal	Induction	160	350	Casing: CS Impeller: 12% Cr	75	2 x 1 x 1.5	1h-ET(W)
	031	031-P-052 A/B	2	Wastewater Pump II	Capacity: 15 GPM Nameplate Power: 2 HP Speed: 3600 RPM	General Service Horizontal Overhung / Centrifugal	Induction	150	150	Casing: CS Impeller: 12% Cr	100	3 x 1 x 1.5	1h-ET(W)
	031	031-P-053 A/B	2	Condensate Pump	Capacity: 171 GPM Nameplate Power: 50 HP Speed: 3600 RPM	ANSI Vertical In-Line / Centrifugal	Induction	240	265	Casing: CS Impeller: 12% Cr	3500	2.5 x 2.5 x 8	1h-ET(W)
	031	031-SU-051	1	Methanol Slop Vessel Pit	Dimensions (L x W x H): 32 ft x 16 ft x 16 ft	— —	— —	— —	— —	— —	— —	— —	— —
	032	032-V-201	1	Refrigerant Storage Vessel	I.D. = 11'-0" T/T Length = 32'-6"	Horizontal	N/A	350	250 / -54	LTCS	82,500	39 x 12 x 12	None
	032	032-PK-001	1	AGR Refrigeration Package. Includes: - Centrifugal Compressor & Motors - Refrigerant Receiver Skid - Economizer/Sub-Coolers - Suction Knock-Out Drums - Lubrication System - Vibration Detection System - Surge Control System	2 x 50% Centrifugal Compressors: Duty: 2860 TR, -40 deg F 4 stages, 55" Casing Main Compr Motor Nameplate Pwr: 10,000 HP Aux. LO Pump Motor Nameplate Pwr: 7.5 HP	Centrifugal	Induction	325	250	Vendor Standard SA106CS, Duplex SS Tubes, LTCS, 304 SS	Compressor Skid: 191,000 each Condensor/Receiver Skid: 212,000 each Subcooler Skid: 65,000 each Suction Trap Skid: 58,000 each	Compressor Skid: 40 x 14 x 14 each Condenser/Receiver Skid: 41 x 12 x 27 each Subcooler Skid: 26 x 15 x 17 each Suction Trap Skid: 41 x 12 x 16 each	1h & 1c where needed

Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
040				CO2 COMPRESSION / PURIFICATION									
	040	040-R-001 A/B	2	Methanol Removal Reactor	I.D. = 10'-0" T/T Length = 17'-8"	Vertical	N/A	700 / FV	570 / 20	CS + 1/16" CA Internals: 304L SS	98,000	32 x 11 x 11	lh
	040	040-R-002	1	COS & H2S Removal Reactor	I.D. = 10'-0" T/T Length = 18'-0"	Vertical	N/A	550 / FV	420 / 20	CS + 1/16" CA Internals: 304L SS	79,300	32 x 11 x 11	lh
	040	040-V-001	1	CO2 Purification Compressor Suction Drum	I.D. = 7'-0" T/T Length = 16'-6"	Vertical	N/A	100	160 MDMT = -20	Shell: CS + 1/16"CA Internals: CS + 1/16"CA	11,800	23.5 x 8 x 8	None
	040	040-V-002	1	MP CO2 Compressor Suction Drum	I.D. = 10'-0" T/T Length = 19'-6"	Vertical	N/A	100	160 MDMT = -20	Shell: CS + 1/16"CA Internals: CS + 1/16"CA	24,800	29 x 11 x 11	None
	040	040-V-003	1	LP CO2 Compressor Suction Drum	I.D. = 13'-6" T/T Length = 22'-9"	Vertical	N/A	100	160 MDMT = -20	Shell: CS + 1/16"CA Internals: CS + 1/16"CA	50,300	35 x 14.5 x 14.5	None
	040	040-V-004	1	MP Condensate Flash Drum	I.D. = 3'-0" T/T Length = 8'-3"	Vertical	N/A	435	500 / 20	Shell: CS Internals: CS	5,500	13 x 4 x 4	lh
	040	040-C-001	1	CO2 Purification Compressor	Flow = 3,344 lbmol/hr dP = 430 psi Main Compressor: 8,900 HP Main LO Pump: 20 HP Aux. LO Pump: 20 HP LO Reservoir Heater: 20 kW (460 V)	Horizontal / Centrifugal	Induction	556	525 / 20	Compressor = vendor standard Intercooler tubes = Duplex SS 2205	Compressor Skid: 186,700 Lube Oil Console: 17,500 LO Rundown Tank: 750	Compressor Skid: 38 x 12 x 13 Lube Oil Console: 21 x 12 x 7 LO Rundown Tank: 9 x 4 x 4	Is
	040	040-C-002	1	EOR CO2 Compressor	LP CO2 Flow = 9,138 lbmol/hr MP CO2 Flow = 8,311 lbmol/hr dP = 2,575 psi	Integrally Geared Centrifugal	Synchronous / LCI Soft Starter	Suct. = 100 Disch. = 2,920	Suct. = 160 Disch. = 350 MDMT = 20	Compressor = vendor standard Inter & aftercoolers tubes = vendor standard	— —	— —	Is
	040	040-E-001	1	CO2 Purification Compressor Intercooler	Duty = 9.2 MMBtu/hr	Shell and Tube / AGU	N/A	SS: 330 TS: 255	SS: 390 TS: 150	SS: CS + 1/8"CA CH: CS Epoxy lined Tubes: 2205 SS TS: 2205 SS	15,000	22 x 7 x 7	None
	040	040-E-002	1	CO2 Purification Compressor After Cooler	Duty = 10.9 MMBtu/hr	Shell and Tube / AGU	N/A	SS: 550 TS: 425	SS: 420 TS: 150	SS: CS + 1/8"CA CH: CS Epoxy lined Tubes: 2205 SS TS: 2205 SS	18,200	21 x 6 x 6	None
	040	040-E-003	1	COS/H2S Reactor Feed Cross Heat Exchanger	Duty = 4.5 MMBtu/hr	Shell and Tube / AEU	N/A	SS: 550 TS: 550	SS: 420 TS: 420 MDMT: 20	SS: CS + 1/8"CA CH: CS Epoxy lined Tubes: 2205 SS TS: 2205 SS	7,000	16 x 4 x 4	lh

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Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	040	040-E-004	1	COS/H2S Reactor Feed Heater	Duty = 4.9 MMBtu/hr	Shell and Tube / BEU	N/A	SS: 435 TS: 550	SS: 500 TS: 420 MDMT: 20	SS: CS + 1/8"CA TS: CS + 1/8"CA CH: CS + 1/4"CA	6,600	12 x 4 x 4	lh
	040	040-E-005	1	CO2 Purification Cooler	Duty = 4.8 MMBtu/hr	Shell and Tube / AGU	N/A	SS: 550 TS: 425	SS: 270 TS: 125 MDMT: 20	SS: CS + 1/8"CA TS: Duplex SS 2205 CH: CS w/ Epoxy	15,000	21 x 5 x 5	lh
	040	040-E-006	1	Nitrogen Cross Heat Exchanger	Duty = 0.80 MMBtu/hr	Shell and Tube / BEU	N/A	SS: 700 TS: 700	SS: 570 TS: 570 MDMT: 20	SS: CS + 1/8"CA TS: CS + 1/8"CA Tubesheet: CS + 1/4"CA	1,700	11 x 3 x 3	lh
	040	040-E-007	1	Nitrogen Heater (Electric)	Duty = 0.94 MMBtu/hr Design kW: 360 kW	Process/Inline Electric Heater Horizontal On saddles	N/A	700	750 MDMT = 20	Shell: CS + 1/8"CA Heating Element: Alloy 840	Heater: 3,255 Control Panel: 1,000	Heater: 13 x 2 x 3.5 Control Panel: 8 x 8 x 1.5	lh
050				SULFUR PLANT									
	051	— —	28	Sulfur Recovery	Fluor Sulfur: Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
	051	051-TK-001	1	Fresh Caustic Tank	I.D. = 30'-0" Height = 32'-0"	Fixed Roof	N/A	2.5 psig / -1.5 inH2Og	200	CS	65,000	N/A	Is
	051	051-TK-002	1	Spent Caustic Tank	I.D. = 30'-0" Height = 32'-0"	Fixed Roof	N/A	2.5 psig / -1.5 inH2Og	243	CS	65,000	N/A	PF
	051	051-V-004	1	H2S Scrubber	Contacting Section: I.D. = 6'-0" Sump Section: I.D. = 16'-0" Overall T/T Length = 61'-9"	Vertical	N/A	100 / FV	243 / 300	Shell: CS + 1/8" CA, PWHT Internal: CS + 1/8" CA Trays: 410S SS	99,200	79 x 17 x 17	Is
	051	051-V-004 INT	1	H2S Scrubber Internals	(10) 1-Pass Baffle Trays	N/A	N/A	N/A	N/A	410S SS	1,000	N/A	N/A
	051	051-E-010A-B	2	Spent Caustic Cooler	Duty = 17.01 MMBtu/hr Motor Qty: 4 Rated HP: 20 HP	Air Cooled Exchanger	Two Adjustable Speed, Two Fixed Speed.	100 / FV	243	CS	79,000	37 x 11 x 9	N/A
	051	051-P-004	1	Fresh Caustic Pump	Capacity: 600 GPM Nameplate Power: 40 HP Speed: 1800 RPM	ANSI Horizontal Overhung Repeller / Centrifugal	Induction	60	120	Casing: CS Impeller: 12%CR	1,660	5.5 x 2 x 2.5	PF
	051	051-P-005	1	Caustic Circulation Pump	Capacity: 130 GPM Motor Nameplate: 7.5 HP Speed: 1800 RPM	ANSI Horizontal Overhung / Centrifugal	Induction	100	195	Class S-8 (NACE) Casing: CS Imp: 316L SS	575	4.5 x 1.5 x 2	Is

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	051	051-P-006	1	Spent Caustic Loading Pump	Capacity: 220 GPM Nameplate Power: 5 HP Speed: 1800 RPM	ANSI Horizontal Overhung / Centrifugal	Induction	100	243	Class S-6 Casing: CS Impeller: 12% Cr	620	4 x 1.5 x 2	PF
	051	051-P-007	1	H2S Scrubber Pump	Capacity: 1130 GPM Nameplate Power: 50 HP Speed: 1800 RPM	ANSI type Mag-Drive Horizontal Overhung / Centrifugal	Induction	100	200	Class S-8 (NACE) Casing: CS Impeller: 316L SS	925	5 x 2 x 2	PF / Is
	051	051-EJ-002 A/B/C/D	4	Caustic Solution Jet Mixer	3" Figure 268 Tank Mixing Eductor Capacity:138 GPM (each)	Venturi	N/A	Atmospheric	Ambient	316 SS	50	2 x 1 x 1	None
	051	051-F-001	1	Carbon Canister	Flow: 703 lb/h containing up to 100 ppm H2S	Vertical	N/A	6	180	CS	1,000	4 x 4 x 5	None
	052	— —	13	Tail Gas Unit	Fluor Sulfur: Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
	052	052-V-007	1	Condensate Flash Drum	I.D. = 3'-6" T/T Length = 9'-6"	Vertical	N/A	100 / FV	400 / 400	Shell: CS Internals: CS	4,300	16 x 4.5 x 4.5	lh
	052	052-V-008	1	Condensate Collection Drum	I.D. = 3'-6" T/T Length = 10'-0"	Vertical	N/A	50 / FV	265 / 265	Shell: CS Internals: CS	4,400	16.5 x 4.5 x 4.5	lh
	052	052-V-009	1	Boiler Blowdown Drum	I.D. = 3'-6" T/T Length = 14'-0"	Vertical	N/A	50 / FV	265 / 265	Shell: CS Internals: CS	5,240	20.5 x 4.5 x 4.5	Is
	052	052-R-002 - 052-BL-001 A/B/C - 052-VS-001	1	Thermal Oxidizer System (052-R-002): - Thermal Oxidizer Air Blower (052-B-001 A/B/C) - Stack (052-VS-001)	<u>Vapor Phase Flowrates (lb/hr)</u> SRU Trip: 954 TGU Trip: 30,140 Start-Up/Shutdown: 10,526 TGU Comp. Trip: 23,360 Rated HP: 75 HP	Horizontal/ Thermal Oxidizer	Induction	Oxidizer Shell: 0.5 Stack: Atmospheric	Oxidizer Shell: 650 (metal) Stack: 650	Oxidizer Shell: CS Stack Shell: CS with refractory lining	173,600	N/A	lh
	052	052-P-003 A/B	2	Blowdown Drum Pump	Capacity: 20 GPM Motor Nameplate: 5 HP Speed: 3600 RPM	ANSI Horizontal Overhung / Centrifugal	Induction	100	240	Casing: CS Impeller: 12Cr	550	3.5 x 2 x 2	Is
	052	052-P-004 A/B	2	Condensate Return Pump	Capacity: 20 GPM Motor Nameplate: 20 HP Speed: 3600 RPM	API Horizontal Overhung / Centrifugal	Induction	240	240	Casing: CS Impeller: 12%Cr	1,460	6 x 3 x 3	lh
	052	052-PK-004	1	Phosphate Injection Skid: - Tote - 2 x 100% Metering Pumps (Injection Point: LP BFW Header) - 2 x 100% Metering Pumps (Injection Point: HP BFW Header)	400 gal Tote Pump Capacity (LP BFW): 0.24 gph Pump Capacity (HP BFW): 0.48 gph Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	LP: 350 HP: 1610	LP: Ambient HP: Ambient	Liq. End: 316 SS Diaph.: PTFE	4,000	10 x 8.5 x 6	None



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060				PSA & OFF-GAS COMPRESSION									
	060	060-V-001	1	PSA #1 Feed KO Drum	I.D. = 6'-0" T/T Length = 10'-0"	Vertical	N/A	620	160 MDMT = -20	Shell: CS + 1/16" CA Internals: CS + 1/16" CA	17,150	15 x 6.5 x 6.5	None
	060	060-V-002	1	PSA #1 Off-Gas Compressor First Interstage KO Drum	I.D. = 7'-6" T/T Length = 13'-6"	Vertical	N/A	245	300 / 20	Shell: CS + 1/16" CA Internals: CS + 1/16" CA	15,000	17.5 x 7.5 x 7.5	None
	060	060-C-001	1	PSA #1 Off-Gas Compressor - Two (2) Compressor Casings - Three (3) Compression Stages	Flow = 6,583 lbmol/hr dP = 450 psi Main Compressor: 20,000 HP Main LO Pump: 30 HP Aux. LO Pump: 30 HP LO Reservoir Heater: 30 kW (460 V)	Horizontal / Centrifugal	Synchronous	725	Max = 380 MDMT = 20	Mfgr's Std	Compressor Skid: 300,000 lbs; Lube Oil Console: 17,500 lbs.; LO Rundown Tank: 750 lbs.	Compressor Skid: 49 x 12 x 13 Lube Oil Console: 21 x 12 x 7 LO Rundown Tank: 9 x 4 x 4	Is
	060	060-C-002	1	PSA #2 Off-Gas Compressor	Flow = 5,101 lbmol/hr dP = 57 psi Main Compressor: 6,600 HP Main LO Pump: 20 HP Aux. LO Pump: 20 HP LO Reservoir Heater: 20 kW (460 V)	Horizontal / Centrifugal	Induction	94	MDMT = 20	Mfgr's Std	Compressor Skid: 133,000 lbs; Lube Oil Console: 17,500 lbs.; LO Rundown Tank: 750 lbs.	Compressor Skid: 33 x 9 x 14 Lube Oil Console: 21 x 12 x 7 LO Rundown Tank: 9 x 4 x 4	Is
	060	060-E-001	1	PSA #1 Off-Gas Compressor Intercooler #1	Duty = 1.1 x 8.5 MMBtu/hr	Shell and Tube / AHU	N/A	SS: 245 TS: 190	SS: 300 TS: 150	SS: CS + 1/8" CA TS: Duplex SS	13,000	26 x 5 x 5	Is
	060	060-E-002	1	PSA #1 Off-Gas Compressor Intercooler #2	Duty = 1.1 x 10.0 MMBtu/hr	Shell and Tube / AHU	N/A	SS: 390 TS: 300	SS: 330 TS: 150	SS: CS + 1/8" CA TS: Duplex SS 2205	15,000	20 x 7 x 7	Is
	060	060-E-003	1	PSA #1 Off-Gas Compressor Intercooler #3	Duty = 1.1 x 9.9 MMBtu/hr	Shell and Tube / AHU	N/A	SS: 535 TS: 415	SS: 330 TS: 150	SS: CS + 1/8" CA TS: Duplex SS	14,000	24 x 5 x 5	Is
	060	060-E-004	1	PSA #1 Off-Gas Compressor Aftercooler	Duty = 1.1 x 10.1 MMBtu/hr	Shell and Tube / AHU	N/A	SS: 670 TS: 515	SS: 325 TS: 150	SS: CS TS: Duplex SS	15,000	24 x 5 x 5	Is
	060	060-E-005	1	PSA #2 Off-Gas Compressor Spillback Cooler	Duty = 11.1 MMBtu/hr	Shell and Tube / AHU	N/A	SS: 160 TS: 150	SS: 460 TS: 150	SS: CS + 1/8" CA TS: Duplex SS	13,000	26 x 5 x 5	Is
	060	060-F-001 A/B/C/D	4	PSA #1 Off-Gas Filter	Flow = 70,040 lbs/hr (each)	Horizontal	N/A	100	125 MDMT = 20	Shell: CS + 1/16" CA Internal: SS	19,900	12 x 10 x 10	None
	060	060-F-002 A/B/C/D	4	PSA #2 Off-Gas Filter	Flow = 68,660 lbs/hr (each)	Horizontal	N/A	100	125 MDMT = 20	Shell: CS + 1/16" CA Internal: SS	19,900	12 x 10 x 10	None



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	060	060-PK-001	1	Pressure Swing Adsorption Package #1 Including: Adsorber Vessels Switching Valves and Piping Skid Offgas Surge Drum H2 Product Filter Interconnecting Piping between Adsorber Vessels and Valve Skid	Feed Rate = 186.4 MMSCFD H2 Recovery = 87.5% 99.9% H2 in Product Gas Outlet H2S < 0.1 ppmv	N/A	N/A	Adsorber Vessels and H2 Product Filter - 620 psig Offgas Surge Drum 50 psig /FV	Adsorber Vessels and H2 Product Filter - 250°F MDMT = 0°F Offgas Surge Drum 0°F / 250°F	C S with 1/16" CA	(12) Adsorber - 110,000 each Offgas Surge Drum - 79,000 (2) Valve Skid - 75,000 each Filter - 3,500	(12) Adsorber - 39.6 x 12.5 x 12 each Offgas Surge Drum - 109 x 14 x 14 (2) Valve Skid - 63 x 13.5 x 13.5 each Filter - 8 x 3.5 x 3	None
	060	060-PK-002	1	Pressure Swing Adsorption Package #2 Including: Adsorber Vessels Switching Valves and Piping Skid Offgas Surge Drum H2 Product Filter Interconnecting Piping between Adsorber Vessels and Valve Skid	Feed Rate =56.38 MMSCFD H2 Recovery = 52% 99.9% H2 in Product Gas Outlet H2S < 0.1 ppmv	N/A	N/A	Adsorber Vessels and H2 Product Filter - 620 psig Offgas Surge Drum 50 psig /FV	Adsorber Vessels and H2 Product Filter - 250°F MDMT = 0°F Offgas Surge Drum 0°F / 250°F	C S with 1/16" CA	(10) Adsorber - 84,000 each Offgas Surge Drum - 79,000 (2) Valve Skid - 60,000 each Filter - 3,500	(10) Adsorber - 36.3 x 11.5 x 121 each Offgas Surge Drum - 109 x 14 x 14 (2) Valve Skid - 50.5 x 12.5 x 12.5 each Filter - 8 x 3.5 x 3	None
070				POWER BLOCK									
	071	071-GT-001	1	Combustion Turbine Intake Air Filter and Evap Cooler TCA Cooler GT Cooling Air Filter GT 2C Cooler GT Sealing Air Filter Main Oil Tank, Cooler and Pumps HP Control Oil Tank, Cooler and Pumps GT Water Injection Pump GT Enclosure GT Ignitor GT Air Compressor Washing System	Proprietary MHI Equipment	— —	— —	— —	— —	— —	— —	— —	— —
	071	071-GT-002	1	Generator	Proprietary MHI Equipment	— —	— —	— —	— —	— —	— —	— —	— —
	071	071-ST-001	1	Steam Turbine HP-IP Turbine LP Turbine Gland Steam Condenser Gland Exhauster Seal Oil Unit Lube Oil Skid	Proprietary MHI Equipment	— —	— —	— —	— —	— —	— —	— —	— —
	071	071-E-001	1	TCA Startup Air Cooler	Duty = 16.5 MMBtu/hr Motor Qty: 2 Rated HP: 25 HP	Air Cooled Exchanger	Induction 1 Constant Speed, 1 VFD	3,010	335	CS	70,000	37 x 12 x 9	None
	071	071-DS-001	1	UHP to HP Steam Desuperheater	Inlet Steam: 440,900 lb/hr, 740 psia, 967 °F Outlet Steam: 488,000 lb/hr, 735 psia, 750 °F Inlet BFW: 47,100 lb/hr, up to 1,300 psia, 250 °F	Annular Venturi	N/A	800	1020	9Cr -1Mo - V (Alloy Steel A335 Gr P91 Pipe Ring)	1,700	5 x 4 x 4	1h



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	071	071-DS-002	1	HHP to HP Steam Desuperheater	Inlet Steam: 219,100 lb/hr, 740 psia, 797 °F Outlet Steam: 224,200 lb/hr, 735 psia, 750 °F Inlet BFW: 5,100 lb/hr, up to 1,300 psia, 250 °F	Annular Venturi	N/A	800	850	1.25Cr -0.5Mo (Alloy Steel A335, Gr P11 Pipe Ring)	580	5 x 3 x 3	lh
	071	071-DS-003	1	HP to MP Steam Desuperheater	Inlet Steam: 277,900 lb/hr, 405 psia, 718 °F Outlet Steam: 325,000 lb/hr, 400 psia, 445 °F Inlet BFW: 47,100 lb/hr, up to 1,300 psia, 250 °F	Annular Venturi	N/A	435	770	CS	820	5 x 3 x 3	lh
	071	071-DS-004	1	MP to LP Steam Desuperheater	Inlet Steam: 90,700 lb/hr, 74.5 psia, 350 °F Outlet Steam: 92,500 lb/hr, 69.5 psia, 308 °F Inlet BFW: 1,800 lb/hr, up to 220 psia, 105 °F Pressure drop at maximum flow specified: 3.0 PSI	Annular Venturi	N/A	100	400	CS Pipe Spec: NA1	350	5 x 2 x 2	lh
	071	071-DS-005	1	GSC Steam Desuperheater	Inlet Steam: 2,800 lb/hr, 125 psia, 689 °F Outlet Steam: 3,000 lb/hr, 120 psia, 500 °F Inlet BFW: 220 lb/hr, up to 220 psia, 105 °F	Annular Venturi	N/A	150	770	CS	35	2 x 2 x 2	lh
	071	071-DS-006	1	Gland Steam Desuperheater	Inlet Steam: 1,400 lb/hr, 25 psia, 300 °F Outlet Steam: 1,500 lb/hr, 25 psia, 275 °F Inlet Condensate: 125 lb/hr, 220 psia, 105 °F	Annular Venturi	N/A	150	500	CS	40	2 x 2 x 2	lh
	072	072-B-001 - 072-PK-001 - 072-PK-002 - 072-PK-003 - 072-V-001 - 072-V-002	1	Heat Recovery Steam Generator (072-B-001): - SCR Ammonia Flow Control Unit Skid (072-PK-001) - Duct Burner Aux/Cooling Air Blower Skid (072-PK-002) - Duct Burner BMS (072-PK-003) - UHP Steam Drum (072-V-001) - MP Steam Drum (072-V-002) - SCR / CO Catalyst - Continuous Emissions Monitoring System (CEMS) - Exhaust Stack	On-Peak: GTG Exhaust Gas: 5,322,000 lb/hr @ 945°F UHP Steam: 533,900 lb/hr 1,917 psia @ 1,031°F HRH Steam: @ 1,031°F MP Steam: 154,300 lb/hr @ 466 psia LP Steam: 146,100 lb/hr 70 psia @ 527°F Off-Peak: GTG Exhaust Gas: 3,994,000 lb/hr @ 977°F UHP Steam: 440,500 lb/hr 1,622 psia @ 1,055°F HRH Steam: @ 1,056°F MP Steam: 94,430 lb/hr @ 420 psia LP Steam: 115,800 lb/hr 71 psia @ 523°F AFCU Blower Motors: 30 hp (each) Cooling Air Blower Motor: 20 hp (each) Upper level platform Hoist Motor: 1 hp	Horizontal / HRSG	Induction	UHP: 2,120 RH: 455 MP: 480 LP: 80	UHP: 1,100 RH: 1,100 MP: 500 LP: 570	Mfgr's Std	The HRSG will have an estimated 3 skids in addition to the main unit.	Plot Area: 168' Lx50' W Stack height: 213 ft	lh
	073	073-V-001	1	HRSG Blowdown Drum	I.D. = 11'-0" T/T Length = 15'-0"	Vertical	N/A	50	750	Shell: CS Internals: CS	31,400	25.5 x 12 x 12	Is
	073	073-V-002	1	Atmospheric Blowdown Drum	I.D. = 6'-0" T/T Length = 8'-0"	Vertical	N/A	50	750	Shell: CS Internals: CS	8,310	14 x 7 x 7	Is
	073	073-V-003	1	Closed Cooling Water Head Tank	I.D. = 3'-0" T/T Length = 7'-0"	Vertical	N/A	160	300	Shell: 304L SS Internals: 304L SS	3,690	12 x 4 x 4	None



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	073	073-E-001 073-EJ-001 073-EJ-002	1	Surface Condenser (Water Cooled) - Steam Jet Air Ejector (073-EJ-001) - Hogger (073-EJ-002)	HEI Design Standards Duty = 938.5 MMBtu/hr Steam Flow Rate: 976,600 lbs/hr at Q = 0.93 CW Flow Rate = 93,000 gpm	Water Cooled Surface Condenser	N/A	SS: FV / 15 TS: 75	SS: 300 TS: 150	• Hotwell: CS • Tubes: Duplex SS 2205 • Tubesheet: Duplex SS 2205 • Baffle: 304 SS • CH: CS with epoxy or rubber lining and CP anodes 073-EJ-001: CS 073-EJ-002: Manufacturer's Standard.	327,000	43 X 27 X 29	None
	073	073-E-004	1	Clean Syngas Performance Heater	Duty = 34.2 MMBtu/hr	Shell and Tube / CXU	N/A	SS: 1,240 TS: 1,610	SS: 360 TS: 500	SS: CS Tubes: CS Tubesheet: CS Baffles: CS CH: CS	59,000	28 x 7 x 7	lh
	073	073-E-005	1	Nitrogen Diluent Performance Heater	Duty = 20.5 MMBtu/hr	Shell and Tube / CXU	N/A	SS: 1,240 TS: 1,610	SS: 390 TS: 500	SS: CS Tubes: CS Tubesheet: CS Baffles: CS CH: CS	40,000	27 x 6 x 6	lh
	073	073-E-007 A/B	2	Closed Cooling Water Heat Exchanger	Duty = 29.6 MMBtu/hr	Plate and Frame	N/A	HS: 160 CS: 75	150	Plates: 6% Mo SuperAust SS or Ti Gr 1 or 2 Frame: CS	10,300	109 x 46 x 113	None
	073	073-E-009	1	BFW Back-Up Steam Heater	Duty = 42.27 MMBtu/hr	Shell and Tube	N/A	SS: 1,610 / FV TS: 1,610	SS: 500 / 300 (FV) TS: 450	SS: CS Tubes: CS Tubesheet: CS Baffles: CS CH: CS	17,100	17 x 7.5 x 7.5	lh
	073	073-P-001A/B	2	Condensate Pump	Capacity: 2,750 GPM Nameplate Power: 600 HP Speed: 1800 RPM	Vertical Can / Centrifugal	Induction	330	155	Class: S-6 Casing: CS Impeller: 12% Cr	1,700	3.5 x 3.5 x 27	None
	073	073-P-002A/B	2	UHP Boiler Feedwater Pump	Capacity: 1,238 GPM BFW Pump Nameplate Power: 3000 HP LO Pump Nameplate Power: 5 HP LO Heater: 2kW Speed: 3600 RPM	Horizontal Multistage Between- Bearing, Top-Top / Centrifugal	Induction	3,180 @ 110°F / 3,010 @ 310°F	310	Class: S-6 Casing: CS Impeller: 12% Cr	33,800	25.5 x 7 x 9.5	lh



MECHANICAL EQUIPMENT LIST

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Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	073	073-P-003A/B	2	HHP / LP Boiler Feedwater Pump	HHP Capacity: 2,560 GPM LP Bleed Capacity: 725 GPM Total Capacity: 3,285 GPM BFW Pump Nameplate Power: 2,800 HP LO Pump Nameplate Power: 5 HP LO Heater: 2kW Speed: 3600 RPM	Horizontal Multistage Between-Bearing, Top-Top w/ Interstrage Bleed / Centrifugal	Induction	1,700 @ 110°F / 1,610 @ 305°F	305	Class: S-6 Casing: CS Impeller: 12% Cr	39,000	25.5 x 7 x 9.5	lh
	073	073-P-005	1	Oily / Water Sump Pump	Flow: 75 GPM Nameplate Power: 10 HP Speed: 3600RPM	General Service Vertical Sump Pump / Centrifugal	Induction	50	150	Class: S-6 Casing: CS Impeller: 12% Cr	732	2 x 2 x 12	None
	073	073-P-006A/B	2	Closed Cooling Water Pump	Capacity: 4,021 GPM Nameplate Power: 350 HP Speed: 1800 RPM	General Service Horizontal Between-Bearing, Side-Side Inline / Centrifugal	Induction	160	150	Class: S-6 Casing: CS Impeller: 12% Cr	9,000	9.0 x 3.5 x 3.5	None
	073	073-P-007 A/B	2	HRSB Blowdown Sump Pump	Capacity: 650 GPM Nameplate Power: 50 HP Speed: 1800 RPM	General Service Vertical Sump / Centrifugal	Induction	100	140	Class: S-6 Casing: CS Impeller: 12% Cr	1,460	2.5 x 2.5 x 17.5	None
	073	073-P-008	1	BFW Condensate Pump	Capacity: 145 GPM Nameplate Power: 200 HP Speed: 3600 RPM	High-Speed Vertical In-Line / Centrifugal	Induction	1,700 @ 110°F / 1,610 @ 500°F	500	Class: S-6 Casing: CS Impeller: 12% Cr	4,320	4 x 4 x 9	lh
	073	073-BL-001	1	High Temperature Flue Gas Blower	Flow: 332,000 ACFM Nameplate Power: 800 HP	Centrifugal	Induction	+25 in. WC / -64.2 in WC	715	Housing: CS IMP: CS	48,000	4 pcs 15 x 6 x 20 15 x 6 x 20 9 x 20 x 14	lh
	073	073-BL-002	1	Low Temperature Flue Gas Blower	Flow: 138,059 ACFM Nameplate Power: 350 HP	Centrifugal	Induction	+25 in. WC / -64.2 in WC	350	Housing: CS IMP: CS	23,000	4 pcs 15 x 6 x 20 15 x 6 x 20 9 x 20 x 14	lh
	073	073-DA-001	1	High Temperature Flue Gas Damper	Flow: 331,957 ACFM Nameplate Power: 25 HP	Round	Induction	+25 in. WC / -64.2 in WC	715	CS Frame SS Blade and Seals	12,500	10 x 2 x 24	lh
	073	073-DA-002	1	Low Tempertaure Flue Gas Damper	Flow: 138,059 ACFM Nameplate Power: 15 HP	Round	Induction	+25 in. WC / -64.2 in WC	360	CS Frame SS Blade and Seals	10,000	10 x 2 x 24	lh
	073	073-DU-001	1	HighTemperature Flue Gas Duct From HRSB to HT Flue Gas Damper	Flow: 331,957 ACFM 78 inch diameter	N/A	N/A	+25 in. WC / -64.2 in WC	715	CS	10,500	3 pcs 6.5 dia ell 6.5 dia ell 1 red 112 in x 78 in	lh
	073	073-DU-002	1	HighTemperature Flue Gas Duct From Damper to HT Flue Gas Blower	Flow: 331,957 ACFM 78 inch diameter	N/A	N/A	+25 in. WC / -64.2 in WC	715	CS	13,681	2 pcs 13 x 8 each	lh
	073	073-DU-003	1	HighTemperature Flue Gas Duct From HT Flue Gas Blower to Gasifier	Flow: 331,957 ACFM 72 inch diameter	N/A	N/A	+25 in. WC / -64.2 in WC	715	CS	51,000	7 pcs 7 dia x 5 6 dia x 35 (5 pcs) 6 dia ell	lh

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	073	073-DU-004	1	Low Temperature Flue Gas Duct From HRSG to Damper	Flow: 138,059 ACFM 60 inch diameter	N/A	N/A	+25 in. WC / -64.2 in WC	360	CS	9,500	5 pcs 2 x 5 dia ell 2 x 5 dia ell 1 x 60" x 48" reducer	lh
	073	073-DU-005	1	Low Temperature Flue Gas Duct From Damper to LT Flue Gas Blower	Flow: 138,059 ACFM 60 inch diameter	N/A	N/A	+25 in. WC / -64.2 in WC	360	CS	7,000	2 pcs 13 x 8 each	lh
	073	073-DU-006	1	Low Temperature Flue Gas Duct From LT Flue Gas Blower to Gasifier	Flow: 138,059 ACFM 60 inch diameter	N/A	N/A	+25 in. WC / -64.2 in WC	360	CS	50,000	7 pcs 7 dia x 5 5 dia x 35 (5 pcs)	lh
	073	073-DU-00EXJNT	Lot	Expansion Joint	High and Low Temperature Flue Gas Duct	N/A	N/A	Same as duct	Same as duct	EPDM or Flexon	1000 x 16 items	2 boxes 5 x 5 x 5 5 x 5 x 5	lh
	073	— —	1	Low and High Temperature Flue Gas Ductwork Insulation	High and Low Temperature Flue Gas Duct	N/A	N/A	N/A	N/A	Mineral Wool or Acoustic	N/A	N/A	Acoustic at fan and lh remainder
	073	073-E-008	1	Natural Gas Electric Heater	Flow ÷ 105,800 lb/hr Design kW: 387 kW	Process/Inline Electric Heater Horizontal On saddles	N/A	620	150	Shell: CS + 1/8"CA Heating Element: Alloy 840	Heater: 2495 Control Panel: 1000	Heater: 13 x 2 x 3 Control Panel: 8 x 8 x 1.5	lh
	073	073-F-001	1	Natural Gas Filter / Separator	Flow: 104,800 lb/hr	Vertical Vessels Only	N/A	620	150	Shell: CS Internals: SS	1,850	10 x 3 x 3	lh
	073	073-F-002	1	Clean Syngas DB Filter / Separator	Flow: 10,600 lb/hr	Vertical Vessels Only	N/A	100	150	Shell: CS Internals: SS	1,850	10 x 3 x 3	None
	073	073-F-003	1	Offgas DB Filter / Separator	Flow: 89,300 lb/hr	Vertical Vessels Only	N/A	100	150	Shell: CS Internals: SS	3,145	10 x 5 x 4	None
	073	073-F-004	1	Clean Syngas Filter / Separator	Flow: 149,900 lb/hr	Horizontal Vessel with Sump	N/A	620	360	Shell: CS Internals: SS	10,000	20 x 6 x 10	lh
	073	073-F-005	1	Nitrogen Diluent Filter / Separator	Flow: 641,100 lb/hr	Horizontal Vessel with Sump	N/A	575	390	Shell: CS Internals: SS	18,000	30 x 8 x 12	lh
	073	073-F-006	1	UHP BFW Pump Duplex Strainer	Flow: 1,265 GPM	Vertical	N/A	125	310	Shell: CS Internals: 304 SS	3,500	10 x 3 x 8	lh
	073	073-F-007	1	HHP / LP BFW Pump Duplex Strainer	Flow: 3,245 GPM	Vertical	N/A	125	310	Shell: CS Internals: 304 SS	7,000	14 x 5 x 11	lh
	073	073-PK-001	1	Phosphate Injection Skid: - Tote - 2 x 100% Metering Pumps (Injection Point: UHP BFW Pump Discharge)	400 gal Tote Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	3010	140	Tote: FRP or HDPE Liq. End: 316 SS Diaph.: PTFE	2,700	6 x 8.5 x 6	None
	073	073-PK-002	1	Ammonia Injection Skid: - Tote - 2 x 100% Metering Pumps (Injection Point: Condensate Pump Discharge)	400 gal Tote Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	330	140	Tote: CS Liq. End: 316 SS Diaph.: PTFE	3,000	6 x 8.5 x 6	None
	073	073-PK-003	1	Oxygen Scavenger Injection Skid: - Tote - 2 x 100% Metering Pumps (Injection Point: Deaerator)	400 gal Tote Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	150	140	Tote: CS Liq. End: 316 SS Diaph.: PTFE	3,000	6 x 8.5 x 6	None
	073	073-S-001	1	HRSG Blowdown Drum Silencer	Flow Rate: 229,000 lb/hr Silencer Inlet Line Size: 36"	Vertical	N/A	50	750	• Shell: CS or 304L SS • Internals: CS or 304L SS	6,469	18 x 6 x 6	None

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	073	073-S-002	1	Atmospheric Blowdown Drum Silencer	Flow Rate: 200,000 lb/hr Silencer Inlet Line Size: 36"	Vertical	N/A	50	750	• Shell: CS or 304L SS • Internals: CS or 304L SS	5,475	19 x 5.5 x 5.5	None
	073	073-V-004	1	Deaerator	BFW Flow Rate: 4,340 gpm Makeup Water Flow: 1,038 gpm Steam Condensate Makeup Water Flow: 514 gpm	Horizontal	N/A	50 / FV	400	• Stripping Section: CS or CS clad with 0.125" min. 304L SS • Storage Tank: CS • Internals: 410S or 304L SS • Trays: 410S or 304L SS	29,500 (Heater) 90,000 (Storage)	27 x 7.5 x 7.5 (Heater) 64 x 12 x 12 (Storage)	1h
	073	073-SU-001	1	Gas Turbine Wash Water Sump	Working Volume: 6,000 gal	— —	— —	— —	250	Concrete	— —	— —	— —
	073	073-SU-002	1	HRSB Blowdown Sump	Working Volume: 3,250 gal	— —	— —	— —	160	Concrete	— —	— —	— —
	073	073-SU-003	1	Oil / Water Sump	Working Volume: 2,000 gal	— —	— —	— —	140	Concrete	— —	— —	— —
080				FERTILIZER COMPLEX									
	080	080-V-002	1	Ammonia Synthesis Unit Blowdown Drum	I.D. = 2'-6" T/T Length = 8'-6"	Vertical	N/A	50	265	CS	2,010	13 x 3.5 x 3.5	Is
	080	080-P-001 A/B	2	Ammonia Synthesis Unit Blowdown Pump	Capacity: 8.5 GPM Nameplate Power: 7.5 HP Speed: 3600 RPM	API Horizontal Overhung / Centrifugal	Induction	120	265	API Class: S-6 Casing: CS Impeller: 12% Cr	854	4.5 x 2.5 x 2.5	Is
	080	080-PK-001 080-P-002 A/B 080-TK-001	1	Ammonia Synthesis Unit Phosphate Injection Package: - Tote - 2 x 100% Metering Pumps	400 gal Tote Capacity: 0.2 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	1610	150	Tote: FRP or HDPE Liq. End: 316 SS Diaph.: PTFE	2,700	6 x 8.5 x 6	PF
	080	080-PK-002 080-P-003 A/B 080-TK-002	1	UAN Complex Phosphate Injection Package: - Tote - 2 x 100% Metering Pumps	400 gal Tote Capacity: 0.04 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	1610	150	Tote: FRP or HDPE Liq. End: 316 SS Diaph.: PTFE	2,700	6 x 8.5 x 6	PF
	081	— —	32	Ammonia Synthesis	Ammonia Casale: Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
	081	081-S-001	1	Waste Heat Boiler Vent Silencer	Commodity: Steam Capacity: 199,352 lb/hr Silencer Inlet Line Size: 10"	Vertical	N/A	50	570	CS	4,165	18 x 5 x 5	None



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	082	— —	92	Urea Production	Urea Casale: Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
	082	082-S-001	1	CO2 Vent Silencer	Commodity: CO ₂ Capacity: 97,300 lb/hr Silencer Inlet Line Size: 10"	Vertical	N/A	50	400	304L SS	1,410	13 x 3.5 x 3.5	None
	082	082-S-002	1	LP Steam Drum Vent Silencer	Commodity: Steam Capacity: 135,000 lb/hr Silencer Inlet Line Size: 24"	Vertical	N/A	50	335	CS	3,147	11.5 x 4.5 x 4.5	None
	082	082-S-003	1	Stripper Steam Saturator Vent Silencer	Commodity: Steam Capacity: 22,000 lb/hr Silencer Inlet Line Size: 8"	Vertical	N/A	50	450	CS	902	13 x 2 x 2	None
	082	082-HT-001 A/B	2	Common East/West Monorail for servicing Pumps 082-P-702A through P-602B	Capacity: 3 ton Lift: 20 ft	Chain Fall	N/A	N/A	N/A	Mfgr's Std	500	2 x 2 x 3	None
	082	082-HT-002 A/B	2	Monorail (North/South) for servicing Pump 082-P-101 A/B and P-301 A/B	Capacity: 5 ton Lift: 20 ft	Chain Fall	N/A	N/A	N/A	Mfgr's Std	800	2 x 2.5 x 3	None
	083	083-PK-001	44	Solid Urea Production: -Urea Pastillation Package	Sandvik: Proprietary Technology Capacity: 1,720 STPD	— —	— —	— —	— —	— —	— —	— —	— —
	084	— —	78	UAN Complex	Weatherly: Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
	084	084-TK-001	1	UAN Product Start-Up Tank	I.D. = 38'-0" Height = 40'-0"	Fixed Roof	N/A	0.5 inH2Og	250	316 L SS	89,000	N/A	None
	084	084-TK-002	1	UAN Corrosion Inhibitor Tank	I.D. = 10'-0" Height = 11'-0"	Fixed Roof	N/A	0.5	120	FRP	2,600	14 x 11 x 11	None
	084	084-P-001	1	UAN Transfer Pump	Flow: 258 GPM (Demin Water) / 194 GPM (UAN) Motor Nameplate: 15 HP Operating Speed: 3600 RPM	ANSI Horizontal Overhung / Centrifugal	Induction	100	250	316L SS	991	5 x 2 x 2	None
	084	084-PK-001 084-P-002 A/B	1	UAN Corrosion Inhibitor Package: - 2 x 100% Metering Pumps	Capacity: 1.1 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	75	250	Per Manufacturer's Standard	2,700	6 x 8.5 x 6	None

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090				WATER TREATMENT PLANT									
	091	— —	88	Raw Water Treatment	Jacobs Engineering Group: Proprietary Design	— —	— —	— —	— —	— —	— —	— —	— —
	092	— —	71	Demin Water System Treatment	Jacobs Engineering Group: Proprietary Design	— —	— —	— —	— —	— —	— —	— —	— —
	093	— —	133	Wastewater Treatment	Jacobs Engineering Group: Proprietary Design	— —	— —	— —	— —	— —	— —	— —	— —
100				OSBL (UTILITIES & OFF-SITES)									
	100	100-P-001	1	Oily Water Sump Pump - Common Warehouse Spare	Capacity: 75 gpm Nameplate Power: 15 HP Speed: 3600 RPM	General Service Vertical Sump / Centrifugal	Induction	50	100	Casing: DI Impeller: CS	830	2 x 2 x 12	None
	101	101-CT-001 101-BL-001 A-J	1	Process Cooling Tower Process Cooling Tower Fans	Multicell induced draft wet cooling tower Duty = 1,115 MMBtu/hr CW Flow = 162,000 gpm Motors Qty: 10 @ 200 HP (each)	Inline, Crossflow Cooling Towers	Induction Motors VFD by Electrical	Atmospheric	100	FRP	1,351,500	N/A	None
	101	101-P-001 A/B/C	3	Process Cooling Water Pump	Capacity: 89,100 gpm Nameplate Power: 5400 HP Speed: 514 RPM	General Service Vertical Turbine / Centrifugal	Induction	150	100	Casing: CS Impeller: 12%Cr Class: S-6	114,000	9.5 x 9 x 44	None
	101	101-SU-001	1	Process Cooling Tower Basin	Holdup Time: 10 min Working Vol: 1,620,000 gal	— —	— —	— —	— —	— —	— —	— —	— —
	101	— —	1	Process Cooling Tower Pump Basin	Dimensions: 69' - 0" L x 55' - 0" W x 16' - 8" D	— —	— —	— —	— —	— —	— —	— —	— —
	101	101-F-001A/B/C/D/E/F	6	Travelling Screen	Capacity: 162,000 gpm	Vari-Flow Travelling Sump Screen	N/A	Atmospheric	100	304 SS	5,000	8 x 2 x 25	None
	102	102-V-001	1	Sulfuric Acid Storage Tank	I.D. = 10'-0" T/T Length = 14'-0"	Vertical	N/A	14	140	Shell: CS Internals: CS	17,430	23 x 11 x 11	None



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	102	102-CT-001 102-BL-001 A-G	1	Power Block Cooling Tower Power Block Cooling Tower Fans	Multicell induced draft wet cooling tower Duty = 983 MMBtu/hr CW Flow = 97,800 gpm Motors Qty: 7 @ 200 HP (each)	Inline, Crossflow Cooling Towers	Induction Motors VFD by Electrical	Atmospheric	100	FRP	921,500	N/A	None
	102	102-P-001-A/B	2	Circulating Water Pump	Capacity: 54,500 gpm Nameplate Power: 2100 HP Speed: 514 RPM	General Service Vertical Turbine / Centrifugal	Induction	75	100	Casing: CS Impeller: 12%Cr Class: S-6	50,000	7 x 7 x 33	None
	102	102-PK-001	1	Sodium Hypochlorite Injection Package	3 x 100% Metering Pump (5 gph, each) 1 x 100% Shock Metering Pump (30 gph) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	100	125	Liq. End: PVC Diaph.: PTFE	2,700	10 x 5 x 6	None
	102	102-PK-002	1	Dispersant Chemical Injection Package: - Tote - 3 x 100% Metering Pumps	400 gal Tote Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	100	125	Liq. End: 316 SS Diaph.: PTFE	2,700	8 x 8.5 x 6	None
	102	102-PK-003	1	Corrosion Inhibitor Injection Package: - Tote - 3 x 100% Metering Pumps	400 gal Tote Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	100	125	Liq. End: 316 SS Diaph.: PTFE	2,700	8 x 8.5 x 6	None
	102	102-PK-004	1	Sulfuric Acid Injection Package: - Pumps	Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	100	125	Liq. End: 316 SS Diaph.: PTFE	2,700	8 x 5 x 6	None
	102	102-SU-001	1	Power Block Cooling Tower Basin	Working Vol: 490,000 gal	— —	— —	— —	140	Concrete	— —	— —	— —
	102	102-V-002	1	Sodium Hypochlorite Tank	I.D. = 11'-0" T/T Length = 18'-0"	Vertical	N/A	14	140	Shell: CS Internals: CS	21,980	28 x 12 x 12	None
	102	102-F-001-A/B/C/D	4	CT Pit Travelling Screen	Capacity: 97,820 gpm	Vari-Flow Travelling Sump Screen	N/A	Atmospheric	100	304 SS	3,850	6 x 6 x 25	None
	102	— —	1	Power Block Cooling Tower Pump Basin	Dimensions: 69' - 0" L x 42' - 0" W x 25' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	103	103-V-001	1	LP Condensate Flash Drum	I.D. = 6'-0" Height = 12'-0"	Vertical	N/A	50	300	CS	10,770	26 x 7 x 7	Is / FP
	103	103-P-001A/B	2	LP Condensate Pump	Flow: 126 GPM Nameplate Power: 25 HP Speed: 3600 RPM	API Horizontal Overhung / Centrifugal	Induction	240	287	Casing: CS Impeller: SS	1,500	7 x 4 x 4	lh
	104	104-V-001	1	Continuous Blowdown Drum	I.D. = 5'-0" Height = 13'-0"	Vertical	N/A	100	400	CS	8,360	20 x 6 x 6	lh / FP



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	104	104-V-002	1	Intermittent Blowdown Drum	I.D. = 6'-0" Height = 18'-0"	Vertical	N/A	50	265	CS + 1/8" C.A	15,230	33 x 7 x 7	Is / FP
	104	104-B-001 -104-BL-002 A/B -104-BL-001 -104-PK-002	1 -2 -1 -1	Auxiliary Boiler (104-B-001) -Dilution Air Blower (104-BL-002 A/B) -Auxiliary Boiler Forced Draft Fan (104-BL-001) -Ammonia Flow Control Skid part of the Selective Catalytic Reduction System (104-PK-002)	150,000 lb/hr -2 x 100% Dilution Air Blower Motors: 7.5 HP ea -Forced Draft Fan Motor: 600 HP	Boiler	Induction	Furnace: 850 Screen: 850 Superheater: 850 Convection: 850 Economizer: 900	Furnace: 2,300 Screen: 2,300 Superheater: 2,200 Convection: 1,800 Economizer: 750	SA 178 A	Boiler: 287,000	Boiler: 57 x 13.67 x 18.5	lh
	104	104-P-001 A/B	2	Blowdown Pump	Capacity: 50 GPM Nameplate Power: 7.5 HP Speed: 3600 RPM	API Vertical Inline / Centrifugal	Induction	85	250	Casing: CS Impeller: 12%Cr	367	1.5 x 1.0 x 4	Is
	104	104-P-002	1	Auxiliary Boiler Oily Water Sump Pump	Capacity: 75 gpm Nameplate Power: 15 HP Speed: 3600 RPM	General Service Vertical Sump Pump / Centrifugal	Induction	50	100	Casing: DI Impeller: CS	830	2 x 2 x 12	None
	104	104-PK-001 104-P-003 A/B	1	Phosphate Injection System - 2 x 100% Metering Pumps	Capacity: 5 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	1610	150	Liq. End: 316 SS Diaph.: PTFE	2,700	6 x 5 x 6	None
	104	104-SU-001	1	Auxilliary Boiler Oily Water Sump	Dimensions: 8' - 0" L x 8' - 0" W x 10' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	105	105-DG-001 A/B	2	Emergency Diesel Generator	1,500 kW each	Horizontal	Diesel Engine	N/A	N/A	Mfgr's Std	68,003	40 x 10 x 10	Enclosure furnished with thermal and noise insulation.
	106	106-V-001	1	Air Dryer KO Drum	I.D. = 4'-0" T/T Length = 8'-0"	Vertical	N/A	175	175	CS	5,670	13 x 5 x 5	None
	106	106-V-003	1	Instrument Air Receiver	I.D. = 14'-0" T/T Length = 29'-0"	Vertical	N/A	175	175	CS	88,410	41.5 x 15 x 15	None
	106	106-C-001	1	Air Compressor (Package) - Includes Inlet Air Filter/Silencer (shipped loose) - 1st Stage Intercooler - 2nd Stage Intercooler - Discharge Cooler	Design: 5,000 SCFM dry air at 97°F, 20% RH Main Compressor: 1,500 HP Aux. LO Pump: 5 HP LO Reservoir Heater: 4 kW (460 V)	Horizontal / Integrally Geared Centrifugal (Package)	Induction	175	170	Mfgr's Std	25,000	20 x 9 x 9	None
	106	106-PK-002 106-F-002 A/B 106-V-002 A/B 106-F-003 A/B	1	Air Dryer Package (Heatless) Air Dryer Pre-filters Air Dryers Air Dryer Post Filters	Design: 5,000 SCFM wet air at 175 psig and 150 °F	N/A	N/A	175	170	CS	11,000	16'-6"" x 7'-10" x 12'-2"H	None



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	107	107-V-11	1	Gasification Flare KO Drum	I.D. = 25'-0" T/T Length = 60'-0" Boot: I.D. = 5'-0" T/T Length = 5'-0"	Horizontal Vessel with Boot	N/A	50 / FV	650	CS	306,000	N/A	Is
	107	107-V-021	1	Rectisol Flare KO Drum	I.D. = 16'-0" T/T Length = 40'-0" Boot: I.D. = 4'-0" T/T Length = 5'-0"	Horizontal Vessel with Boot	N/A	50 / FV	-50 / 300	CS w/ Clad T316L SS	92,000	48 x 17 x 17	Is
	107	107-V-031	1	SRU Flare KO Drum	I.D. = 10'-0" T/T Length = 25'-0" Boot: I.D. = 4'-0" T/T Length = 5'-0"	Horizontal Vessel with Boot	N/A	50 / FV	250	CS w/ Clad T316L SS	33,000	30 x 11 x 11	Is
	107	107-P-011A/B	2	Gasification Flare KO Drum Pump	Capacity: 55 gpm Motor Nameplate: 7.5 HP Operating Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	100	500	Casing: CS Impeller: 316L SS Class: S-8 (NACE)	1,474	6 x 3 x 3	None
	107	107-P-012A/B	2	Gasification Flare Seal Drum Pump	Capacity: 55 gpm Motor Nameplate: 7.5 HP Operating Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	100	500	Casing: CS Impeller: 316L SS Class: S-8 (NACE)	1,474	6 x 3 x 3	None
	107	107-P-021A/B	2	Rectisol Flare KO Drum Pump	Capacity: 55 gpm Motor Nameplate: 7.5 HP Operating Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	100	-50	Casing: LTCS Impeller: 316L SS Class: S-8 (modified)	1,312	6 x 3 x 3	Ic
	107	107-P-031A/B	2	SRU Flare KO Drum Pump	Capacity: 55 gpm Motor Nameplate: 7.5 HP Operating Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	100	500	Casing: CS Impeller: 316L SS Class: S-8 (NACE)	1,474	6 x 3 x 3	None
	107	107-P-032A/B	2	SRU Flare Seal Drum Pump	Capacity: 55 gpm Motor Nameplate: 7.5 HP Operating Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	100	500	Casing: CS Impeller: 316L SS Class: S-8 (NACE)	1,474	6 x 3 x 3	None
	107	107-FL-11	1	Gasification Flare	Design Flow: 1,304,110 lb/h, 286 F 250 ft height (incl Tip and Seal Drum) 60" stack diameter Integral seal drum at flare base	Vertical, Center Steam Assisted Guy Wire Supported Flare with Integral Seal Drum	N/A	50	650	Riser/Stack:A-36 CS Flare Tip: 310 SS L&P: Galvanized CS	Stack: Foundation Loads Vertical: 301 kip Shear:28.4 Kip Moment:2001-k-ft Tip: 6326 lb Pilot (each):75 lb Pilot Total: 450 lb Ignition Panel:420 lb Purge Reduction Device: 230 lb	6 sections (Flare Proper) 40 x 5 x 5 Excludes panel, piping etc.	Ih
	107	107-FL-11-V-1	1	Gasification Flare Seal Drum	Integral to Gasification Flare	Vertical	N/A	50	650	A-36 CS	Included above	36 x 12	None



MECHANICAL EQUIPMENT LIST

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Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	107	107-FL-21	1	Rectisol Flare	Design Flow: 253,457 lb/hr 36" stack diameter	Vertical, Steam Assisted Guy Wire Supported Flare	N/A	50	-50 to 400	Riser/Stack:A-36 CS Flare Tip: 310 SS L&P: Galvanized CS	Stack: Foundation Loads Vertical: 199 kip Shear:13.6 Kip Moment:587-k-ft Tip: 9100 lb Molecular Seal: 5700 lb	6 sections: 40 x 3 x 3 Molecular Seal Section is 13 feet Long and 7 feet Dia Excludes panel, piping etc.	lh
	107	107-FL-31	1	SRU Flare	Design Flow: 281,289 lb/hr, 76 F 250 ft height (incl. Tip) 30" stack diameter Integral seal drum at flare base	Vertical, Gas Assisted (Rimfire) Guy Wire Supported Flare with Integral Seal Drum	N/A	50	650	Riser/Stack:A-36 CS Flare Tip: 310 SS L&P: Galvanized CS	Stack: Foundation Loads Vertical: 224 kip Shear: 20.5 Kip Moment: 1048-k-ft Tip: 3000 lb Pilot each: 75 lb Pilot Total: 300 lb Panel: 420 lb Purge Reduction Device: 58 lb	6 sections: 40 x 2.5 x 2.5 Excludes panel, piping etc.	None
	107	107-FL-31-V-1	1	SRU Flare Seal Drum	Integral to Gasification Flare	Vertical	N/A	50	650	A-36 CS	Included above	21 x 9	None
	109	109-V-001	1	Natural Gas KO Drum	I.D. = 6'-6" T/T Length = 13'-0"	Vertical	N/A	675 / FV	150 / 300	CS	30,710	21 x 7.5 x 7.5	FP
	109	109-C-001	1	Startup Natural Gas Compressor (Package) - Includes Discharge Cooler (also for Recycle)	Flow = 2,063 lb/min Main Compressor: 4,000 HP Aux. LO Pump: 15 HP LO Reservoir Heater: Two (2) 4.5 kW (460 V)	Integrally Geared Centrifugal (Packaged)	Induction	919 (Assumed 1.25 x Oper Disch Press)	250 (est.)	Mfgr's Std	70,000	25 x 8 x 9	Is
	109	109-C-002	1	Gasifier Natural Gas Compressor	Main Compressor Motor: 60 HP LO Reservoir Heater: 750 W (120 V)	Vertical / Diaphragm	Induction	1,000	400	Mfgr's Std	7,000	10 x 5 x 8	Is
	113	113-P-001	1	L2 Storm Water Sump Pump	Capacity: 75 gpm Nameplate Power: 10 HP Speed: 3600 RPM	General Service Vertical Sump Pump / Centrifugal	Induction	100	150	Casing: DI Impeller: CS	670	2 x 2 x 12	None
	113	113-P-002	1	L4 Storm Water Sump Pump	Capacity: 75 gpm Nameplate Power: 7.5 HP Speed: 3600 RPM	General Service Vertical Sump Pump / Centrifugal	Induction	100	150	Casing: DI Impeller: CS	670	2 x 2 x 12	None
	113	113-P-003	1	L5 Storm Water Sump Pump	Capacity: 75 gpm Nameplate Power: 7.5 HP Speed: 3600 RPM	General Service Vertical Sump Pump / Centrifugal	Induction	100	150	Casing: DI Impeller: CS	670	2 x 2 x 12	None



MECHANICAL EQUIPMENT LIST

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Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	113	113-P-004	1	L6 Storm Water Sump Pump	Capacity: 75 gpm Nameplate Power: 10 HP Speed: 3600 RPM	General Service Vertical Sump Pump / Centrifugal	Induction	100	150	Casing: DI Impeller: CS	670	2 x 2 x 12	None
	113	113-P-005	1	L12 Storm Water Sump Pump	Capacity: 75 gpm Nameplate Power: 7.5 HP Speed: 3600 RPM	General Service Vertical Sump Pump / Centrifugal	Induction	100	150	Casing: DI Impeller: CS	670	2 x 2 x 12	None
	113	113-SU-001	1	L2 Lined Storm Water Retention Basin	Dimensions: 295' - 0" L x 180' - 0" W x 10' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	113	113-SU-002	1	L4 Lined Storm Water Retention Basin	Dimensions: 455' - 0" L x 165' - 0" W x 11' - 7.2" D	— —	— —	— —	— —	— —	— —	— —	— —
	113	113-SU-003	1	L5 Lined Storm Water Retention Basin	Dimensions: 105' - 0" L x 105' - 0" W x 10' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	113	113-SU-004	1	L6 Lined Storm Water Retention Basin	Dimensions: 215' - 0" L x 215' - 0" W x 11' - 6" D	— —	— —	— —	— —	— —	— —	— —	— —
	113	113-SU-005	1	L12 Lined Storm Water Retention Basin	Dimensions: 435' - 0" L x 200' - 0" W x 7' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	114	114-P-001 A/B	2	West Wash Down Water Pump	Capacity: 75 gpm Nameplate Power: 2 HP Speed: 1800 RPM	General Service Vertical Sump / Centrifugal	Induction	65	100	Casing: DI Impeller: CS	685	2 x 2 x 12	None
	114	114-P-002 A/B	2	East Wash Down Water Pump	Capacity: 75 gpm Nameplate Power: 3 HP Speed: 1800 RPM	General Service Vertical Sump / Centrifugal	Induction	75	100	Casing: DI Impeller: CS	685	2 x 2 x 12	None
	114	114-F-001 A/B	2	West Dual Trash Screen	Flow Rate: 75 gpm	Sump Screen	N/A	Atmospheric	150	304 SS	250	5x10x1	None
	114	114-F-002 A/B	2	East Dual Trash Screen	Flow Rate: 75 gpm	Sump Screen	N/A	Atmospheric	150	304 SS	250	5x10x1	None
	114	114-HT-001	1	West Monorail and Chain Hoist	Capacity: 3 ton Lift: 20 ft	Chain Fall	N/A	N/A	N/A	Mfgr's Std	500	2 x 2 x 3	None
	114	114-HT-002	1	East Monorail and Chain Hoist	Capacity: 3 ton Lift: 20 ft	Chain Fall	N/A	N/A	N/A	Mfgr's Std	500	2 x 2 x 3	None

MECHANICAL EQUIPMENT LIST

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Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	114	114-SU-001	1	West Wash Down Settling Sump	Dimensions: 50' - 0" L x 10' - 0" W (2 x 5'-0" channels) x 10' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	114	114-SU-002	1	East Wash Down Settling Sump	Dimensions: 50' - 0" L x 10' - 0" W (2 x 5'-0" channels) x 10' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	115	115-P-001	1	North Oily Water Sump Pump	Capacity: 75 gpm Nameplate Power: 7.5 HP Speed: 3600 RPM	General Service Vertical Sump / Centrifugal	Induction	50	100	Casing: DI Impeller: CS	670	2 x 2 x 12	None
	115	115-P-002	1	South Oily Water Sump Pump	Capacity: 75 gpm Nameplate Power: 7.5 HP Speed: 3600 RPM	General Service Vertical Sump / Centrifugal	Induction	50	100	Casing: DI Impeller: CS	670	2 x 2 x 12	None
	115	115-SU-001	1	North Oily Water Sump	Dimensions: 8' - 0" L x 8' - 0" W x 10' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	115	115-SU-002	1	South Oily Water Sump	Dimensions: 8' - 0" L x 8' - 0" W x 10' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	115	115-SU-003	1	Exchanger Area Oily Water Sump	Dimensions: 10' - 0" L x 10' - 0" W x 5' - 0" D	— —	— —	— —	— —	— —	— —	— —	— —
	120	120-P-001	1	Gasification Flare Low Point Collection Pump	Capacity: 28 gpm Nameplate Power: 10 HP Speed: 1800 rpm	API Horizontal Overhung / Centrifugal	Induction	100	200	Casing: CS Impeller: CS	1,500	6 x 3 x 5	PF
	123 124 126	— —	211	- Rail & Truck Feedstock Unloading, Handling & Storage -Gasification Solids Storage, Handling & Rail / Truck Loading -Urea Pastilles Solids Storage, Handling & Rail / Truck Loading	Solid Materials Handling Package: Proprietary Design	— —	— —	— —	— —	— —	— —	— —	— —
	125	125-TK-001	1	Degassed Sulfur Tank	I.D. = 30'-0" Height = 24'-0"	Fixed Roof	N/A	8 / 4 inH2Og	350	CS	96,500	N/A	CT-lh
	125	125-P-001 A/B	2	Sulfur Loading Pump	Capacity: 285 gpm Nameplate Power: 15 HP Speed: 1800 RPM	API Horizontal Overhung / Centrifugal	Induction	100	360	Casing: CS Impeller: 316L SS	3,500	7 x 4 x 3.5	lh - ST
	125	125-EJ-001A/B	2	Railcar Loading Arm Ejector	Fluid: Sulfur Vapor + Air Quantity of Fluid to Ejector: 100 to 200 lb/hr	Special jacketed jet gas compressor Ejector	N/A	360	436-439	316L SS	65	3 x 1 x 1	lh
	125	125-EJ-002	1	Truck Loading Arm Ejector	Fluid: Sulfur Vapor + Air Quantity of Fluid to Ejector: 100 to 200 lb/hr	Special jacketed jet gas compressor Ejector	N/A	360	436-439	316L SS	65	3 x 1 x 1	lh

MECHANICAL EQUIPMENT LIST

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Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	125	125-PK-001 A/B	2	Sulfur Railcar Loading Arms	Capacity: 285 gpm 4" Supported Boom, Top Loading Arm	Down Feed Right hand Left Hand	N/A	150	400	Arm: CS Seals: PTFE Gangway: Galv. CS	Arm: 1200 Gangway: 750	Arm: 12 x 4 x 5 Gangway: 9 x 4 x 2 Cage: 10 x 8 x 2	lh
	125	125-PK-002	1	Sulfur Truck Loading Arm	Capacity: 285 gpm 4" Supported Boom, Top Loading Arm	Down Feed Right hand	N/A	150	400	Arm: CS Seals: PTFE Gangway: Galv. CS	Arm: 1200 Gangway: 750	Arm: 12 x 4 x 5 Gangway: 9 x 4 x 2 Cage: 7 x 5 x 4	lh
	127	— —	5	Ammonia Storage Support System	Ammonia Casale: Confidential Licensed Technology	— —	— —	— —	— —	— —	— —	— —	— —
	127	127-TK-001A/B	2	Ammonia Storage Tank	I.D. = 90'-0" Height = 53'-0"	Dome Roof	N/A	2.5 / -4.0 inH2Og	170 / -27.4	LTCS	823,000	N/A	lc
	127	127-TK-301A/B/C	3	UAN Storage Tank	I.D. = 130'-0" Height = 48'-0"	Fixed Roof	N/A	2.5 / -1.5 inH2Og	180	CS with Epoxy Lining	727,000	N/A	None
	127	127-E-201	1	Ammonia Heater	Duty = 8.67 MMBtu/hr	Shell and Tube / BEU	N/A	SS: 150 TS: 290	SS: 150 TS: 125 MDMT SS: 20 MDMT TS: -50	SS: CS TS: LTCS	7,000	25 x 4 x 4	lc
	127	127-P-101	1	Anhydrous Ammonia Booster Pump	Capacity: 1 gpm Nameplate Power: 3/4 HP Speed: 1800 RPM	Diaphragm Metering / Positive Displacement	Induction	150	-50	LTCS	460	3 x 2.5 x 2	lc
	127	127-P-201A/B	2	Ammonia Loading Pump	Capacity: 223 gpm Nameplate Power: 25 HP Speed: 1800 RPM	API Vertical Can / Centrifugal	Induction	300	-50	Casing: LTCS Impeller: LTCS	1,900	2 x 2 x 14.5	lc
	127	127-P-301A/B	2	UAN Loading Pump	Capacity: 385 gpm Nameplate Power: 25 HP Speed: 1800 rpm	ANSI Vertical In-line / Centrifugal	Induction	100	150	Casing: CS Impeller: 316 SS	1,160	2.5 x 2 x 5.5	None
	127	127-PK-101 127-E-101 A/B 127-V-101	1	Ammonia Vaporizer Package Electric Ammonia Vaporizers Ammonia Surge Vessel	Capacity: 275 lb/hr 2 x 100%, 60kW Bayonet Style Vaporizers Heaters 480V/3ph/60Hz service 1 x 100% Accumulator Vessel	Skid Mounted	No	260	-50 / 115	CS	6,000	12 x 8 x 8	lc
	127	127-PK-201 A/B	2	Ammonia Railcar Loading Arm	Capacity: 245 gpm 4" Supported Boom, Top Loading Arm	Down Feed Right hand Left Hand	N/A	300	-50	Arm: CS Seals: PTFE Gangway: Galv. CS	Arm: 850 Gangway: 750	Arm: 12 x 4 x 5 Gangway: 9 x 4 x 2 Cage: 10 x 8 x 2	None
	127	127-PK-202	1	Ammonia Truck Loading Arm	Capacity: 245 gpm 4" Supported Boom, Top Loading Arm	Down Feed Right hand	N/A	300	-50	Arm: CS Seals: PTFE Gangway: Galv. CS	Arm: 750 Gangway: 750	Arm: 10 x 4 x 5 Gangway: 9 x 4 x 2 Cage: 7 x 5 x 4	None
	127	127-PK-301A/B	2	UAN Railcar Loading Arm	Capacity: 385 gpm 4" Supported Boom, Top Loading Arm	Down Feed Right hand Left Hand	N/A	100	150	Arm: CS Seals: PTFE Gangway: Galv. CS	Arm: 850 Gangway: 750	Arm: 12 x 4 x 5 Gangway: 9 x 4 x 2 Cage: 10 x 8 x 2	None

MECHANICAL EQUIPMENT LIST

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Area	Unit Number	Equipment Tag	Qty	Description	Design Conditions	Orientation / Type	Motor/Driver Type/Adjustable Speed?	Design Pressure (Int/Ext) psig	Design Temp Int(max/min)/Ext °F	Material	Est. Weight (each tag) (Empty) lbs	Total Shipping Dimensions L x W x H ft	Insulation
	127	127-PK-302	1	UAN Truck Loading Arm	Capacity: 385 gpm 4" Supported Boom, Top Loading Arm	Down Feed Right hand	N/A	100	150	Arm: CS Seals: PTFE Gangway: Galv. CS	Arm: 750 Gangway: 750	Arm: 10 x 4 x 5 Gangway: 9 x 4 x 2 Cage: 7 x 5 x 4	None
	128	128-TK-001	1	Firewater Tank	I.D. = 74'-0" Height = 40'-0"	Fixed Roof	N/A	2.5 / -1.5 inH2Og	150	Shell: CS w/ Epoxy Lining, CA = 0 in.	256,000	N/A	None
	128	128-TK-002	1	Sodium Hypochlorite Tank	I.D. = 6'-0" Height = 12'-0"	Fixed Roof	N/A	0.5	125	FRP	1,780	15 x 7 x 7	None
	128	128-P-001	1	Jockey Pump	Capacity: 325 gpm Nameplate Power: 40 HP	General Service Vertical Inline / Centrifugal	Induction		100	Casing: Duplex SS Impeller: Duplex SS	675	2 x 2 x 4.5	None
	128	128-P-002 A	1	Firewater Pump Electric	Capacity: 3,000 gpm Nameplate Power: 300 HP Speed: 1800 rpm	Horizontal, Between- bearing, Side-side (In- Line) / Centrifugal	Induction		100	Casing: Duplex SS Impeller: Duplex SS	82,000	13 x 4 x 4	None
	128	128-P-002 B	1	Firewater Pump Diesel	Capacity: 3,000 gpm Engine BHP Rating: 327 HP Speed: 1750 rpm	Horizontal, Between- bearing, Side-side (In- Line) / Centrifugal	N/A		100	Casing: Duplex SS Impeller: Duplex SS	10,200	14.5 x 6 x 7.5	None
	128	128-PK-001 128-P-003 A/B	1	Sodium Hypochlorite Injection Package - 2 x 100% Metering Pumps	Capacity: 8 gph (each) Nameplate Power: 1.5 hp (each)	Skid Mounted System	Induction	100	120	Liq. End: PVC Diaph.: PTFE	2,500	8 x 8.5 x 6	None

3.11 CAPITAL COST ESTIMATE & BASIS

The Capital Cost Basis of Estimate that follows describes how the Modified Class 3 EPC Capital Cost Estimate that is included herein was prepared for the HECA Project during FEED.

3.11.1 General

The content of the estimate is a Modified Class 3 EPC Capital Cost Estimate for the HECA Project. The estimate was developed utilizing estimating systems owned and licensed by Fluor including Aspen's Capital Cost EstimatorTM (CCE - version 7.3), ICESM and MS Office Products TM.

The Modified Class 3 estimate is defined as follows:

- For the majority of Process Units, the estimate aligns with a Class 3 Capital Cost Estimate as defined in AACE International Recommended Practice No. 18R-97.
- Due to HECA LLC requirements dictated in Fluor's FEED Contract, certain units were estimated utilizing a reduced level of engineering detail. In some instances the supporting engineering was limited by the availability of project-specific supplier and / or licensor data.

The purpose of the estimate is to provide a "financial baseline" for HECA LLC to secure project financing. The estimate entails the engineering, procurement, construction and commissioning of an IGCC "polygeneration" project located on a 453 acre "grass roots" site near Tupman, CA.

A. Scope of Estimate

The HECA Project's Capital Cost Estimate is comprised of the facilities identified below and described elsewhere within this Report. The estimate has been summarized into the Project's four (4) major functional areas as designated on the Overall Block Flow Diagram (provided in Section 3.2):

Functional Area 1: Hydrogen-Rich Fuel Production

- Gasification
- Gas Treating
- Acid Gas Removal & Refrigeration
- CO₂ Compression & Purification
- Sulfur Plant
- PSA & Off-Gas Compression

Functional Area 2: Power Production

- Gas Turbine, Steam Turbine, and Generator
- Heat Recovery Steam Generator
- Surface Condenser and Balance of Plant

Functional Area 3: Fertilizer Manufacturing Complex

- Ammonia Synthesis
- Urea Unit
- Solid Urea (Pastilles) Production
- UAN Complex

Functional Area 4: Common Facilities

The Common Facilities encompasses the Outside Battery Limits (OSBL) including Utilities & Offsites and all units outside of the above Process Areas:

- Water Treatment Plant
- Cooling Water System - Process
- Cooling Water System – Power Block
- Recovered Condensate System
- Auxiliary Boiler
- Emergency Diesel Generators

-
- Plant and instrument Air Systems
 - Flare Systems
 - Natural Gas Distribution System
 - Storm Water System / Storm Water Retention Ponds
 - Solids Handling Drainage Systems
 - Oily Water Sewer
 - Rail / Truck Feedstock Unloading, handling & Storage
 - Sulfur Liquid Storage, Handling & Rail / Truck Loading
 - Ammonia / Methanol / UAN Storage, Handling & Rail / Truck Loading
 - Firewater / Fire Protection System

B. Estimate Content, Scope and Methods

The content of the estimate is a Modified Class 3 EPC Capital Cost Estimate for the HECA Project. The estimate was developed utilizing estimating systems owned and licensed by Fluor including Aspen's Capital Cost EstimatorTM (CCE - version 7.3), ICESM and MS Office Products TM.

This Basis of Estimate explains the key components of the estimate including quantity development, labor costs, material costs, equipment costs, indirect costs, productivity adjustment, wage rates, taxes and contingency. The allowances, assumptions, clarifications and exclusions made in the development of the estimate are listed.

Direct field costs reflect a direct hire union shop construction execution strategy, with some specific specialty subcontract construction work included. The basis for the development of direct field labor is the Fluor Estimating Standard Unit Work Hours, adjusted to reflect the site-specific conditions.

C. General Assumptions and Qualifications

- The estimate does not include any work associated with removal of contaminated materials, hazardous waste or artifacts that may be encountered. This includes handling, removal, disposal and remediation of asbestos, lead paint, galvanizing materials, contaminated soils or disposing of process fluids.
- The construction schedule and productivity assume normal weather conditions for the site location. No allowance has been made for dramatic weather events.

-
- There are no lay down areas outside the Project Site's permanent fence line other than the temporary use of an area between the northern fence line and Adohr Rd.
 - Raw Water quality from the BVWSD has been assumed to be per the Project's Design Basis. The water quality will need to be confirmed by bench scale testing during a subsequent phase of engineering to confirm that the Water Treatment Plant design is appropriate.
 - WTP design does not consider formic acid contamination in the waste streams.
 - An allowance has been included to address the application of visual enhancement measures (landscaping or other) that are likely to be imposed by the California Energy Commission (CEC) to mitigate negative visual impacts at key receptor location(s). This allowance may or may not be sufficient and will need to be revisited upon receipt of the Final Staff Assessment (FSA) conditions of certification.
 - The estimate includes allowances for noise mitigation walls around the large compressors, but no additional provisions have been included to provide for noise attenuation at Key Receptor locations. The need for additional noise mitigation measures will be studied during the subsequent phase of engineering and after CEC conditions of certification has been received.
 - The Air Separation Unit (ASU) that will be constructed within the Project Site's fence line as a Design Build Own Operate (DBOO) unit is the responsibility of HECA LLC (Owner). The estimate addresses interface requirements only.
 - The plant design and this estimate are based on a single feedstock composition and blend of 75% coal/25% petcoke (heat input basis) as specified in the Project's Design Basis.
 - The engineering, procurement, construction, and associated rights of way (ROW) for the Project's linears (raw/potable water lines, natural gas line, electrical transmission lines, and the CO2 pipeline) are the responsibility of the Owner and are not included in the estimate.
 - Construction of the new Wheeler Ridge power transmission interconnect station (CAISO) and upgrades/modifications (if required) to the Wasco coal transloading facility are the responsibility of the Owner and are not included in the estimate.
 - Currency conversion rate for Euro was based on an average 1Q2013 rate of 1.31 US dollar per Euro.

- The estimate utilizes Technology Licensor standard designs. No provisions or allowances have been included to accommodate standardization of the various Technology Licensor designs across the project.

D. General Exclusions

- No provisions have been provided in the design, or in the Capital Cost Estimate, for a Thermal Oxidizer Effluent Scrubber (Dynawave or equivalent) per direction received from the Owner during a Dec 5, 2012 meeting.
- No provisions or allowances have been included for an operator shelter with restrooms in the area of the product loading stations. This assumption will be re-evaluated with input from the Owner during the next phase of engineering.
- No provisions have been provided for the demolition/remediation of the former Port Organics facility or the residential property previously owned by Ackerman.
- No allowance has been included for any County road or overpass improvements that may be required by the CEC or the County, or because of heavy haul permit requirements.
- No allowance has been included for CEC support during detail engineering.
- No provisions have been included to address the implementation of Dark Sky measures as there were no measures specified by the County as of March 2013.
- No provisions have been included for mitigation measures that may be imposed by the Kern County Planning and Community Development Departments.
- No provision or allowances have been included for UAN truck loading facilities beyond the single loading facility specified in the Project's Design Basis. This basis will be re-evaluated with input from the Owner during the next phase of engineering.
- No provisions or allowances have been included for linears outside the Project site fence line (Natural Gas, Raw Water, Potable Water, CO₂ for EOR, Electrical Transmission including interconnect fee, rail spur).
- No allowances have been included in the estimate for the CEC's Final Staff Assessment (FSA), or other agency "Conditions of Certification" that may impose changes in plant design and capital cost.
- No provision or allowances have been included for a Rail Car Mover

- No provision or allowances have been included for Road Improvements outside fence line including improvements required for construction and final operation.
- No provision or allowances have been included for Drainage Control /Remediation outside the fence line.
- Emergency Generator and Firewater Pump pricing impacts related to Tier 4 diesel emission requirements are not included in the estimate as supplier pricing was not available to address Tier 4 requirements in 1Q2013.

E. Basis Documentation

The estimate is based on key design documentation developed during the FEED. These included the Project Design Basis, Equipment Lists, Plot Plan(s), PFDs, P&IDs, Licensor and Specialty Contractor design documentation and pricing data (MHI, Linde, Casale, Weatherly, Jacobs, HDR, Sanvik, etc.), and other applicable drawings and related specifications (structural and civil sketches and drawings, electrical one-lines, load list, area classification, heat tracing, instrument index, etc.).

F. Pricing Strategy

The estimate was developed on a reimbursable basis.

3.11.2 Direct Field Costs

A. Construction Execution Strategy

The field construction work has been estimated as union shop construction execution.

Some specialty subcontract work is included in the Direct Field Costs, with all-in labor and Indirects built into the unit rates for the following:

- Concrete testing
- Electrical heat tracing
- Piping x-ray and stress relief
- Surveys & laser mapping

B. Labor Rate Basis

Craft labor posture was based on recommendations developed by Fluor Industrial Relations. A survey of the project location and vicinity was conducted to determine labor posture journeyman wages, craft availability and other pertinent labor trends. Field Labor Rates are

based upon a Project Labor Agreement and Area Labor Market Analysis (ALMA) from December 2012. All in Loaded Composite labor rates are based on crew mixes provided by Fluor Construction and include Fringes, PT&I, subsistence. The estimate project work week is 50 hours plus spot overtime. Craft costs for Small Tools and Miscellaneous are included in the composite labor rate based upon the cost per direct field hour as estimated in the IFC indirect field cost section. Indirect costs for Temporary Facilities, Construction Services, Construction Supervision (Staff) and Miscellaneous are included in IFC indirect field cost section. Wage rate basis is the first quarter of 2013. The rates do not include a safety incentive or forward escalation.

C. Productivity

Fluor Construction estimated craft productivity by reviewing jobsite conditions including weather, project schedule, overtime, and shift work requirements, estimated craft skill level plot saturation/congestion and other factors. Productivity adjustments were provided by Fluor Construction and have been applied to Fluor Estimating Standard Unit Work Hours.

D. Demolition

HECA is a new grassroots facility and it is not anticipated that any demolition will be required.

E. Civil/Concrete

i) Quantity Basis

The Fluor Civil/Structural Engineering department provided the quantities and sketches for the excavation, backfill, concrete, drainage, paving, caissons, fireproofing, and other miscellaneous scopes of work. The trenching, bedding, and backfill quantities for the underground storm water and sanitary sewer are included based on calculations made from the piping quantities provided by Fluor's Civil Engineering department. The trenching, bedding, and backfill quantities for the underground firewater, cooling water and oily water sewer are included based on calculations made from the piping quantities provided by Fluor's Piping Engineering department. The trenching, bedding, and backfill quantities attributed to Electrical/Instrumentation/Control System duct banks are included based on calculations made from the quantities provided by Fluor Electrical Engineering department. The quantities for fireproofing of steel structures were provided by Fluor's Structural Engineering department.

ii) Pricing Basis

The concrete pricing is based on quoted local area costs for ready mix concrete at 4000 psi. The final composite pricing, including re-bar, form work, anchor bolts, accessories, etc, reflect Fluor's concrete composite charts.

The estimate includes quoted costs from a local supplier for imported new granular structural fill material and sand bedding for road bed material.

F. Structural Steel

i) Quantity Basis

The Fluor Structural Engineering department provided sketches and quantities for all structural steel requirements outside of Gasification, Water Treatment and Solids Material Handling. MHI provided structural steel quantities for Gasification, Jacobs Engineering provided quantities for Water Treatment, and Fluor Mechanical for Solids Material Handling. A connection allowance is included for non-detailed requirements (i.e. base plates, gussets, shear plates, etc.) in the quantities provided. Structural steel quantities for vessel ladders and platforms are provided by Fluor Mechanical Engineering department. Structural steel quantities for small piping field supports were provided by Fluor's Piping Engineering department. The quantities for structural steel fireproofing are included in the concrete account.

ii) Pricing Basis

The material pricing for steel members, grating, handrail, stairs, ladders, platforms, safety gates, and fireproofing is based on supplier budgetary pricing. Pricing includes freight to jobsite from split locations due to amount exceed local capacity.

G. Buildings

i) Quantity Basis

The Fluor Architectural department provided sketches and description of building requirements.

ii) Pricing Basis

The square foot pricing is based on in house pricing and quotes received from Klassen, a local building contractor.

H. Mechanical Equipment

i) Quantity Basis

The mechanical equipment estimate is based on the Mechanical Equipment List.

ii) Pricing Basis

The Fluor Mechanical Engineering Group provided pricing for all equipment tag items over \$250k. Pricing is based on formal quotes, budgetary e-mail vendor quotes or in-house pricing. Pricing was provided by Technology Licensors/Providers for their proprietary equipment (Linde, Casale, & Sandvik) and by Specialty Contractor(Jacobs) for Water Treatment Plant equipment. Solids Material Handling, Cooling Towers, and Field Fabricated Tanks pricing was provided by contract bid tabulation. Pricing for Gasification, the Combustion Turbine/Steam Turbine /Generator, and the EOR CO2 Compressor was provided by MHI.

I. Piping

i) Quantity Basis

The piping quantities were generated by the Fluor Piping Engineering and Fluor Estimating departments. These quantities are identified by line number on the P&IDs. The quantities for all other piping, flanges and manual valves were taken off and included in the estimate by Fluor Piping directly from the P&IDs. The Piping department provided line lengths and fittings for additional piping not shown on the P&IDs such as compressor and pump auxiliaries, storm water, firewater, and oily water sewer systems. The estimate is based on shop fabricating all piping except for screwed and non-metallic piping systems. Fluor Estimating included the costs associated with pipe accessories (shoes, guides, hangers, etc.), testing, non-process vents and drains, NDE, stress relief, PMI and hydrotesting up to mechanical completion.

All painting of shop fabricated piping is included in the estimate as shop applied and is included in the piping shop fabrication account. An allowance is included for field touchup painting and for line service labeling.

The insulation and tracing requirements for piping is based on the P&IDs and the estimated piping line quantities.

ii) Pricing Basis

The pricing for pipe material, fittings, and valves are based on historical information compiled by Fluor and evaluated by metallurgy. Each grouping of piping materials (Carbon Steel, Stainless Steel, Chrome, High Alloy and Non-metallic) is evaluated according to a size range. Each pricing item is further evaluated on a material category dollars per pound basis. The pricing for Contra Trace is based upon in-house pricing and includes the necessary supplier engineering.

J. Electrical

i) Quantity Basis

Electrical material quantities were developed by the Fluor Electrical Engineering and Fluor Estimating departments.

The estimate for electrical includes the following:

- Pre-fabricated substation/instrument equipment room PDC/RIE's.
- Transformers, Isophase busduct & circuit breakers, etc.
- Lighting based on the illumination levels specified in the project electrical design criteria. Centrally located lighting panels/transformers supply branch circuits at 208/120V.
- Grounding consisting of buried bare copper conductor with stub-ups to the new process equipment, and with ground rods installed in accordance with the NEC.
- Heat tracing for piping as specified by Piping Engineering in their material take-offs. Vessel Heat tracing was identified on the P&ID's and is limited to three vessels (SWS Feed Drum, Ammonia Stripper Feed Drum, and the Refrigerant Feed Drum).

ii) Pricing Basis

Budgetary quotes for the following engineered items were obtained through formal RFQs:

- Power Distribution Centers and Switchgear
- GSU and UAT Power Transformers
- Substation Power Transformers

Bulk electrical material pricing is based on Fluor internal pricing and historical information.

Allowances for the following items are included in the estimate:

- Testing of the ground system
- Testing of electrical equipment located in PDC/RIE's
- Installation of cathodic protection
- Electric heat tracing is included based on in-house data from recent subcontract quotes
- Internal PDC work such as cables that cross shipping sections, installation of HVAC, Cables from Electrical room to RIE, etc.

K. Control Systems

i) Quantity Basis:

The tagged instrument and control valve counts and descriptions are defined in the instrument index, which is based on the P&IDs. No additional allowance for tagged instruments has been included in the estimate.

Instrument bulk material quantities were developed using Fluor's Control Systems Engineering department's "standard assemblies". Fluor Estimating provided material cost and labor for installation by type of instrument.

ii) Pricing Basis

The tagged instruments, control valves and bulk material pricing are based on vendor budgetary pricing and Fluor historical information.

Analyzers, DCS and Telecommunications systems are based on supplier budgetary quotations.

L. Enterprise Integration and Communication Systems (EICS)

i) Quantity Basis

The Control Systems Group is responsible for the development of all project quantities, as well as the requirements for all required specialty hardware and bulk commodities.

ii) Pricing Basis

The pricing basis is on supplier budgetary pricing and Fluor historical data.

M. Paint / Insulation

i) Quantity Basis

The insulation and painting scopes of work are estimated based on the project design specifications for equipment and pipe. Paint touch-up quantities were generated by the Estimating Group, based on the assumption that all equipment and non-insulated piping would be supplied with primer and finish coating. Touch-up painting labor was calculated based upon crew work over a period of one year.

Piping material take-off quantities identified insulated piping and the mechanical equipment list identified equipment insulation.

ii) Pricing Basis:

Insulation material and touch-up painting have been estimated based on internal pricing and historical information.

N. Scaffolding

The scaffolding labor estimate is included as a percentage of the direct field work hours.

O. Premium Time

The standard field work week has been assumed to be single shift 5-10's. These serve as the basis for the overtime premium calculation.

P. Craft Per Diem

Craft per diem is included in the wage rate as per union agreements.

3.11.3 Construction Indirect Field Costs

Fluor Construction provided assistance and oversight in the development of the indirect field costs (IFC) estimate. The IFC includes:

- Safety Watch which has been estimated as a percentage of the direct field labor hours.
- Temporary facilities which include Field Staff offices as rented trailers with additional cost for mobilization/demobilization. Space requirements include work space, circulation space, meeting space and drawings/file storage. Toilet facilities are rented port-a-johns and toilet trailers. Shop facilities, brass alleys, guard/gate house,

temporary warehouse, change houses, weather protection, wind breaks, and shelters are also included.

- Construction Services which includes general clean up, final clean up, office janitors, dumpster service, tool room attendant, 24 hour site security, safety equipment and safety supplies. Chemical screening for all staff/craft and 10% random. Onsite bussing and fire retardant clothing are included.
- Field Office Supplies and expense are included on dollars per staff hour basis. Computers are included for required staff positions. Estimated costs for purchased equipment including necessary LAN/WAN hardware, connections and accessories and required software. Field office furnishings with work stations, file equipment, stick files, conference tables, chairs, misc. office equipment, calculators, coffee pots and on-site reprographics are included. Time and attendance recording system and Field payroll charges are included. Communications (Telephones, Radios, Postage and hookup) cost are included. No allowance for post construction salvage is included.
- Field Staff was derived from a detailed staffing plan. Its estimated cost includes the required travel and subsistence. Support costs for HR/IR, QC and Safety audits and Home Office Construction management presence during engineering are also included, as well as constructability reviews, rigging, and IS support.
- Craft benefits and burdens are included in the jobsite wage rate.
- Construction Equipment, tools and consumables are estimated on a dollar per labor hour basis.
- Heavy Haul/Lift Estimate includes all freight, mobilization, demobilization, fuel, servicing, and maintenance and is based upon a supplier quote.
- Small tools & consumables are included in the jobsite wage rate.
- Construction permits, licenses, bonds.

3.11.4 Home Office Costs

The individual discipline groups provided the home office work hours estimate for this project. The engineering hours are based on the Project Execution Plan (PEP) and EPC Execution schedule. Project support hours are based on the estimated staffing required to support engineering, development of project deliverables, and historical data from similar scale projects.

Fluor's Project Controls department led the effort to prepare the home office labor costs based on forecast first quarter 2013 base compensation rates with payroll burdens, benefits, and expenses included based on the project's commercial terms.

Typical costs include:

- Engineering and design disciplines including Process Engineering
- Project management, procurement, contract management and other project support
- Travel, business expenses, relocation/policy costs, consultants, subcontracts, third party / licensor support
- Overhead and contingencies

3.11.5 Freight

Domestic Freight for Heavy Haul Equipment and Heavy Haul Bulk Materials were developed by Fluor's Logistics department for each major items or group of items utilizing specific cost estimates with assistance from a major cargo company. Ocean freight costs for equipment items that are being purchased out of country were also developed by Fluor's Logistics department using input from ocean freight carriers. Freight costs for the remainder of the equipment and bulk materials were based on site specific historical data.

3.11.6 Taxes

California sales tax has been included for materials based upon the Kern County rate.

3.11.7 Spare Parts

The following spare parts are included in the estimate:

- Startup spares are included in the Commissioning Estimate
- Capital spares are included as identified by Fluor's Mechanical Engineering group
- An allowance for operating spares for two years are included as identified by Fluor's Mechanical Engineering group

3.11.8 Vendor Representatives and Consultants

The cost for vendor representatives is based on an allowance of a percentage of the material.

3.11.9 Commissioning & Start-Up Support

The commissioning and start-up support estimate was prepared by Fluor's Commissioning Specialists group.

A. Home Office Execution

The Home Office Commissioning Support estimate provides commissioning team support for pre-mobilization planning and document development efforts. The major deliverables of the phase are:

- Electrical System Commissioning and Energization Plans
- Control System Commissioning Plans
- Instrumentation Loop Check Plans
- Mechanical System Commissioning Plans
- Lube Oil Flushing Plans
- Piping System Pre-Operational Cleaning Plans
- Process System Initial Operation Plans
- Preventative Maintenance Manual
- Engineering and Design Review support
- Hazop and Startup Reviews
- Mechanical Completions Software database setup
- O&M Training Program

An estimate of required travel and subsistence has also been included.

B. Field Execution

The Field Commissioning estimate provides detailed commissioning team staffing plan in support the plant pre-commissioning, initial operations, startup and performance testing periods.

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- Field Office Supplies and Expenses include Commissioning Staff offices as rented trailers with additional cost for mobilization/demobilization. Computer and software support is included on a dollar per staff hour basis. Field office furnishings with work stations, file equipment, stick files, conference tables, chairs, misc. office equipment, calculators, coffee pots and on-site reprographics are included. No allowance for salvage is included.
 - Equipment and Supplies includes a small tool allowance based on a dollar per craft man hour basis.
 - Testing and Services include estimates for the following subcontracted activities. The allowances included for these planned subcontracted activities are based on historical data from similar projects:
 - Specialty Instrumentation craft support
 - High pressure pipe cleaning (Hydrolazing)
 - Steam Turbine Lube Oil flushing
 - Gas Turbine Lube Oil flushing
 - Hydraulic Oil flushing
 - Detergent flushing of the HRSG
 - Nitrogen blows for cleaning of the Natural Gas lines within the plant boundary
 - Transformer oil testing services
 - Water testing services
 - Spent Caustic processing (from cleaning during commissioning)
 - Chemicals, Fuels and Lubricants include estimates for the first fill and consumption of process chemicals through project Substantial Completion. First Fill quantities and consumption is based on engineering analysis. Chemical unit pricing is based on recent supplier quotations. An allowance for miscellaneous consumable chemicals and diesel fuel is included.
 - Site Staff was derived from a project specific detailed staffing plan and includes required travel and subsistence. Process Engineering site staffing is provided for Unit startup and testing support.
 - Craft Support requirements were developed from a detailed staffing plan. A composite wage rate was applied to the craft hours to estimate total commissioning craft support costs.
 - Technology Licensor and equipment supplier and Technical Assistants (T/As) support allowances are included based upon the project schedule and Licensor input.

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- A cost allowance for an O&M Training program has been included.

3.11.10 Escalation

The FEED estimate has been prepared on an overnight first quarter 2013 pricing basis.

3.11.11 Contingencies

Contingency is defined as “a special monetary provision in the project budget to cover uncertainties or unforeseeable elements of time/cost within the scope of the project under Fluor's control. Contingency typically covers risk of cost increases resulting from lack of scope definition, lack of particular experience, omissions, underestimation, technical problems, nonspecific schedule slippage, and like items. Scope changes are specifically excluded from contingency, and considered an Owner cost.”

3.11.12 Owner's Costs & Responsibilities

Owner's costs (HECA LLC) have been excluded from the estimate. Some of the items considered to be part of owner's costs are as follows, but not limited to:

- All project financing, project development costs or fees, land and land development costs, mineral rights and leases, and right-of-ways and easements associated with the Project.
- Land cost
- All property taxes on permanent plant equipment/materials.
- All-Risk Insurance
- Business management systems
- Owner's staff and expenses
- Owner's Consultants
- Marine cargo insurance
- Owner's auditing/inspection/witness testing
- Owner's contingency
- Owner's escalation
- All cost and schedule relief for underground obstructions; identification, removal and remediation of existing hazardous waste materials; consultants (biologists,

paleontologists, cultural resource specialists, etc.), as required by the government, for any purpose.

- All non-construction related permits (Air, Land Use, Environmental, Water Supply, Waste Water, Disturbance of Natural Resources, Site Assessment, Industry Approvals, Electrical Transmission), and associated studies, reports and fees. This also includes all permits required for Commissioning and Operation of the Facility and permits in Owner's name.
- Any special fees or permits required for electric utility interconnects.
- Occupancy permits; fire and safety approvals/permits.
- Backfeed power and all fuel (coal, petcoke, and natural gas), limestone, and other related consumables required during commissioning and testing.
- The cost of mitigation measures and community improvements that may be imposed by Kern County Planning and Community Development Departments and other agencies.
- Plant operations/maintenance vehicles (ambulances, fire, switch engine, etc.)
- Plant security after substantial completion
- Operating Spares for plant operation.
- Vendor representatives requested by the Owner during warranty period and after.
- All interior furnishings and furniture, shop tools, shop machinery, operation and maintenance rolling stock and operational and maintenance staff.
- Natural gas fuel pipeline from its offsite source(s) to the power plant fence line. A flanged connection will be the interface point. The Owner is responsible for having the off-site natural gas pipeline pigged and cleaned.
- Supply of lubricants and chemicals beyond Substantial Completion.
- Outside the Project site fence line infrastructure upgrades and EPC of site interface linears.

3.11.13 Fee

EPC contractor fee has been included.

3.11.14 Warranty Reserve

Warranty Reserve has been included.

3.11.15 Late Changes

These scope items were identified and defined after the estimate deliverables “deadline” and have been estimated as Rough Order of Magnitude (ROM) costs using a variety of estimating methods, including allowances.

3.11.16 Capital Cost

The capital cost for the HECA Project as described in the preceding Basis of Estimate is estimated at \$4,933,000,000 USD on an overnight first quarter 2013 pricing basis. As previously described, the estimate excludes forward escalation and any Owner’s costs. The capital cost estimate when allocated into the four (4) major functional areas described in Section 3.11.1 is as follows:

1) Hydrogen-Rich Fuel Production	\$1,850,000,000
2) Power Production	\$733,000,000
3) Fertilizer Manufacturing Complex	\$723,000,000
4) Common Facilities	\$1,627,000,000
Estimate of Total Installed Cost (TIC)	\$4,933,000,000

Although the breakdown provides an indication of the relative relationship in capital cost between the functional areas, it is strongly recommended that the estimate be viewed on an overall TIC basis and in conjunction with the Basis of Estimate. It is noted that the allocation into the four major functional areas does not represent an estimate of TIC for an individual functional area. This is because the functional area allocations incorporate a pro rata allocation of all capital cost components beyond those defined within the preceding Basis of Estimate as Direct Field Costs (Section 3.11.2). If standalone TIC estimates were to be developed for the individual areas they would likely not align with these pro rata based allocations. Furthermore, the standalones would also need to incorporate out of the “Common Facilities” their supporting Utility & Offsites requirements. For these reasons it is strongly emphasized that the estimate be looked at from the standpoint that it represents an estimated capital cost for the overall HECA Project on a first quarter 2013 pricing basis.

3.11.17 Estimate Disclaimer

This Capital Cost Estimate was prepared for Hydrogen Energy California LLC "HECA" by Fluor Enterprises Inc. and other independent consultants and is based in part on information not within the control of either Fluor or the consultants. Neither Fluor nor the consultants have made an analysis, verified, or rendered an independent judgment of the validity of the information provided by others. While it is believed that the information contained herein will be reliable under the conditions and subject to the limitations set forth herein, neither Fluor nor the consultants guarantee the accuracy thereof. Use of this report or any information contained therein shall constitute a release and agreement to defend and indemnify Fluor and such consultants from and against any liability (including but not limited to liability for special, indirect or consequential damages) in connection with such use. Such release from and indemnification against liability shall apply in contract, tort (including *negligence* of Fluor or those consultants, whether active, passive, joint or concurrent), strict liability, or other theory of legal liability; provided, however, such release, limitation and indemnity provisions shall be effective to, and only to, the maximum extent, scope or amount allowable by law."

Notwithstanding the above, neither the Capital Cost Estimate nor any information contained therein or otherwise supplied by Fluor in connection with the FEED and this Report shall be released by Company or used in connection with any proxy, proxy statement, proxy soliciting materials, prospectus, Securities Registration Statement or similar document without the express written consent of Fluor, except as may be required by law.

3.12 OPERATIONS AND MAINTENANCE COST ESTIMATE & BASIS

The Operations and Maintenance (O&M) Basis of Estimate that follows describes how the Annualized O&M Cost Estimate that is included herein was prepared for the HECA Project during FEED.

3.12.1 General

The HECA Project's O&M estimate was prepared on an "Annualized" basis for a 25 year period. All labor, equipment, and material cost are estimated as of the First Quarter 2013. All labor and material is estimated to be performed on a reimbursable cost basis. No provisions are included for escalation beyond the first quarter of 2013. Estimating Contingency and Risk Event Contingency have not been included per Owner's (HECA LLC's) request.

The O&M Cost Estimate reflects projections arrived at during FFEED and is based on various assumptions including the plant configuration as conceived at the end of FEED, anticipated plant operating requirements, and experience combined with historical data. Actual values are expected to be different from what is presented.

3.12.2 Scope of Estimate

The O&M Cost Estimate was prepared in accordance with the deliverables developed during FEED. The scope of the O&M estimate begins at Substantial Completion. The O&M Cost Estimate is comprised of the following components:

- 1) O&M Labor (open shop – non union)
- 2) Outage Labor (closed shop – union, and non union outage management)
- 3) Administration (non labor office cost – computers, supplies, IT infrastructure, phones, etc) and 3rd Party Labor (facility security, janitorial, and specialty contractors)
- 4) Materials (operational spares, leased equipment, consumables, and rotating equipment maintenance)
- 5) Catalysts and Chemicals
- 6) Waste disposal, including transportation

3.12.3 General Assumptions, Qualifications, and Exclusions

The general assumptions, qualifications, and exclusions associated with the preparation of this Estimate are listed below:

-
- The O&M estimate has been developed for a 25 year plant life
 - The estimate begins at Substantial Completion. O&M support during Commissioning & Startup is not included
 - All O&M labor and material is estimated to be performed on a reimbursable cost basis
 - All labor cost for the facility is estimated for staff, O&M craft (open shop), and Outage Labor (union) based on existing prevailing wage rates
 - Labor posture for the O&M provider is open shop
 - Labor posture for outage/major maintenance work is utilizing Building Trades Union Labor
 - Plant is to be maintained to achieve the targeted plant availability in mature operations
 - Plant will ramp daily but will not cycle on and off regularly
 - Power Block and the Gasification Island have a 12 month outage cycle
 - Owner will maintain a Long Term Service Agreement (LTSA) with Combustion Turbine supplier; the cost of this LTSA is outside the scope of this O&M estimate
 - Fertilizer Complex, Gas Treating, EOR CO₂ Compression, and pollution control equipment have a 36 month outage cycle with the added capability to perform maintenance work during the annual outage
 - Feedstock delivery is scheduled as to not overlap or bottleneck the plant operation
 - Product export is scheduled such that it will not impact the operation of feedstock deliveries
 - All labor, maintenance equipment, spare parts, etc. costs have been estimated as of the first quarter 2013
 - Forward escalation and “Late Change” or post FEED plant design/scope changes are excluded from the estimate
 - Maintenance costs for facilities and infrastructure to support future increases in plant capacity are not included
 - No cost of cash is included in the estimate
 - California Sales Tax has been included at the Kern County rate on the annualized average of: 1) the estimated catalysts and chemicals costs; and 2) the estimated non-labor portion of material costs"
 - Customs & Import Duties are not included in spare parts costs
 - No provisions have been included for changes in Federal or State laws and regulations

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- No provisions have been included for standardization and/or interchangeability of spare parts for instrumentation, motor drivers or other equipment to reduce spare parts inventory and associated cost. It is anticipated that this activity will be performed during the EPC phase of the project
 - No allowance has been made for unplanned environmental events
 - No allowance has been included for all risk liability insurance
 - No allowance has been made for environmental fees
 - O&M costs for the Air Separation Unit are not included
 - Transmission Lines associated with power generation will be maintained to the transfer point with PG&E
 - Rail loop and spur will be maintained to the existing Buttonwillow branch line of the SJV rail road
 - Rail car maintenance is not included
 - Feedstock (coal and petcoke) and Fluxant purchase and delivery are not included
 - Raw water purchase and delivery are not included
 - Chemical usage for the Water Treatment is based on raw water quality with a TDS of 2000
 - An estimate of the costs associated with transporting spent caustic to a re-use / recycle facility within a 120 mile radius has been included
 - Fertilizer Product (Urea Pastilles and UAN-32 Solution), Degassed Elemental Sulfur, and Gasifier Solids Product transportation costs are not included
 - An estimate of the landfill and transportation costs associated with disposal of process wastes (ZLD solids, etc.) and general trash within a 40 mile radius has been included
 - No allowances have been included in the estimate for the CEC's Final Staff Assessment (FSA), or other agency "conditions of certification" that may impose changes in plant design and O&M cost

A. Offsite Facilities Exclusions

Operations and maintenance associated with the following Offsite Facilities (outside Project Site "fence line"), are excluded from the estimate:

- Natural Gas Line outside Project Site "fence line" including revenue meter
- CO2 Pipeline Line outside Project Site "fence line" up to the custody transfer point

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- Potable Water Line outside Project Site “fence line” including metering facility
 - Raw Water Line outside Project Site “fence line” including metering facility
 - Roads outside Project Site “fence line”
 - Transmission System Upgrades
 - Air Separation Unit
 - Wasco, CA Feedstock Trans-loading Facility

B. Equipment Maintenance

The following types of equipment will be maintained based on established maintenance intervals with one year equivalent to 8,000 hours.

- Pumps
- Compressors
- Motors
- Gearboxes
- Fans
- Switchgear
- Crushers
- Material Handling
- Tanks
- Diesel Engines

3.12.4 Basis Documentation

The estimate is based on key design documentation developed during the FEED. These included the Project Design Basis, Equipment Lists, Plot Plan(s), PFDs, P&IDs, Licensor and Specialty Contractor design documentation (MHI, Linde, Casale, Weatherly, Jacobs, HDR, Sanvik, etc.), and other applicable drawings and related specifications.

3.12.5 Operations and Maintenance Team

The goal of the Operations & Maintenance Team will be to employ best practices to minimize unscheduled shutdowns. A policy of predictive maintenance will be applied for all critical

equipment. Maintenance activity estimates are based on HECA's intent to utilize contractors for the performance of all planned and unplanned tasks.

3.12.6 Operational Activity Methodology

The operational portion of the estimate covers the cost for normal day-to-day operations of the plant on a 24 hr/day x 7 day/wk x 365 day/yr basis, including managing the plant operations and normal interfaces with off-takes and vendors.

Workweek Basis:

- Exempt Staff basis is 40 hours/week
- Non Exempt Maintenance Staff basis is 44 hours/week
- Non Exempt Operations Staff is man to man coverage (absences are covered via overtime)
- Outage Labor basis is 60 hours/week (6 x 10hr/day schedule)

A. Catalyst, Chemicals and Major Consumables

An estimate of average annual costs is included in this estimate.

B. Operations Equipment

An estimate of operations tools and equipment to be leased or purchased is based on base crew size. Most operations equipment utilized in the plant is expected to be leased.

C. Routine Maintenance

An estimate of the Day-to-Day Routine Maintenance Labor has been determined by identifying the routine preventative and predictive tasks and the associated crew mix to accomplish these activities. Recent and ongoing projects were utilized in establishing the appropriate crew sizes for these estimates. Daily maintenance crews will support operations and complete preventive and predictive maintenance tasks.

D. Outage (Turnaround)

Outages will be supported with Building Trades Union Labor under the National Maintenance Agreement (NMA) as required.

E. Maintenance Equipment and Tools

An estimate of maintenance tools and equipment to be leased or purchased was arrived at based on crew size. The purchase value and lease rates for maintenance equipment and tools were estimated utilizing in-house historical data from recent projects. Most maintenance equipment utilized in the plant is expected to be leased.

3.12.7 Spare Parts

As a basis for arriving at the spare parts estimate, the following Spare Parts Categories and Definitions were used:

A. Start-up and Commissioning Spares

Start-up and commissioning spares are classified as a Capital Expense and thus, **are not included** in the O&M Estimate. These are spares required for the timely and successful commissioning of the facility. Start-up & Commissioning Spares are parts or assemblies, which could be subject to damage, breakage or deterioration during shipment, commissioning, start-up and the initial run-in period. These spares will be procured at the same time as the equipment to which they relate.

B. Capital Spares

Also known as Insurance or Mandatory Spares, capital spares are classified as a Capital Expense and thus, **are not included** in the O&M Estimate. These spares are parts, assemblies or complete warehouse units that are purchased with the original equipment to which they relate because of high cost factors, engineering, fabrication, testing and fitting requirements or long-lead times. These spares are usually associated with major equipment and are required to be held in stock to achieve the required plant availability.

C. Operation Spares

Operation spares are classified as an O&M expense and **have been included** in the O&M estimate. These spares are parts and assemblies normally consumed on the basis of scheduled maintenance, overhauls, or as result of inspections (wear, corrosion, erosion, deterioration) during normal service. They are required to maintain equipment in satisfactory working order post commissioning and into the operational phase. The initial operating spares could be procured at the same time as the equipment to which they relate.

3.12.8 Contingency

Contingency is defined as “a special monetary provision in the project budget to cover uncertainties or unforeseeable elements of time/cost within the scope of the project under Fluor's control. Contingency typically covers risk of cost increases resulting from lack of scope definition, lack of particular experience, omissions, underestimation, technical problems, nonspecific schedule slippage, and like items. Scope changes are specifically excluded from contingency, and considered an Owner cost.”

Per Owner's (HECA LLC's) direction, contingency has not been included in this O&M Cost Estimate.

3.12.9 Owner's Costs

Owner's costs have been excluded from the O&M estimate. Some of the items considered to be part of owner's costs are as follows, but not limited to:

- All-Risk Insurance
- Owner's staff and expenses
- Owner consultants
- Technology Licensor fees during operation
- Combustion Turbine Long Term Service Agreement (LTSA)
- Import duties and surcharge
- Estimating Contingency and Risk Event Contingency
- All property taxes on permanent plant equipment/materials.
- Business management systems
- Forward escalation
- ASU and the O&M of all Offsite Facilities (outside Project Site “fence line”) - pipelines (water, gas, CO₂), transmission lines beyond transfer point with PG&E, roads and bridges/over-passes, Wasco Feedstock Trans-loading Facility, etc
- Marine cargo insurance

- Owner’s auditing/inspection/witness testing
- Annual emissions and other fees (Kern County Business Licenses, FCC Licenses, etc)
- Logistics (Air, sea, and land transportation of Owner’s personnel; company freight; and company catering at site)

3.12.10 O&M Estimate

The O&M cost for the HECA Project as described in the preceding Basis of Estimate is estimated at \$88,400,000 USD on an Annualized Average basis. As previously described, the estimate is on an overnight first quarter 2013 pricing basis and excludes forward escalation and any Owner’s costs. The annualized O&M Cost Estimate when allocated into the six (6) major cost components described in Section 3.12.2 is as follows:

1) O&M Labor	\$27,600,000
2) Outage Labor	\$11,000,000
3) Administration & 3 rd Party Labor	\$4,900,000
4) Materials	\$17,900,000
5) Catalyst & Chemicals	\$18,300,000
6) Waste Disposal & Transportation	\$8,700,000
Estimate of Total Annualized O&M Cost (25-year Plant Life)	\$88,400,000

Although the breakdown provides an indication of the relative relationship in O&M costs between the major cost components, it is strongly recommended that the estimate be viewed on a Total Annualized O&M Cost basis and in conjunction with the Basis of Estimate.

3.12.11 Estimate Disclaimer

This Operations and Maintenance Estimate was prepared for Hydrogen Energy California LLC ("HECA") by Fluor Enterprises Inc. ("Fluor") and other independent consultants and is based in part on information not within the control of either Fluor or the consultants. Neither Fluor nor the consultants have made an analysis, verified, or rendered an independent judgment of the validity of the information provided by others. While it is believed that the information contained herein will be reliable under the conditions and subject to the limitations set forth herein, neither Fluor nor the consultants guarantee the accuracy thereof. Use of this report or any information contained therein shall constitute a release and agreement to defend and indemnify Fluor and such consultants from and against any liability (including but not limited to

liability for special, indirect or consequential damages) in connection with such use. Such release from and indemnification against liability shall apply in contract, tort (including negligence of Fluor or those consultants, whether active, passive, joint or concurrent), strict liability, or other theory of legal liability; provided, however, such release, limitation and indemnity provisions shall be effective to, and only to, the maximum extent, scope or amount allowable by law.

Notwithstanding the above, neither the Operations and Maintenance Estimate nor any information contained therein or otherwise supplied by Fluor in connection with the FEED and this Report shall be released by Company or used in connection with any proxy, proxy statement, proxy soliciting materials, prospectus, Securities Registration Statement or similar document without the express written consent of Fluor, except as may be required by law.

3.13 GENERAL

Additional design-related information for the HECA Project is provided in this section:

- Supplemental Site Plans
- Buildings
- Integrated Control and Safety System (ICSS)
- Noise Evaluation
- Geotechnical
- Railroad Infrastructure

3.13.1 Supplemental Site Plans

The following site plan drawings were developed during FEED as part of the Application for Certification (AFC) prepared and submitted to the California Energy Commission (CEC). These site plans have been identified as “Preliminary” as they were developed early in FEED and utilize an early version of the Overall Plot Plan as a background. The end of FEED Overall Plot Plan is provided in Section 3.9:

- Preliminary Emissions Sources Plot Plan
- Preliminary Grading Plan
- Preliminary Storm Water Drainage Plan
- Preliminary Paving Plan
- Preliminary Temporary Construction Facilities Plan

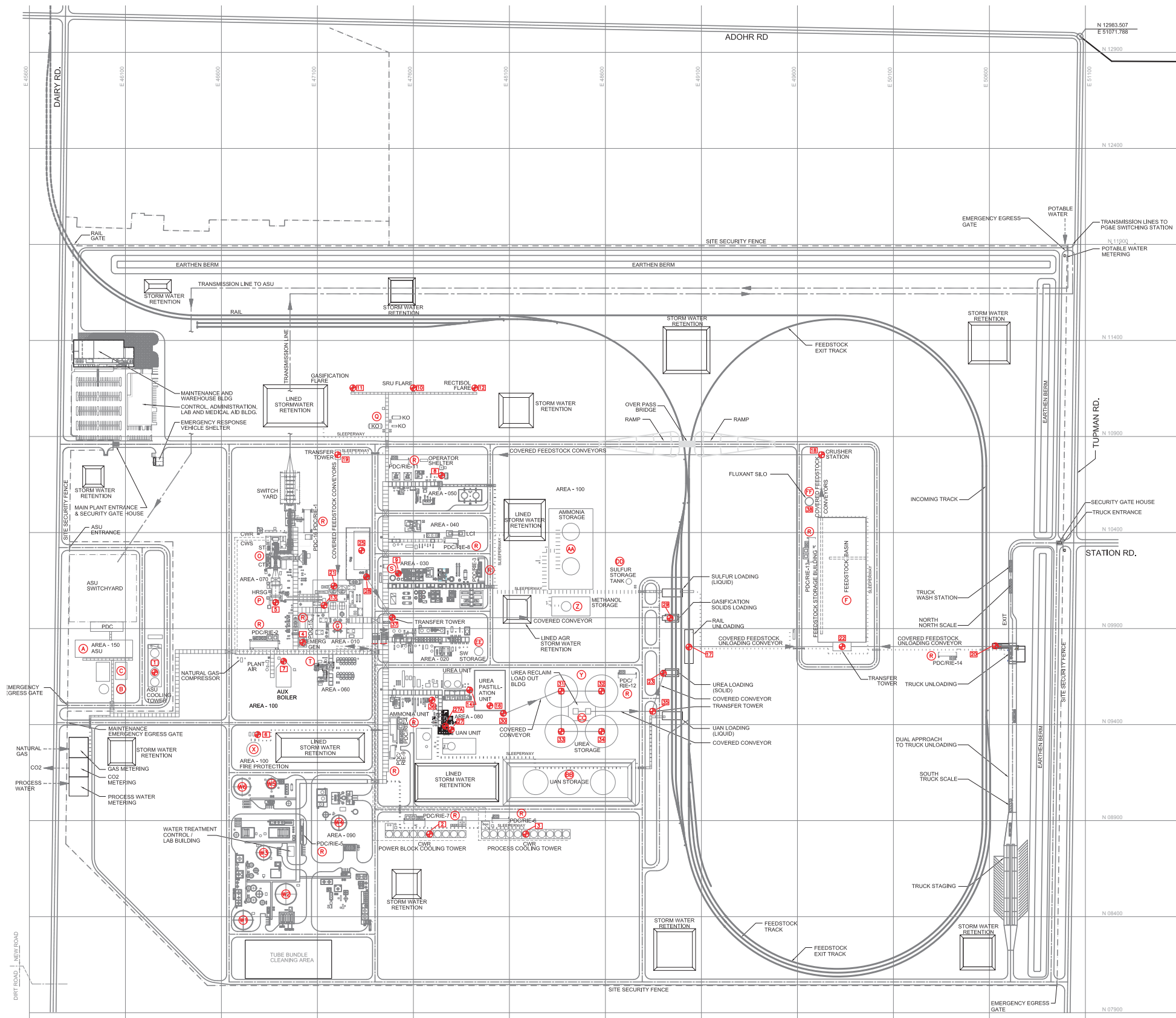
The location of the Project’s emissions sources are identified on the Preliminary Emissions Sources Plot Plan (drawing number 000-50-SK-0002) provided as Figure 3-9.

The Project’s grading concept and the estimated excavation and import earthwork volumes are shown on the Preliminary Grading Plan (drawing number 000-10-SK-0001) as Figure 3-10.

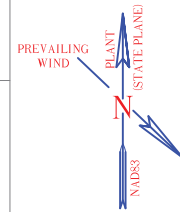
The storm water grading concept and the location of storm water retention basins is shown on the Preliminary Storm Water Drainage Plan (drawing number 000-10-SK-0002) provided as Figure 3-11.

The Project’s paving plan identifying roads and the types of surface treatments for the process and offsite units are shown on the Preliminary Paving Plan (drawing number 000-10-SK-0003) shows the proposed paving at the Project Site and is provided as Figure 3-12.

Temporary construction laydown areas, parking, and offices are identified on the Preliminary Temporary Construction Facilities Plan (drawing number 000-10-SK-0004) provided as Figure 3-13.



DWA #20001: (CALCULATED)	NORTHING	EASTING
STATE PLANE COORD.	2312983,507	6151071,788
NAD83 ZONE V (U.S. FEET)		
LATITUDE: 35°20'25.11201"	LONGITUDE: 119°22'36.22853"	
LATITUDE: 35.340308891°	LONGITUDE: 119.376730147°	



- PLANT COORDINATE AND DATUM NOTES
1. PLANT COORDINATES IN FEET EQUATE TO E. 61XXXXX AND N. 23XXXXXX OF CALIFORNIA STATE PLANE COORDINATE SYSTEM (NAD 83 ZONE V).
 2. PLANT ELEVATION 100.00' EQUATES TO 288.50' ABOVE MSL. (NAVD88).
 3. ACCURACY/TOLERANCE OF EMISSION POINT(S) COORDINATES ARE WITHIN A 50 FOOT RADIUS OF SOURCE POINT NOTED.
 4. LOCATION OF EMISSION POINTS IS SUBJECT TO COMPLETION OF DETAILED DESIGN BY LICENSORS AND EQUIPMENT SUPPLIERS.
 5. EMISSION POINT IS SHOWN FOR INFORMATION ONLY. ZERO EMISSIONS ARE EXPECTED DURING STEADY STATE OPERATION.

ID	SOURCE	STATE PLANE COORD. (EASTING)	STATE PLANE COORD. (NORTHING)	APPROX. ELEVATION (FEET)
1	ASU COOLING TOWER	46253'-0"	9672'-0"	55'
2	POWER BLOCK COOLING TOWER	47684'-7"	8830'-0"	65'
3	PROCESS COOLING TOWER	48185'-6"	8830'-0"	65'
4	EMERGENCY ENGINES (GENERATORS)	47023'-6"	9828'-4"	20'
5	HRSG STACK	46882'-6"	10036'-0"	213'
6	EMERGENCY ENGINE (FIRE WATER PUMP)	46789'-0"	9348'-0"	20'
7	AUXILIARY BOILER (NOTE 5)	46924'-0"	9730'-0"	80'
8	TAIL GAS THERMAL OXIDIZER	47748'-4"	10697'-0"	165'
9	CO2 VENT (NOTE 5)	47521'-6"	10187'-4"	355'
10	SRU FLARE	47599'-8"	11153'-2"	250'
11	GASIFICATION FLARE	47284'-8"	11153'-2"	250'
12	RECTISOL FLARE	47919'-9"	11153'-2"	250'
13	FEEDSTOCK DRYER	47134'-10"	10021'-5"	305'
14	UREA PLANT ABSORBER	47893'-0"	9580'-0"	170'
15	UREA PASTILLATION VENT	47998'-6"	9498'-2"	50'
16	FEEDSTOCK RAIL UNLOADING VENT	49035'-0"	9804'-0"	30'
17	FEEDSTOCK CRUSHER VENT	49726'-0"	10805'-0"	100'
18	FEEDSTOCK TRANSFER TOWER 2	47206'-0"	10805'-0"	100'
19	FEEDSTOCK TRUCK UNLOADING VENT	50631'-0"	9810'-0"	60'
20	GASIFIER FEED BUILDING VENT	47186'-0"	10122'-0"	230'
21	FEEDSTOCK TRANSFER TOWER 1	49833'-0"	9806'-0"	100'
22	UREA LOADING VENT	48902'-0"	9667'-0"	110'
23	GASIFICATION SOLIDS PAD	47330'-0"	10306'-4"	N/A
24	NITRIC ACID ABSORBER VENT	47797'-0"	9373'-0"	120'
25	AMMONIUM NITRATE SCRUBBER VENT	47767'-0"	9392'-0"	55'
26	GASIFICATION SOLIDS BUCKET ELEVATOR	47355'-6"	10169'-2"	30'
27	GASIFICATION SOLIDS LOADING VENT	48936'-10"	9954'-9"	110'
28	UREA BUCKET ELEVATOR	48068'-5"	9458'-8"	50'
29	UREA TRANSFER TOWER 1	48370'-0"	9574'-0"	100'
30	UREA TRANSFER TOWER 2	48580'-0"	9574'-0"	100'
31	UREA TRANSFER TOWER 3	48370'-0"	9364'-0"	100'
32	UREA TRANSFER TOWER 4	48580'-0"	9364'-0"	100'
33	UREA TRANSFER TOWER 5	48846'-3"	9469'-0"	100'
34	AMMONIA UNIT STARTUP HEATER	47697'-0"	9527'-7"	80'
35	GASIFICATION SOLIDS TRANSFER TOWER	47490'-0"	9957'-0"	75'
36	FLUXANT SILO VENT	49661'-8"	10561'-4"	90'

ID	DESCRIPTION	APPROX. ELEVATION (FEET)
A	ASU MAIN AIR COMPRESSOR ENCLOSURE	40'
B	LIQUID OXYGEN STORAGE (LOX) TANK	90'
C	AIR SEPARATION COLUMN CAN	200'
D	FEEDSTOCK BARN	160'
E	GASIFICATION STRUCTURE	260'
F	COMBUSTION TURBINE GENERATOR STRUCTURE	50'
G	HEAT RECOVERY STEAM GENERATOR STRUCTURE	90'
H	FLARE K.O. DRUMS (QTY 3)	40'
I	POWER DISTRIBUTION CENTERS	25'
J	AGR METHANOL WASH COLUMN	330'
K	PSA OFFGAS COMPRESSOR	35'
L	RAW WATER TANK	95'DIA X 70'H
M	TREATED WATER TANK	105'DIA X 65'H
N	FILTERED WATER TANK	75'DIA X 55'H
O	WASTE WATER ZLD FEED TANK	80'DIA X 50'H
P	UTILITY WATER TANK	50'DIA X 55'H
Q	DEMINERALIZED WATER STORAGE TANK	80'DIA X 65'H
R	FIREWATER STORAGE TANK	74'DIA X 50'H
S	UREA STORAGE (4 DOMES)	170'DIA X 85'H
T	METHANOL STORAGE TANK	46'DIA X 55'H
U	AMMONIA STORAGE (2 TANKS)	90'DIA X 70'H
V	UAN STORAGE (3 TANKS)	130'DIA X 65'H
W	UREA RECLAIM LOADOUT BUILDING	30'
X	SULFUR STORAGE TANK	30'DIA X 28'H
Y	SOUR WATER STORAGE TANK	45'DIA X 50'H
Z	FLUXANT SILO	30'DIA X 80'H



Final Topical Report
DE-FE0000663

B.01 – Final Scientific & Technical Report

Fluor Source Documents:

- A4UV-000-50-SK-0002 (Rev G, 4/16/13)
- Amended AFC (08-AFC-8) Project Refinements Revised Fig. 2-47 (Oct 2013)



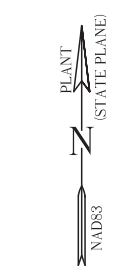
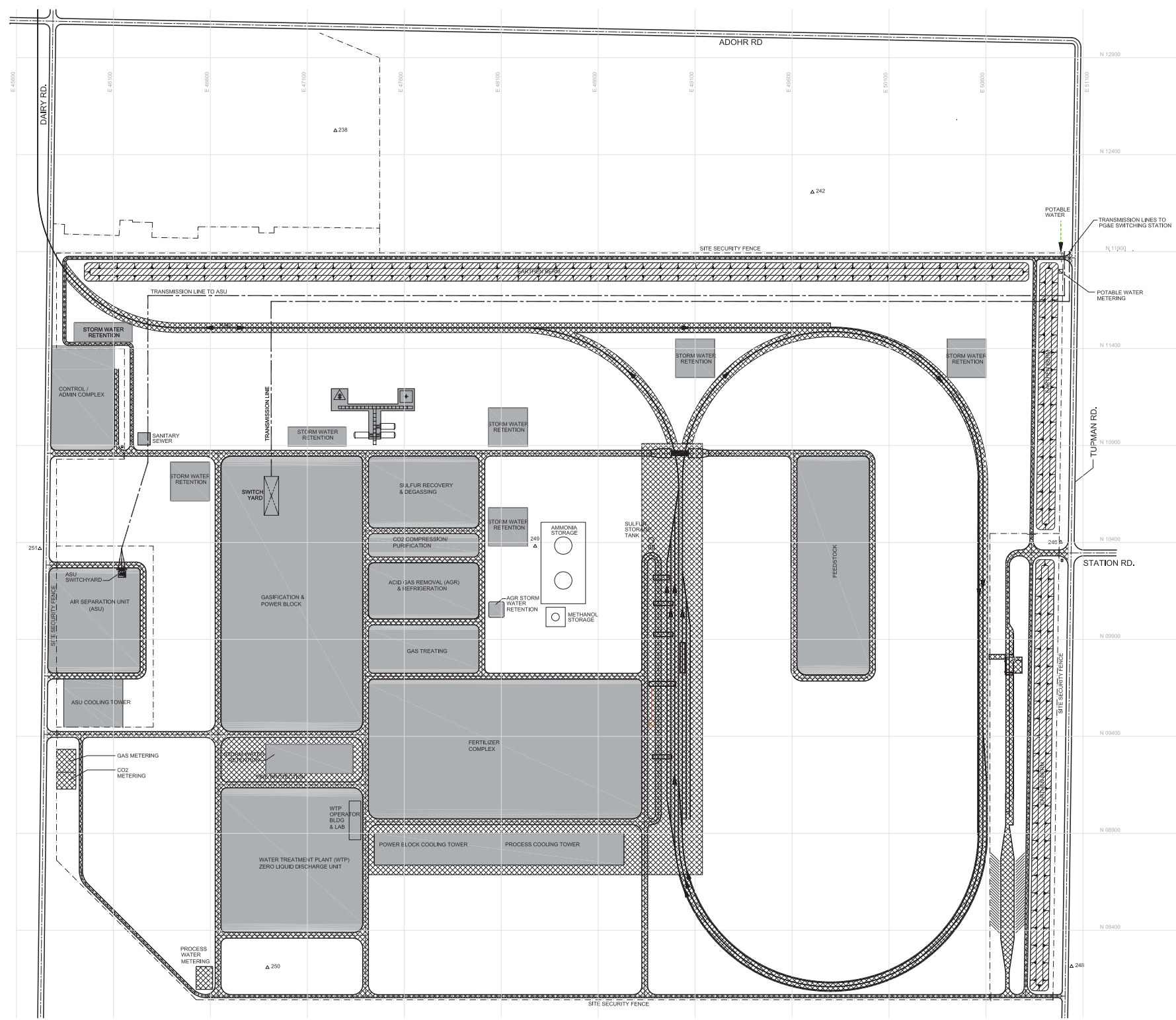
FLUOR

HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

Figure 3-9:
PRELIMINARY EMISSIONS SOURCES PLOT PLAN

SCALE
NONE

DRAWING NUMBER
000-50-SK-0002



LEGEND:

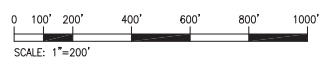
- EL. 288.5 H.P. GRADE ELEVATION
- TOP EARTHEN BERM
- BOTTOM
- PAD AREA
- UNSUITABLE MATERIAL FROM CLEAR & GRUB
- EXCAVATED FILL MATERIAL
- 249 SURVEY MONUMENT POINT NUMBER

EARTHWORK VOLUME	
EXCAVATION *	IMPORT *
850,000 CY	500,000 CY
* SEE NOTES	

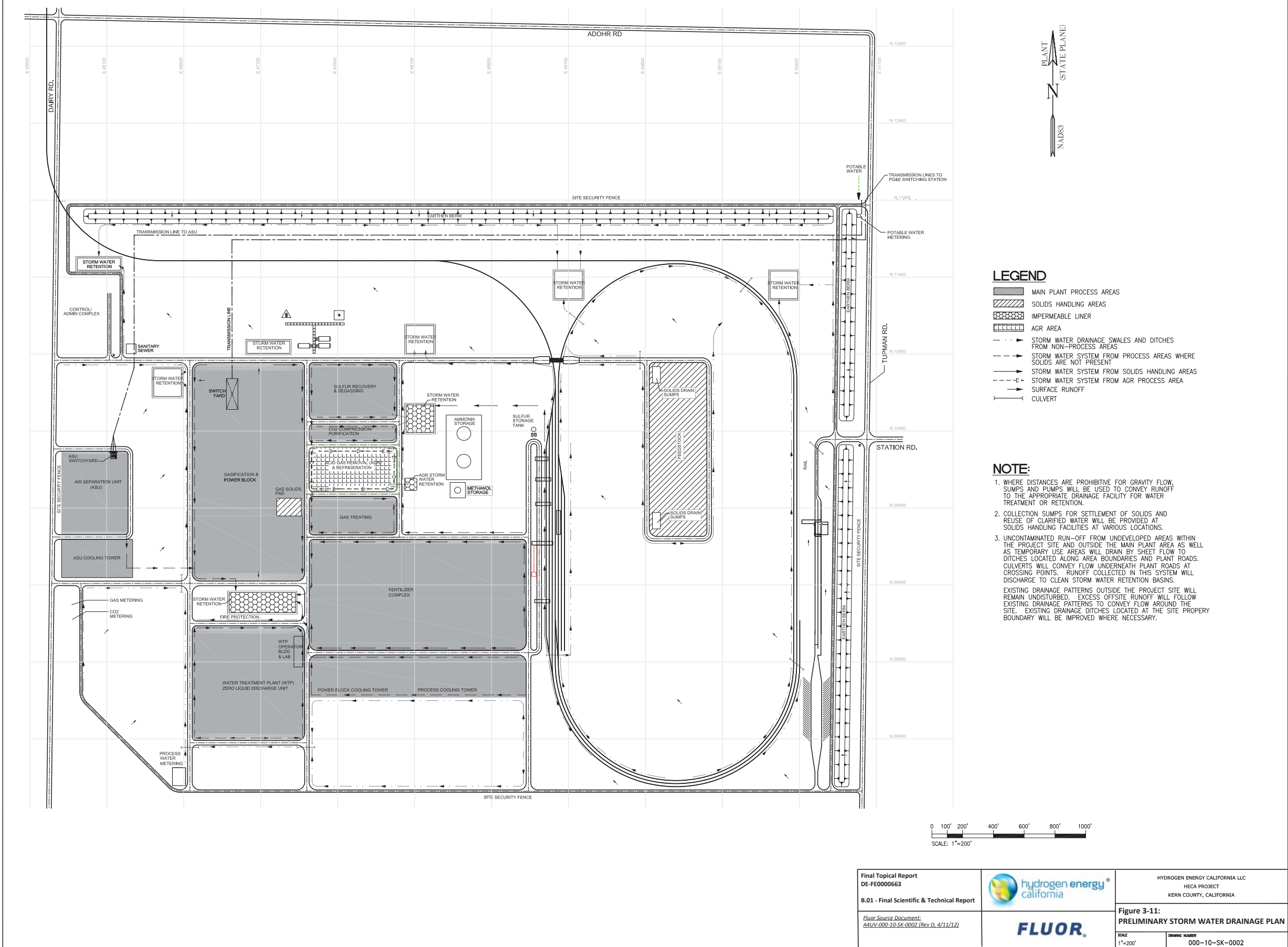
NOTE:

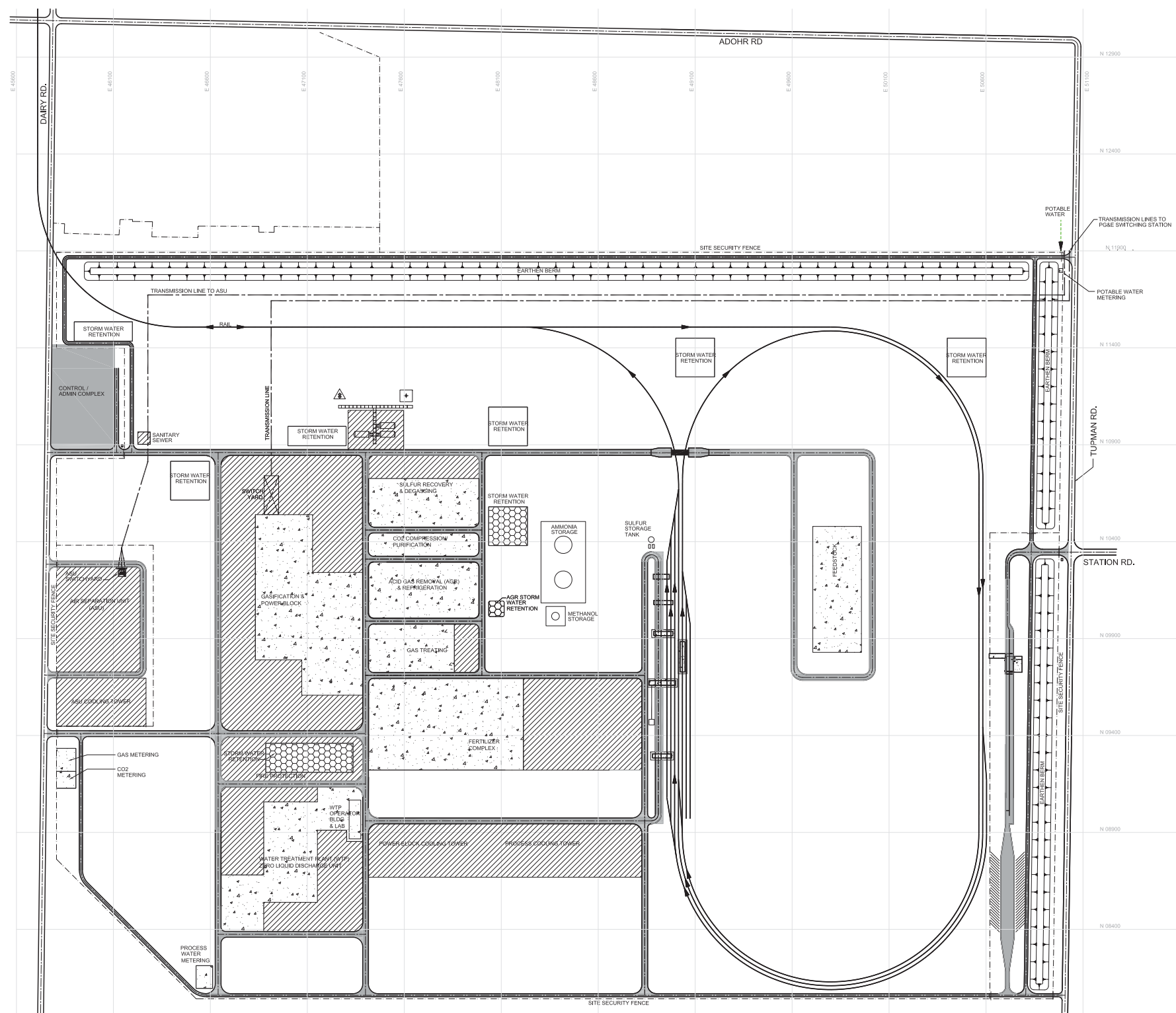
- EARTHWORK QUANTITIES ARE APPROXIMATE AND ARE BASED ON THE PRELIMINARY GEOTECHNICAL INVESTIGATION RECOMMENDATIONS PERTAINING TO THE REMOVAL OF UNSUITABLE SOILS.
- UNSUITABLE SOIL MATERIAL WILL BE EXCAVATED, AND USED TO CONSTRUCT THE EARTHEN BERMS AND TO LEVEL THE OPEN AREAS AS SHOWN ON THE PLAN.
- IMPORT MATERIAL WILL BE USED TO FILL THE VOID REMAINING FROM THE REMOVAL OF UNSUITABLE MATERIAL AND TO RAISE GRADE TO THE ELEVATIONS INDICATED.
- PRELIMINARY EARTHWORK QUANTITIES AND FINAL GRADES WILL VARY DEPENDING ON FINAL GEOTECHNICAL RECOMMENDATIONS AND PLOT PLAN.
- COORDINATE LOCATIONS SHOWN ARE BASED ON THE CALIFORNIA COORDINATE SYSTEM (CCS 83), ZONE V, 2007.0 EPOCH, RELATIVE TO THE NORTH AMERICAN DATUM OF 1983 (NAD 83). ELEVATIONS ARE BASED ON THE NORTH AMERICAN VERTICAL DATUM OF 1988 (NAVD88).
- PIPING AND FOUNDATIONS NOT SHOWN IN PROCESS AREAS FOR CLARITY.
- GRADING SYMBOLS SHOWN DEPICTS PROPOSED ELEVATIONS FOR DELINEATED AREA.

SURVEY MONUMENT DATA			
CALIFORNIA STATE PLANE COORDINATES			
POINT NO.	NORTHING	EASTING	ELEVATION
238	2,312,523.86	6,147,244.89	286.72
242	2,312,206.46	6,149,704.56	286.79
246	2,310,401.98	6,150,985.50	288.23
248	2,308,213.18	6,151,041.09	287.33
249	2,310,380.25	6,148,274.74	287.69
250	2,308,207.70	6,146,894.35	287.45
251	2,310,368.06	6,145,720.47	286.12



Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report <i>Fluor Source Document:</i> AAUV-000-10-SK-0001 (Rev C, 4/11/12)	 	HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA Figure 3-10: PRELIMINARY GRADING PLAN SCALE: 1"=200' DRAWING NUMBER: 000-10-SK-0001



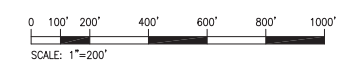


LEGEND

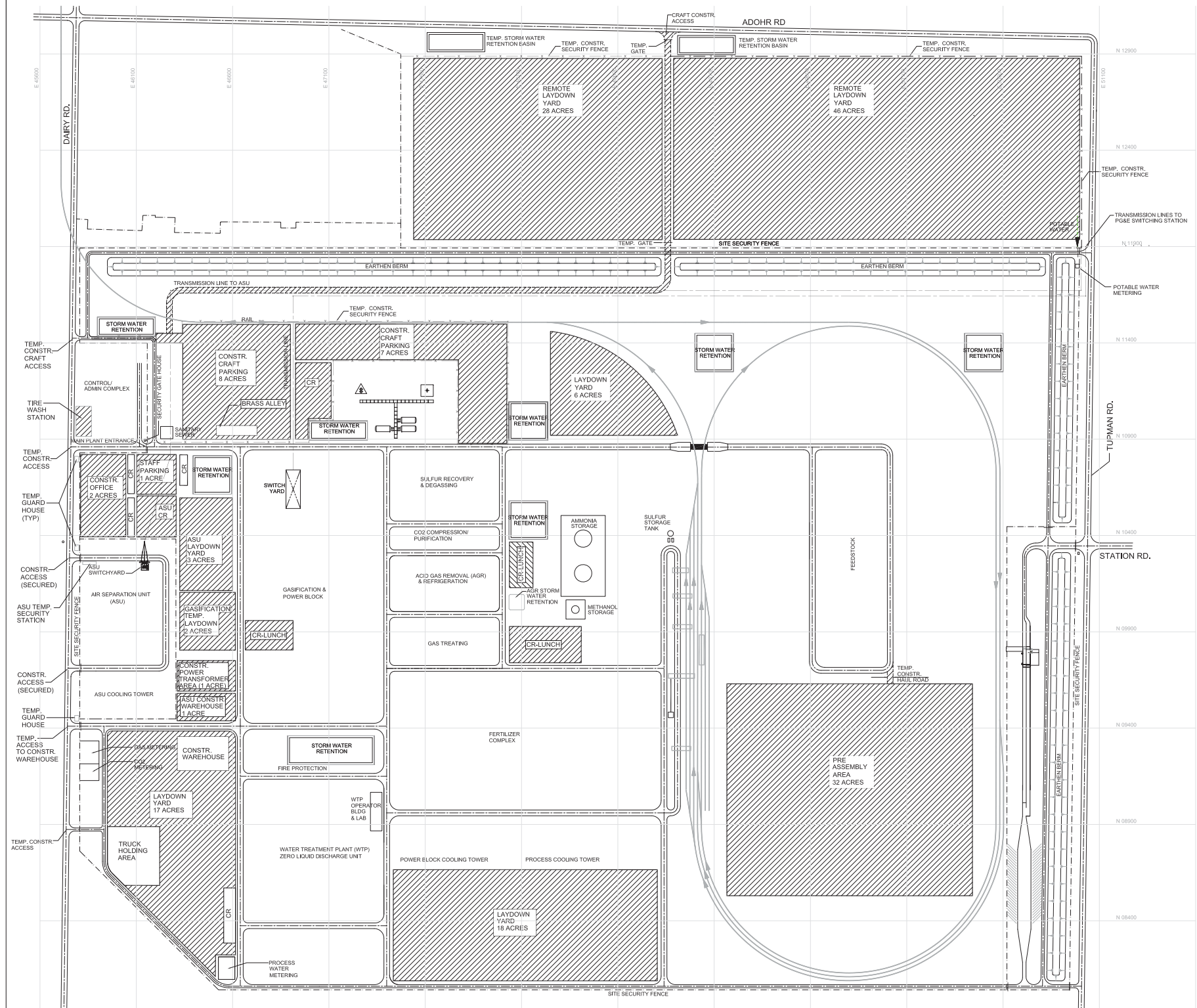
- ASPHALT CONCRETE PAVEMENT
- CONCRETE PAVEMENT
- CRUSHED ROCK SURFACING
- IMPERMEABLE LINER
- TOP
- BOTTOM
- EARTHEN BERM

NOTE:

- PAVING SYMBOLS SHOWN DEPICT PROPOSED SURFACE TREATMENT FOR DELINEATED AREA.
- PAVED DRIVEWAYS, WALKWAYS AND CRANE ACCESS LOCATIONS WILL BE PROVIDED TO SUPPORT PLANT OPERATIONS AND MAINTENANCE. THESE FEATURES WILL BE IDENTIFIED AND SIZED DURING SUBSEQUENT DESIGN AND WILL BE DETAILED ON THE APPROPRIATE CIVIL/STRUCTURAL ENGINEERING DRAWINGS.



Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report Fluor Source Document: A4UV-000-10-SK-0003 (Rev C, 4/11/12)	 	HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA Figure 3-12: PRELIMINARY PAVING PLAN SCALE: 1"=200' DRAWING NUMBER: 000-10-SK-0003



LEGEND

- TEMPORARY FACILITIES AREA
- TRAFFIC FLOW
- FENCE
- TEMPORARY CONSTRUCTION SECURITY FENCE
- TEMPORARY CONSTRUCTION ROAD
- CR-LUNCH CRAFT CHANGING/LUNCH AREA

AREA ACREAGES

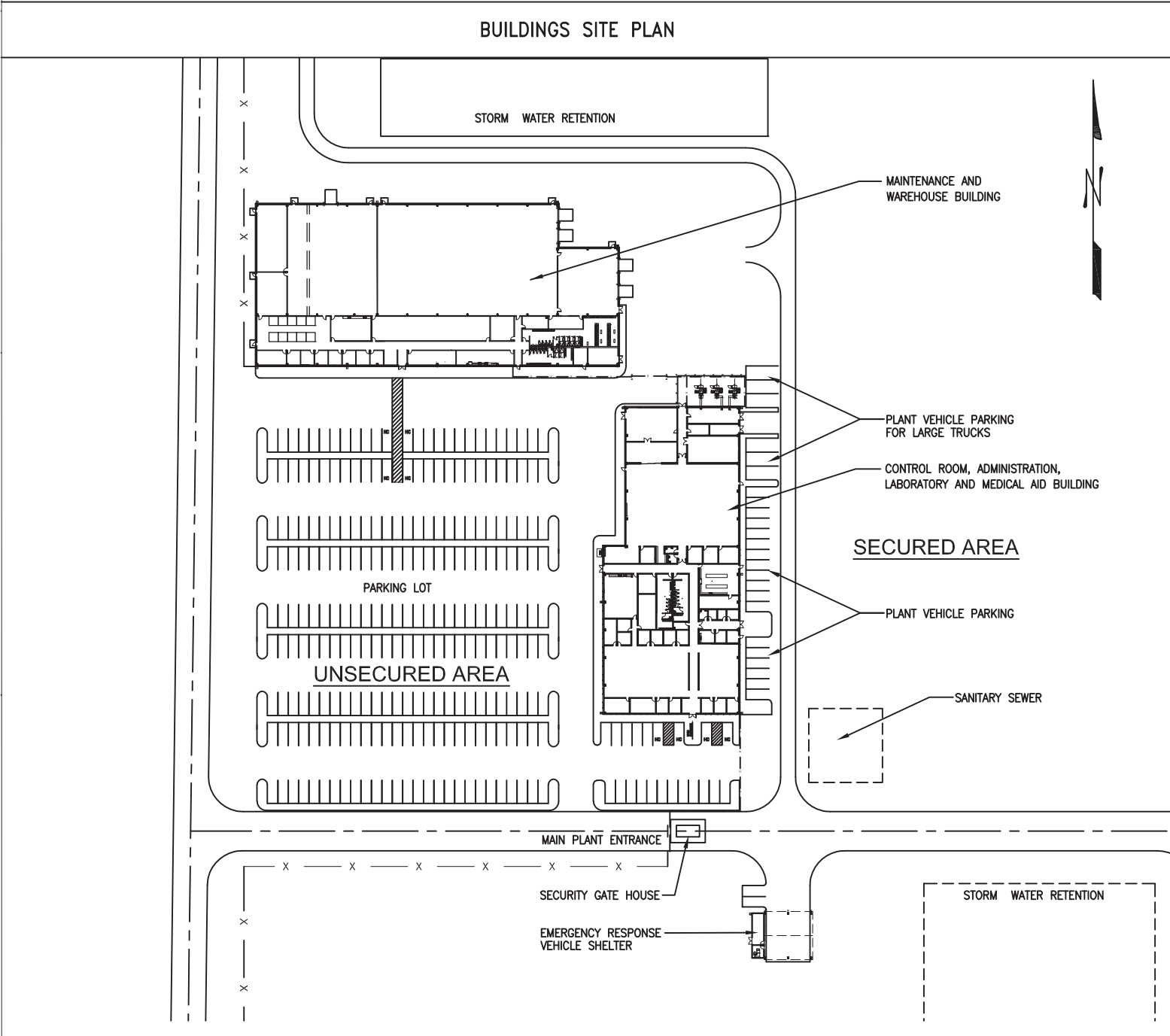
- 453 AC OVERALL SITE (INSIDE PERIMETER FENCE)
- 102 AC INTERIOR TEMP. CONST. FACIL.
- 91 AC EXTERIOR TEMP. CONST. FACIL.

Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report		HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA
Fluor Source Document: A4UV-000-10-SK-0004 (Rev D, 4/11/12)		Figure 3-13: PRELIMINARY TEMPORARY CONSTRUCTION FACILITIES PLAN
SCALE 1"=200'		DRAWING NUMBER 000-10-SK-0004

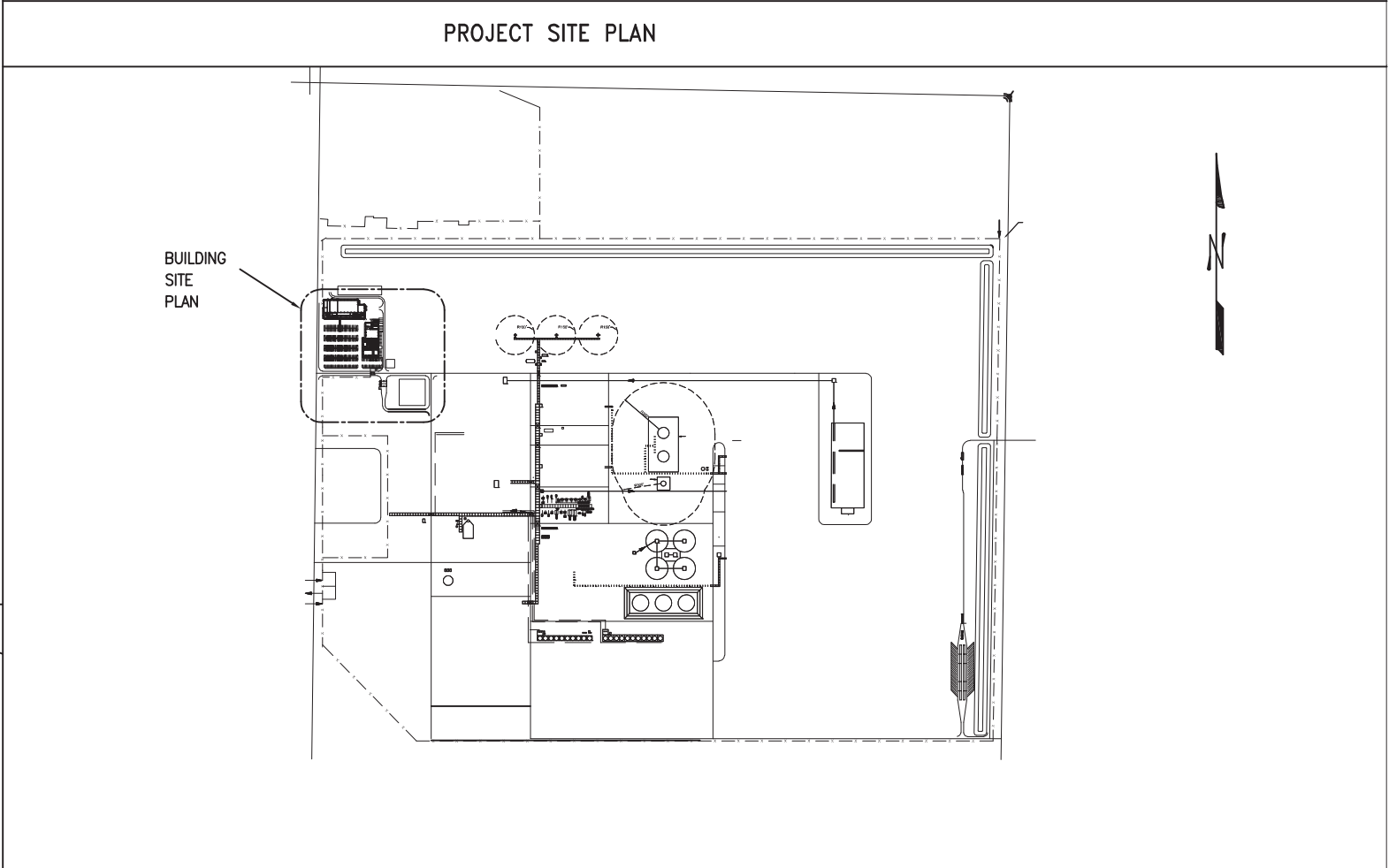
3.13.2 Buildings

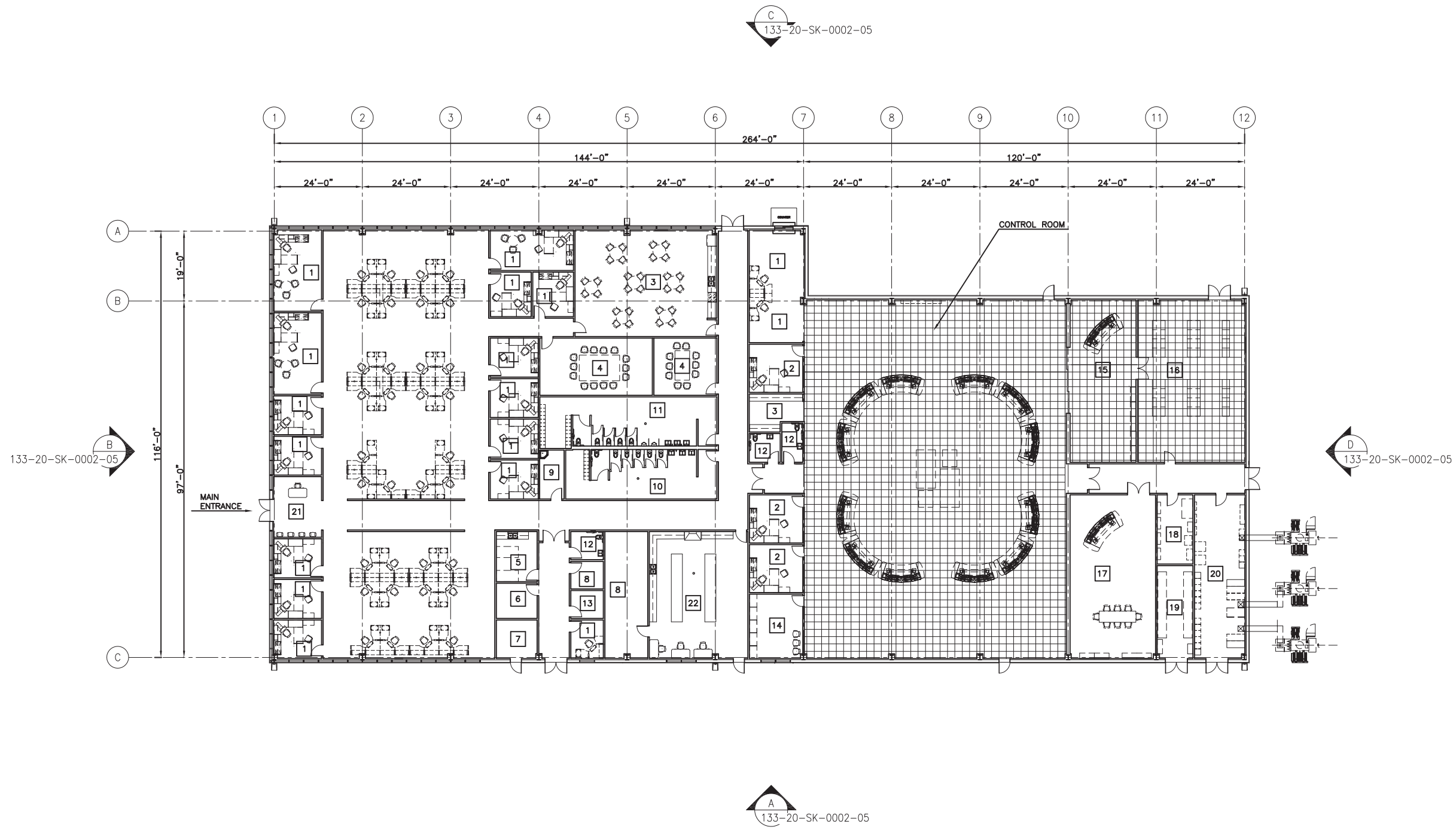
The buildings and shelters shown in the Figures listed below are incorporated into the HECA Project's design to support operations, administration, and worker health and safety.

- Figure 3-14: Architectural Site Plan Cover Sheet (drawing number 133-20-SK-0002-01)
- Figure 3-15: Control Room, Administration, Laboratory and Medical Aid Building – Floor Plan (drawing number 133-20-SK-0002-02)
- Figure 3-16: Maintenance and Warehouse Building – Floor Plan (drawing number 133-20-SK-0002-03)
- Figure 3-17: Emergency Response Vehicle Shelter – Floor Plan (drawing number 133-20-SK-0002-04)
- Figure 3-18: Control Room, Administration, Laboratory and Medical Aid Building – Elevations (drawing number 133-20-SK-0002-05)
- Figure 3-19: Maintenance and Warehouse Building – Elevations (drawing number 133-20-SK-0002-06)
- Figure 3-20: Emergency Response Vehicle Shelter – Elevations (drawing number 133-20-SK-0002-07)
- Figure 3-21: Guard House – Floor Plan (drawing number 133-20-SK-0005-01)
- Figure 3-22: Operator Shelter – Floor Plan (drawing number 000-20-SK-0001-02)



DRAWING LIST	
133-20-SK-0002-01	COVER SHEET
133-20-SK-0002-02	CONTROL ROOM, ADMINISTRATION, LABORATORY AND MEDICAL AID BUILDING-FLOOR PLAN
133-20-SK-0002-03	MAINTENANCE AND WAREHOUSE BUILDING-FLOOR PLAN
133-20-SK-0002-04	EMERGENCY RESPONSE VEHICLE SHELTER-FLOOR PLAN
133-20-SK-0002-05	CONTROL ROOM, ADMINISTRATION, LABORATORY AND MEDICAL AID BUILDING-ELEVATIONS
133-20-SK-0002-06	MAINTENANCE AND WAREHOUSE BUILDING-ELEVATIONS
133-20-SK-0002-07	EMERGENCY RESPONSE VEHICLE SHELTER-ELEVATIONS

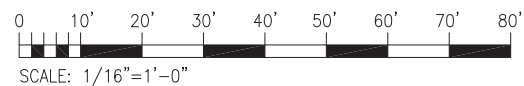


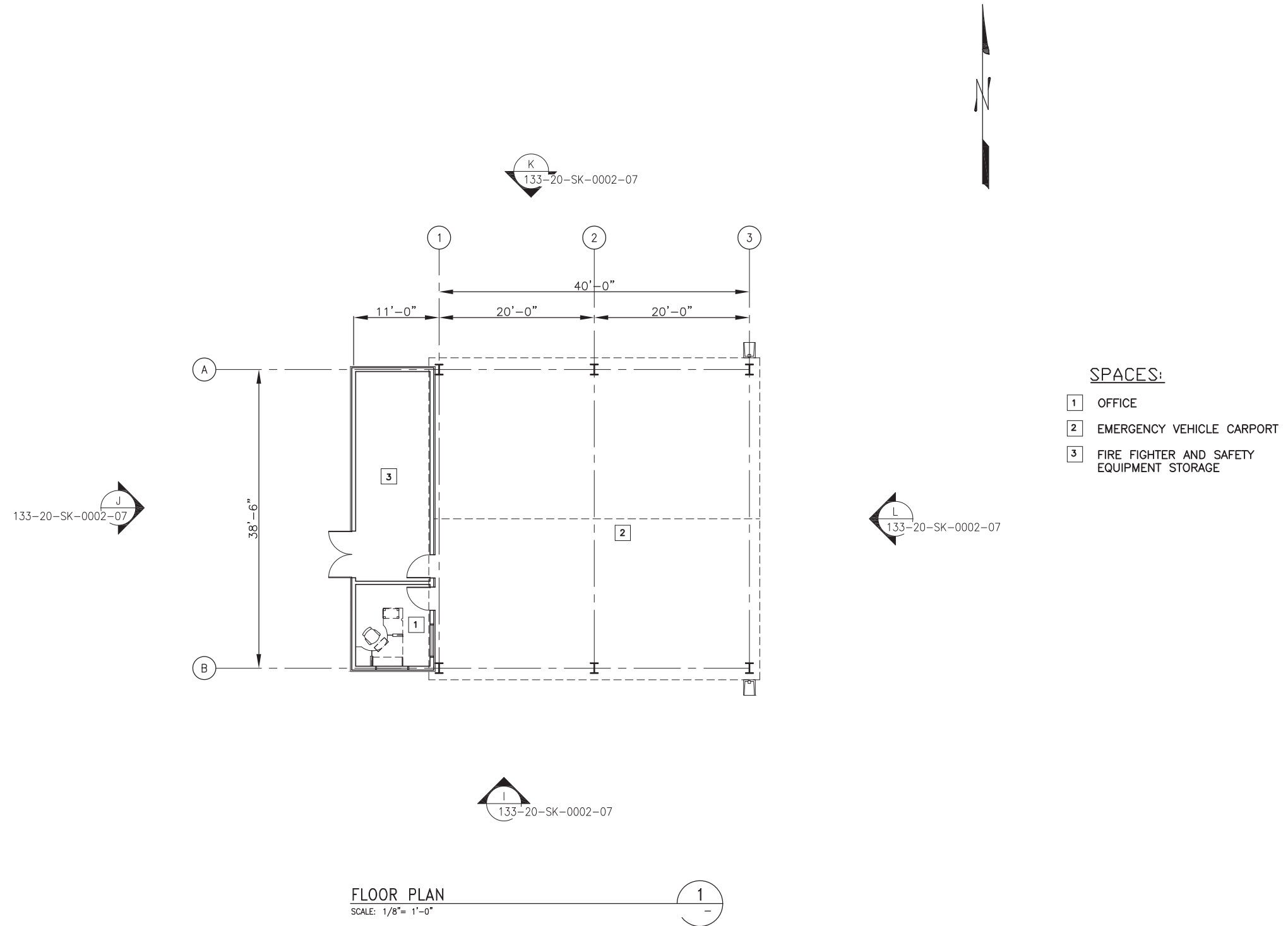


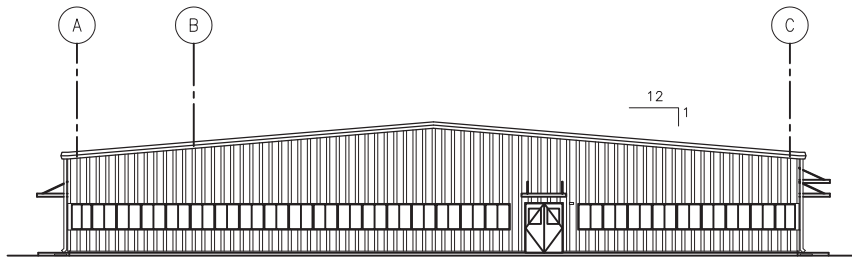
SPACES:

- 1 OFFICE
- 2 OPERATIONS OFFICE
- 3 BREAK ROOM
- 4 CONFERENCE ROOM
- 5 EXAM ROOM
- 6 DRUG TEST
- 7 UTILITY
- 8 STORAGE
- 9 JANITOR
- 10 WOMEN'S RESTROOM/ LOCKERS
- 11 MEN'S RESTROOM/ LOCKERS
- 12 UNISEX TOILET
- 13 HEARING TEST
- 14 LIBRARY
- 15 CONFIGURATION ROOM
- 16 DOCUMENTS/RACK/ COMMUNICATION ROOM
- 17 TRAINING/ SIMULATION ROOM
- 18 UPS ROOM
- 19 BATTERY ROOM
- 20 ELECTRICAL / UPS/ POWER ROOM
- 21 ENTRY
- 22 LABORATORY

FLOOR PLAN
SCALE: 1/16"= 1'-0"
1





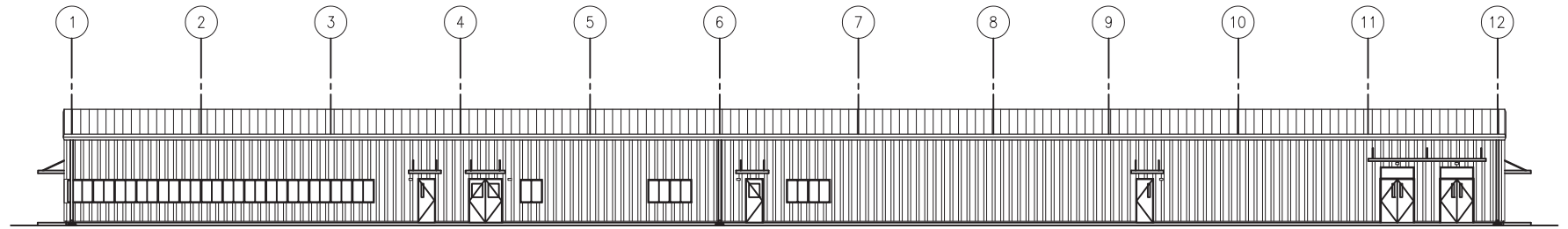


SOUTH ELEVATION

SCALE: 1/16"= 1'-0"

133-20-SK-0002-02

B

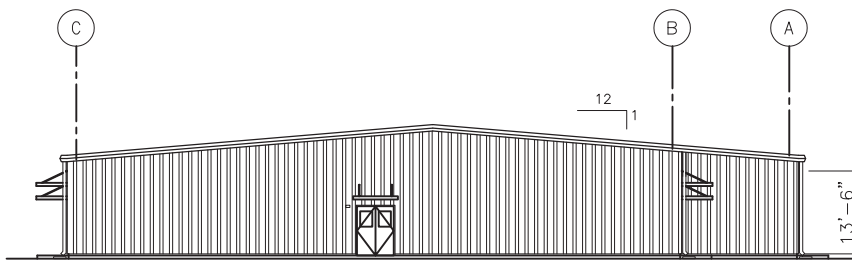


EAST ELEVATION

SCALE: 1/16"= 1'-0"

133-20-SK-0002-02

A

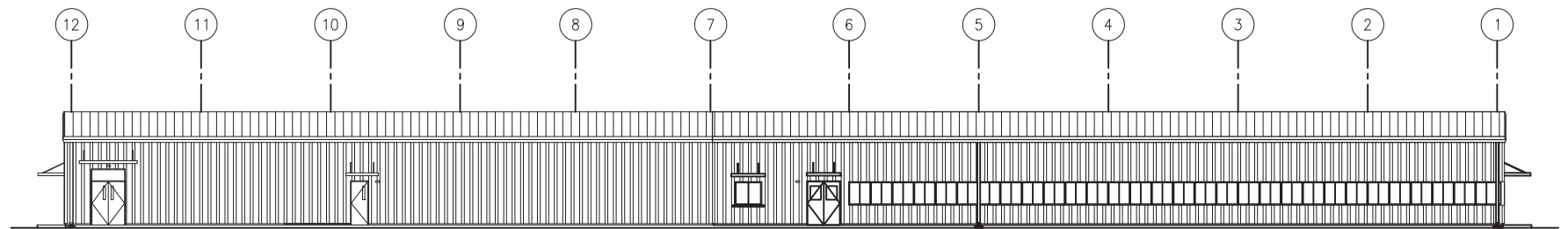


NORTH ELEVATION

SCALE: 1/16"= 1'-0"

133-20-SK-0002-02

D

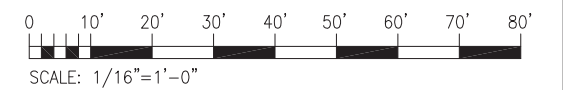


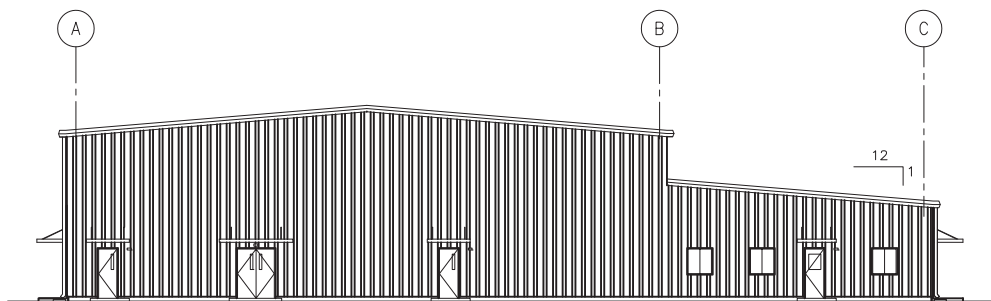
WEST ELEVATION

SCALE: 1/16"= 1'-0"

133-20-SK-0002-02

C



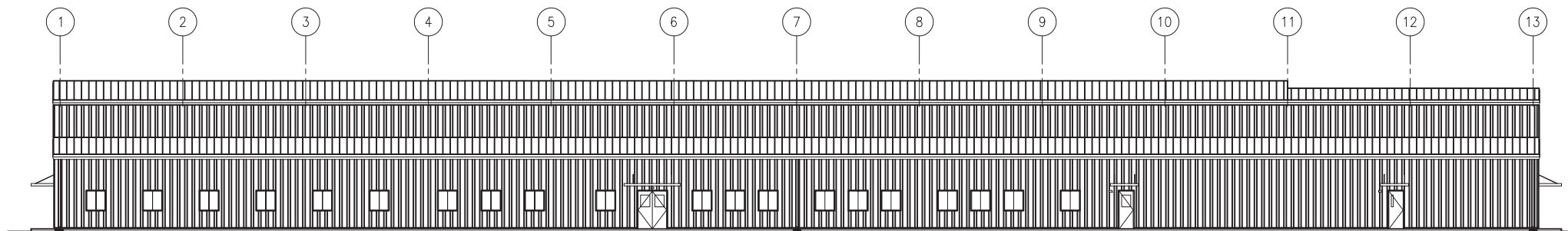


WEST ELEVATION

SCALE: 1/16"= 1'-0"

133-20-SK-0002-03

F

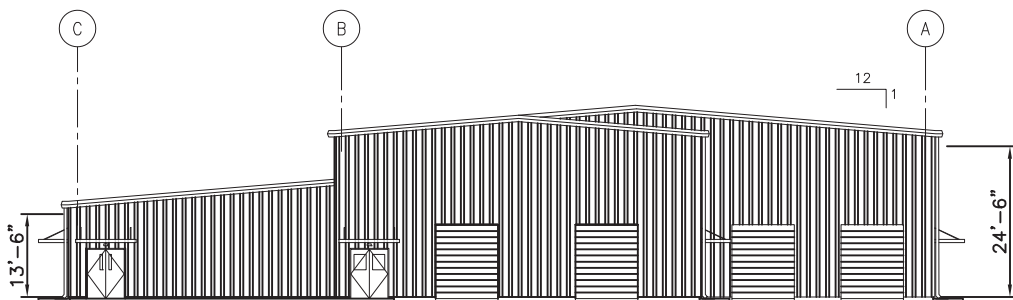


SOUTH ELEVATION

SCALE: 1/16"= 1'-0"

133-20-SK-0002-03

E

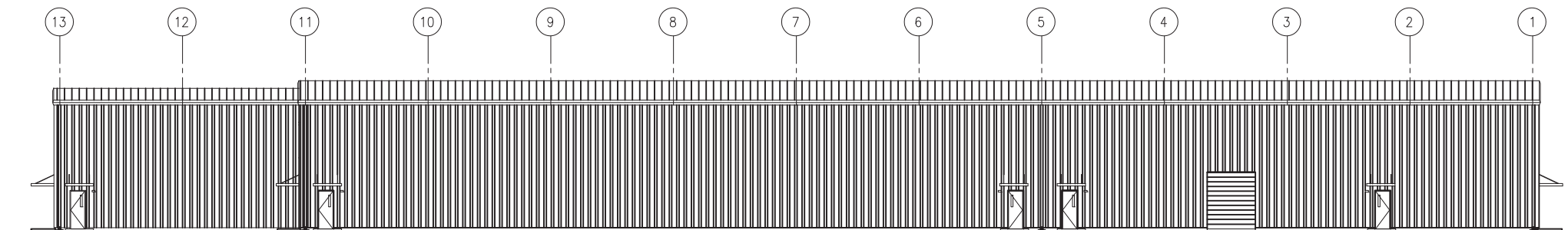


EAST ELEVATION

SCALE: 1/16"= 1'-0"

133-20-SK-0002-03

H

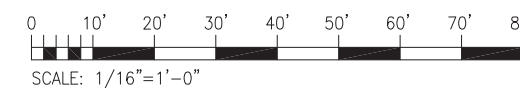


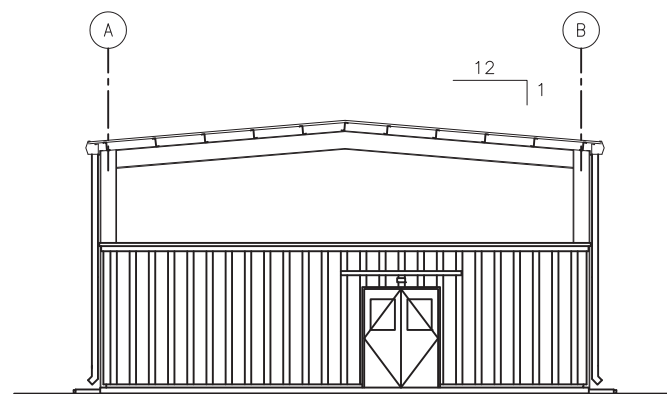
NORTH ELEVATION

SCALE: 1/16"= 1'-0"

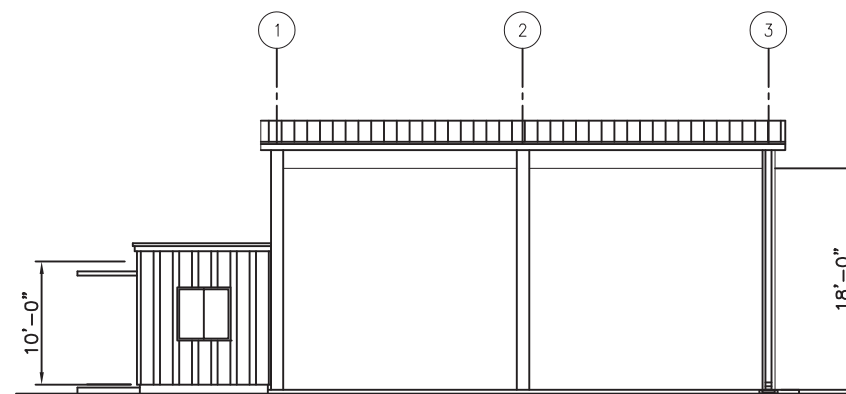
133-20-SK-0002-03

G

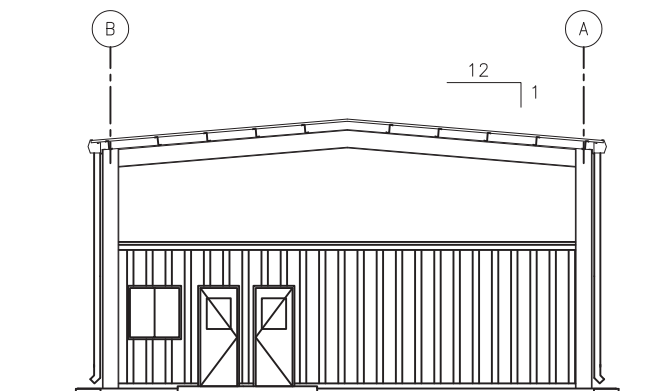




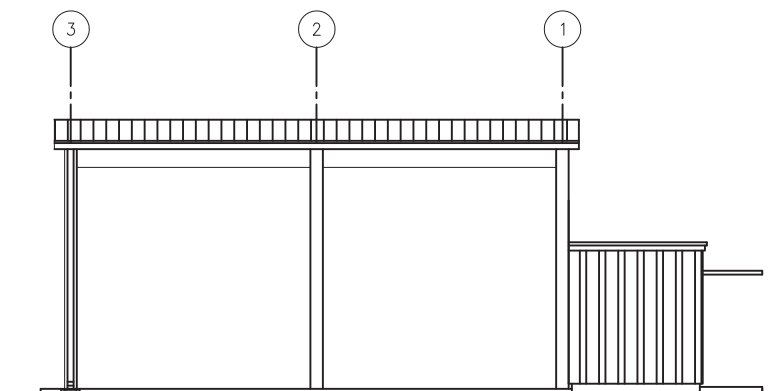
WEST ELEVATION
 SCALE: 1/8"= 1'-0" 133-20-SK-0002-04 **J**



SOUTH ELEVATION
 SCALE: 1/8"= 1'-0" 133-20-SK-0002-04 **I**

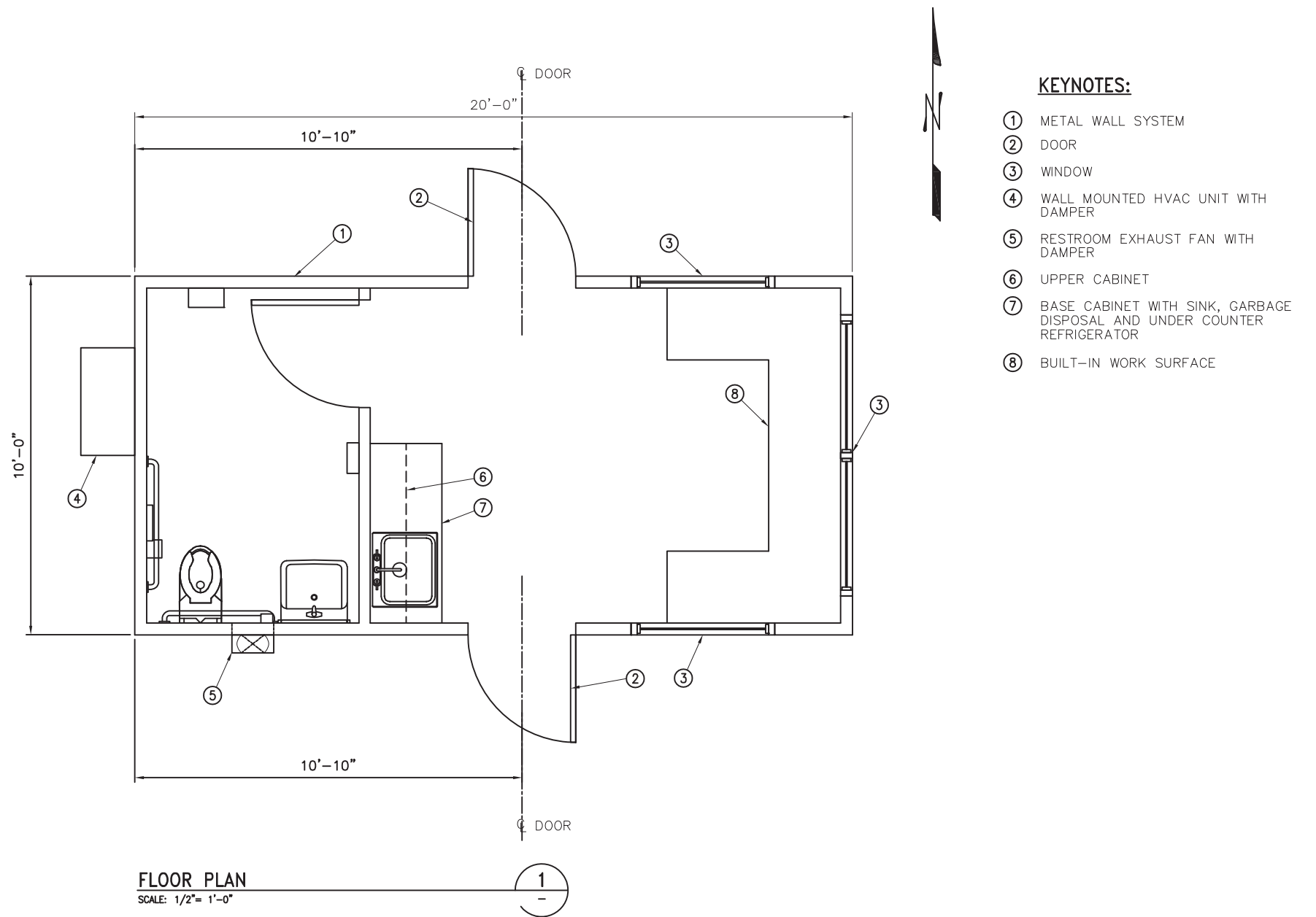


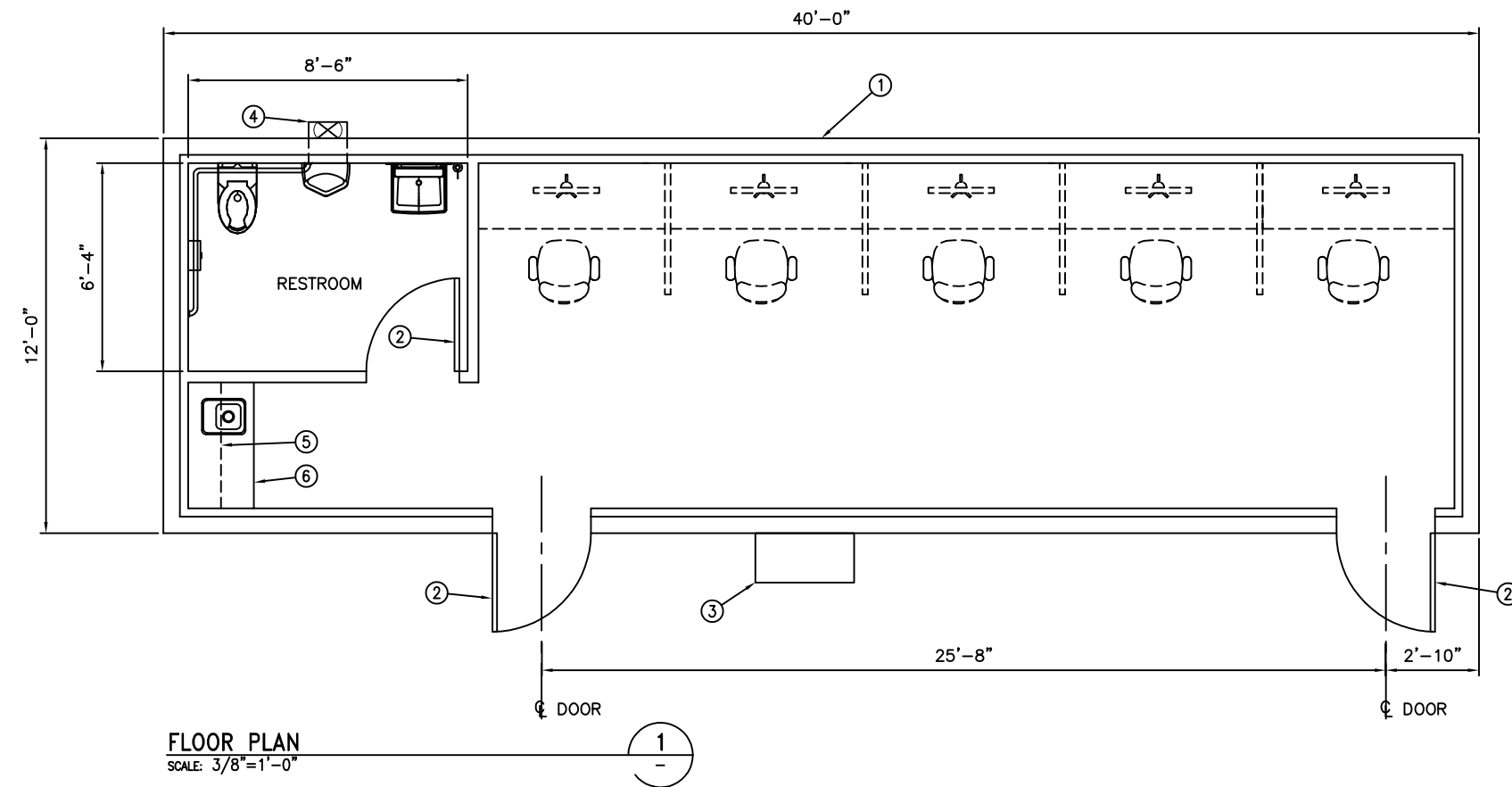
EAST ELEVATION
 SCALE: 1/8"= 1'-0" 133-20-SK-0002-04 **L**



NORTH ELEVATION
 SCALE: 1/8"= 1'-0" 133-20-SK-0002-04 **K**

Final Topical Report DE-FE0000663 B.01 - Final Scientific & Technical Report	 	HYDROGEN ENERGY CALIFORNIA LLC HECA PROJECT KERN COUNTY, CALIFORNIA	
<i>Fluor Source Document:</i> A4UV-133-20-SK-0002-07 (Rev 0, 11/26/12)		Figure 3-20: EMERGENCY RESPONSE VEHICLE SHELTER - ELEVATIONS SCALE 1/8"=1'-0"	DRAWING NUMBER 133-20-SK-0002-07





KEYNOTES:

- ① METAL WALL SYSTEM
- ② DOOR
- ③ WALL MOUNTED HVAC UNIT WITH BLAST DAMPER
- ④ RESTROOM EXHAUST FAN WITH BLAST DAMPER
- ⑤ UPPER CABINET
- ⑥ BASE CABINET WITH SINK, GARBAGE DISPOSAL AND UNDER COUNTER REFRIGERATOR

Final Topical Report
DE-FE0000663
B.01 - Final Scientific & Technical Report



HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

Fluor Source Document:
A4UV-000-20-SK-0001-02 (Rev 0, 11/26/12)

FLUOR

Figure 3-22: OPERATOR SHELTER - FLOOR PLAN

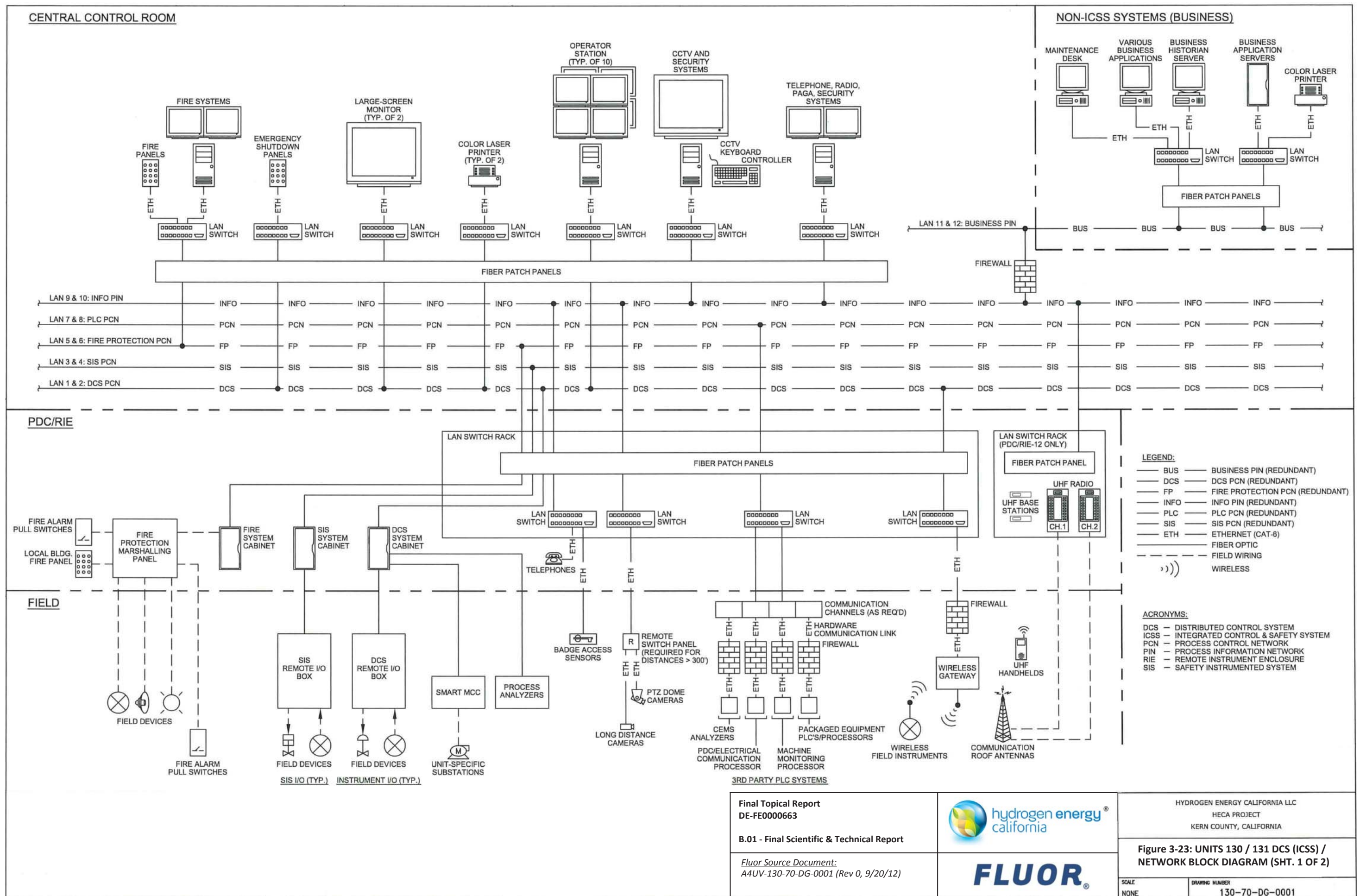
SCALE
3/8"=1'-0"

DRAWING NUMBER
000-20-SK-0001-02

3.13.3 Integrated Control and Safety System

The Project utilizes an Integrated Control and Safety System (ICSS) to monitor, control, operate, maintain and manage operations. The ICSS resides in the Central Control Room, in a safe and secure environment. The ICSS is capable of providing proper plant performance under various operating scenarios and plant throughput capabilities.

The ICSS is illustrated in the DCS (ICSS) / Network Block Diagrams (drawing numbers 130-70-DG-0001 & 130-70-DG-0002), provided as Figures 3-23 & 3-24.



3.13.4 Noise Evaluation

The Planning Center | DC&E conducted a noise evaluation study at the end of the HECA Project FEED phase. The results of the evaluation are contained in the technical memo entitled, *Post-FEED Phase Noise Evaluation Study - Hydrogen Energy California (HECA) Project* dated March 25, 2013.

The evaluation results show that the proposed Project configuration with the appropriate noise control design features will with good probability achieve compliance with the CEC community requirements. During detailed engineering, a refined noise modeling would be conducted to verify this conclusion.

The following narrative, tables, and figures identify the noise receptor areas and summarize the noise control design features and results of the noise evaluation study performed during FEED.

A. Noise Receptor Areas

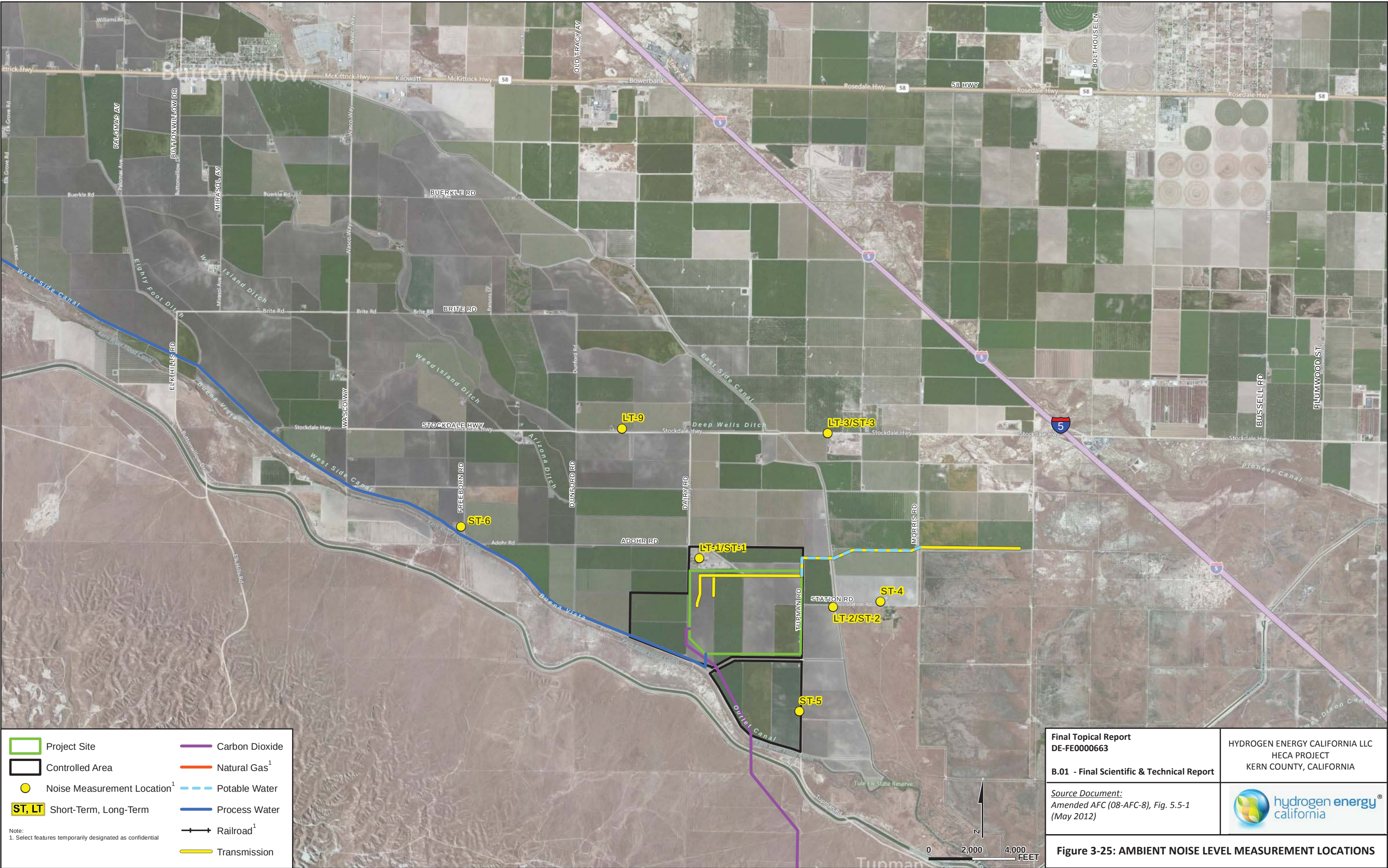
The selected sites of ambient measurements and impact analyses consisted of noise-sensitive receivers located near the Project Site, or along the primary transportation corridor, and two sites located along the transmission and potable water linear routes for the purpose of assessing potential construction-related impacts. The selected sites listed below are considered to be representative of the ambient noise environment in the vicinity of the Project and are shown in Figure 3-25.

- LT-1/ST-1: This location is approximately 370 feet northwest of the Project Site's nearest boundary, 3,000 feet northwest of the center of the Project Site, and is representative of the nearest noise-sensitive receptor. There are two residences located near the measurement site, consisting of one single-family residence and a mobile home. This parcel became part of the Project's Controlled Area. As such, these residences will not be in use during Project construction and operation.
- LT-2/ST-2: This location is approximately 1,400 feet east of the Project Site and 4,000 feet east of the center of the Project Site. There are two single-family residences located at this measurement site.
- LT-3/ST-3: This location is approximately 6,700 feet northeast of the Project Site's nearest boundary, and 9,900 feet northeast of the center of the Project Site. The primary purpose for this location is to determine existing noise levels along

Stockdale Highway. The site is located 15 feet south of Stockdale Highway (23 feet south of the highway centerline), approximately 4,400 feet west of Morris Road.

- ST-4: ST-4 is located approximately 3,900 feet east of the Project Site's nearest boundary, and 6,600 feet east of the center of the Project Site, at the northern extent of the Tule Elk State Natural Reserve.
- ST-5: This location is approximately 3,300 feet southeast of the Project boundary and 5,900 feet south of the center of the Project Site, in the vicinity of a single-family residence. This location is representative of receptors along Tupman Road.
- ST-6: This location is approximately 10,750 feet northwest of the Project Site and 13,500 feet northwest of the center of the Project Site. Sound-level measurements were conducted at ST-6 because of daytime construction of a pipeline taking place in the vicinity of residences located near the intersection of Freeborn Road and Adohr Road.
- LT-7: This location is south of an existing railroad and south of McKittrick Highway. The primary purpose for this measurement location was to obtain ambient noise-level data near a single-family residence in close proximity to existing railroad.
- LT-8: The primary purpose for this measurement location was to obtain ambient noise-level data near a single home residence.
- LT-9: The primary purpose for this measurement location was to obtain ambient noise-level data near a singlehome residence.

The primary sources of noise at locations LT-8 and LT-9 were local traffic during the day and distant traffic along State Route 58 and Interstate 5 during nighttime hours.



Source: Aerial Photo, Bing Maps 2009; Roads, Kern County, 2008; Waterways, US Census Bureau Tiger Data, 2000; Places, ESRI Streetmap Data, 2000-2005.

B. Noise Control Features

In order to meet the overall noise emissions goals, the modeling incorporated the noise control features summarized in Table 3-45. The need for these features and/or additional features would be confirmed through refined modeling in subsequent phases of engineering.

Table 3-45: Summary of Indicated Project Noise Control Design Features

Noise Source	Conceptual Noise Control Feature(s)
Power Block Cooling Tower (12-cell) Process Cooling Tower (13-cell) (64 dBA at 400 feet from tower edge)	This is a low-noise design, and tower vendors can use a combination of slower-speed fans with special blade design, low- noise drive systems, splash control features, and/or tower baffling materials to achieve the specification.
ASU Area Cooling Tower	Same as above on a per-cell basis.
Process Air Coolers	Specify low-noise designs for each air cooler system. Each cell (motor plus drive mechanism plus fan) should be limited to 86 dBA PWL for fan cells >20hp or 83 dBA PWL for fan cells <20hp. Careful attention should be paid to drive mechanics.
Combustion Turbine Train	Vendor specification to meet an overall train limit of 59 dBA at 400 feet (this is a low-noise design relative to nominally standard offerings).
Steam Turbine Train	Vendor specification to meet an overall train limit of 58 dBA at 400 feet (this is a low-noise design relative to nominally standard offerings).
HRSG System	Vendor specification to meet an overall train limit of 58 dBA at 400 feet (this is a low-noise design relative to nominally standard offerings).
HRSG Stack Exit (alone)	Inclusion of a stack silencer to meet a stack exit-only limit of 50 dBA at 400 feet from stack base.
Main Power Block Transformers	Vendor specification to meet limits of 46 dBA at 400 feet or 59 dBA at 100 feet.
Pump Trains (pump+motor) [for trains <100 hp, PWLA should be <83; for 150 to 750 hp trains, PWLA should be <91; and for trains >750 hp, PWLA should be <96]	Specify reduced noise emissions, relative to nominal offerings, for each size train (motor plus driven equipment item). Can be accomplished via noise limit specification to equipment vendor (for a quiet design). Alternatives include the installation of an acoustical enclosure around the pump and drive mechanics or blanketing around the main rotating equipment.
Miscellaneous Rotating Equipment Trains (e.g., blowers, dust collectors, agitators, etc.) [investigate all such sources for noise control, having PWLA > 83]	Specify reduced noise emissions, relative to nominal offerings, for each size train (motor plus driven equipment item). Can be accomplished via noise limit specification to equipment vendor (for a quiet design). Alternatives include the installation of an acoustical enclosure around the item and drive mechanics or blanketing around the main rotating equipment.

Material Handling Structures (including Truck Dumping Area, Train Dumping Area, Transfer Towers, and Feedstock Barn,)	Specify reduced noise emissions, relative to nominal offerings, for sheet metal building with several openings such that they are 60 dBA at 50 feet from any building façade. Assumes acoustical panel specifications for building walls in the design such that interior space noise levels are adequately absorbed/encased within the building shell to meet the assumed emissions levels.
Conveyors (to be enclosed for noise control and dust control)	Specify reduced noise emissions, relative to nominal offerings, such that they are 61 dBA at 50 feet.
Compressors, Blowers, and Expanders	Employ 4-sided, open-topped or closed-top enclosures on selected large trains. Remaining Compressor and Expander Trains above 500 hp or above 86 PWLA should be investigated for noise control such that they achieve noise reduction features for a nominal 15 dB reduction (relative to nominal designs).
Sulfur Recovery Unit Furnaces	Specify low-noise burners to equipment vendors or use noise control enclosures/plenums around burner systems.
Gasifiers	Specify low-noise fuel delivery systems or use noise control enclosures/plenums such that noise emissions are reduced to below 90 PWLA.
Elevated Flare Systems	None indicated at this time (provided vendors can supply equipment meeting Petrochem industry standards). (Assumes operations will be pilot flame only with design flows during occasional start-ups.)
Thermal Oxidizer (mainly used for miscellaneous tank vent discharges in Tail Gas Area)	None indicated at this time (provided vendors can supply equipment meeting Petrochem industry standards). (Assumes operations will be "low" flow; negligibly different than pilot flame only.)
Various Atmospheric Vents	Used of exhaust silencers, as applicable, such that noise emissions are below 83 PWLA.
Other Pump Sets (various)	Noise limit specification to equipment vendor; no more than 85 dBA at 3 feet.
Other Mechanical Equipment not specified above (various)	Noise limit specification to equipment vendor; no more than 85 dBA at 3 feet.
Other Electrical Equipment not specified above (various)	Noise limit specification to equipment vendor; no more than 85 dBA at 3 feet.
Building HVAC units and fans (various)	Noise limit specification to equipment vendor; no more than 85 dBA at 3 feet.

C. Noise Evaluation Results

The noise evaluation results show that the total Project sound power level (PWL) is in compliance with the CEC impact criteria. The Project contributions with noise control features relative to the CEC noise impact criteria are summarized in Table 3-46. The summary of results is also represented graphically in a predicted noise level contour map at Project site, provided as Figure 3-26.

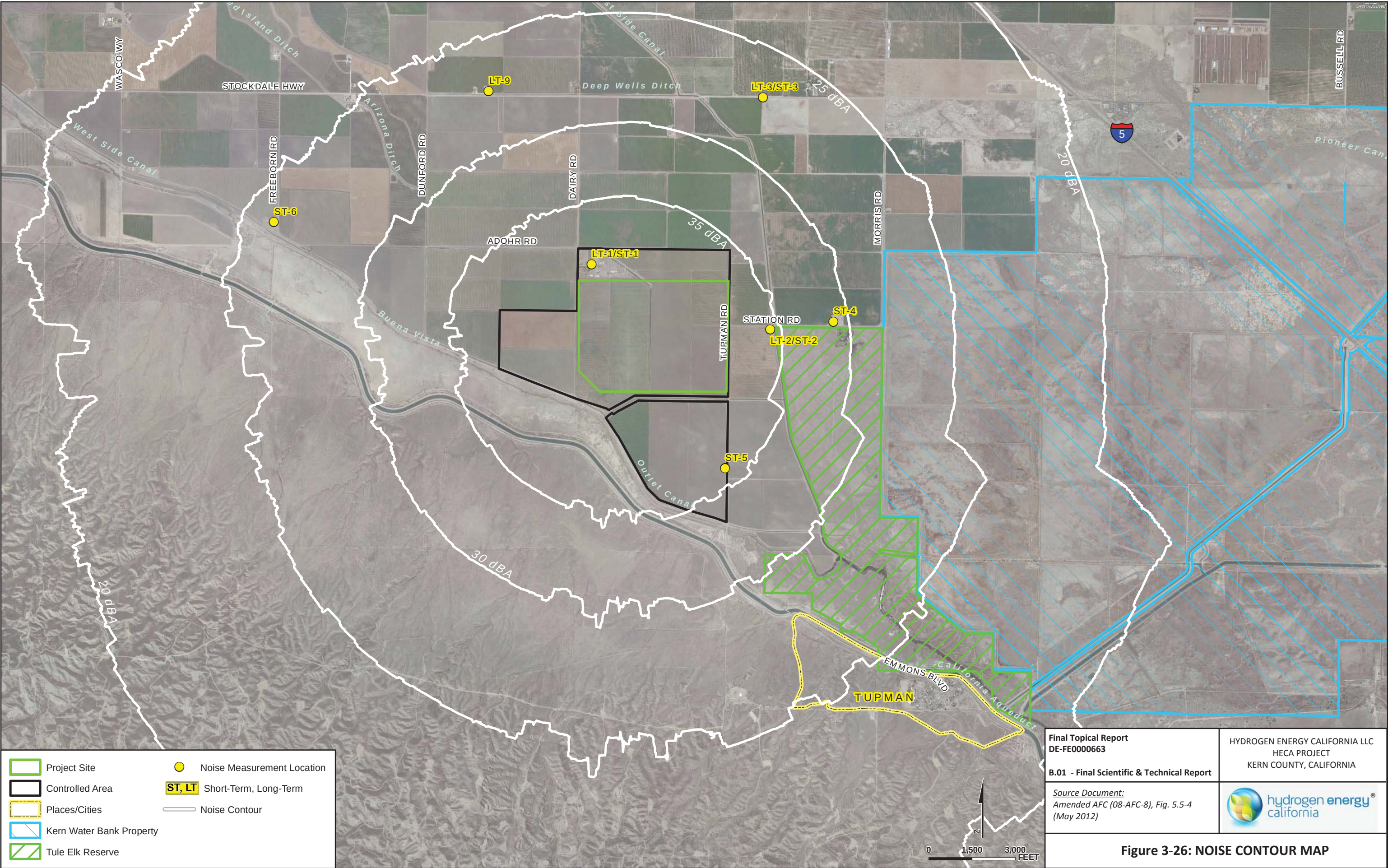
Table 3-46: Summary of Project Contributions with Noise Control Features

Location	Distance from Project Site (feet)		Measured, Late-Night L_{90} ⁽¹⁾ ambient conditions, (dBA)	Design Goal: CEC's +5 dB Late-Night L_{90} ⁽¹⁾ Standard, (dBA)	Predicted, Project Contributions (dBA)	Predicted Project Contributions plus Existing Ambient (dBA)	Comparison to Design Goal
	From Approx. Nearest Boundary	From Process Area Centroid					
OffSite Receptors							
LT-2/ST-2	1,400	4,130	30	35	37	37	2 dB over
LT-3/ST-3	6,700	10,150	30	35	27	32	3 dB under
ST-4	3,900	6,650	37	42	31	38	4 dB under
ST-5	3,300	5,400	33	38	36	38	At standard
ST-6	10,750	13,750	N/A	N/A	26	N/A	N/A
LT-7			50	55	16	50	5 dB under
LT-8			30	35	21	31	4 dB under
LT-9			32	37	27	33	4 dB under
Project Site Boundary							
North		3,686			40	41 ⁽²⁾	N/A
East		3,235			42	42 ⁽²⁾	N/A
South		1,293			51	51 ⁽²⁾	N/A
West		2,339			53	53 ⁽²⁾	N/A

Notes:

⁽¹⁾ The L_{90} level is the sound level exceeded 90 percent of the time and is often considered the "effective background level" or "residual noise level."

⁽²⁾ Assumes that the Power Plant contributions dominate the rural noise environment along the Project Site Boundary.



Source: Aerial Photo, Digital Globe, June 1, 2008; Kern Water Bank Property, Kern County Parcels, 2008; Tule Elk Reserve, California State Parks, 2008; Roads, Kern County, 2008; Waterways, US Census Bureau Tiger Data, 2000; Places, ESRI Streetmap Data, 2000-2005.

3.13.5 Geotechnical

Fluor contracted with Group Delta Consultants, Inc. (GDC) to conduct geotechnical investigations of the HECA Project's site. These investigations were performed in two phases (2009 and 2012). Results and recommendations reflecting the FEED phase investigation are presented in GDC's report entitled, *Final Report - Supplemental Geotechnical Investigation - Proposed Hydrogen Energy California Project (HECA)* dated July 26, 2012. This section summarizes the report's findings and recommendations.

The geotechnical investigation included evaluation of geologic and seismic hazards, as well as analysis of both field and laboratory data to develop geotechnical recommendations for earthwork, roads, and foundations that were necessary to support FEED and the requirements of the CEC. Data from the geotechnical investigation also served as a basis for the Project's preliminary railroad infrastructure layout as described in Section 3.13.6.

The results of the field exploration and laboratory testing programs indicated that from a geotechnical standpoint, the selected site is suitable for construction of the HECA Project. The proposed structures may be supported on mat and spread foundations or driven/auger-cast pile foundations depending on loads, acceptable settlement, and re-compaction of the near-surface soils.

During detailed engineering, the Project would require a more comprehensive geotechnical engineering review of site grading and foundation plans. The report recommended that geotechnical engineering support be provided during construction (monitoring and testing of removal of top soil, excavations, proof rolling the bottom, placement and compaction of fill, approving bottom of foundations, etc.). As a CEC requirement a post-construction report would be prepared to demonstrate compliance with the required grading and foundation plans and specifications.

Details of potential seismic hazards, geologic hazards, field and laboratory test methods, test results, and design recommendations have been extracted from the referenced Geotechnical Investigation and summarized in the narrative that follows.

A. Field & Laboratory Test Methods

Exploratory field tests for the geotechnical investigation included:

- Drilling soil borings from depths of 51.5 ft to 101.5 ft below grade to evaluate subsurface conditions
- Excavating test pits
- Cone Penetration Tests (CPTs) to depths of 33 ft to 74 ft to estimate soil classification, density, strength, and compressibility of the subsurface materials
- Seismic Cone Penetration Tests (SCPTs) to depths of 78 ft and 92 ft to measure shear wave velocity of the soils at the site
- Percolation tests to estimate percolation rate of the soils

The following laboratory tests were conducted to characterize the soils and to develop index, strength, and corrosivity properties of the soils:

- Moisture content and dry density
- Minus 200 Sieve
- Plasticity index
- Pocket penetrometer
- Soil corrosivity (pH, sulfates, electrical resistivity)

B. Results and Recommendations

Based on the results and recommendations summarized below, the selected site is suitable for development of the HECA Project from a geotechnical standpoint.

i) Potential Geologic and Seismic Hazards

Potential geologic and seismic hazards for site such as ground rupture, slope instability, lateral spreading, subsidence, liquefaction, seismic compaction and settlement, tsunamis / flooding, and seismic shaking were evaluated.

The site is not located within an Alquist-Priolo Earthquake Fault Zone. No known active faults are mapped as crossing the site or projecting towards the site in the geologic literature reviewed. The closest active fault is the San Andreas Fault, which is located at a distance of about 21 miles from the project site and is capable of generating a Moment Magnitude (MW) 8.0 earthquake. The White Wolf Fault is located at a distance of about 25 miles can generate a magnitude 7.3 earthquake. The Pleito Thrust Fault is located at a distance of 29 miles can generate a magnitude 7.0 earthquake. With these distances the possibility of ground surface fault rupture at the site is considered low and no displacement due to faulting is anticipated. A California Fault Map is shown in Figure 3-27 and a Regional Fault Map is shown in Figure 3-28.

The site coordinates used in the seismic hazard analysis are -119.3938 (Longitude) and 35.3393 (Latitude). The probabilistic seismic hazard analysis website provided by USGS indicates that the Peak Horizontal Ground Acceleration (PGA) for a mean return period of 475 years is 0.31 g, for alluvium soil condition with a shear wave velocity of 300 m/sec (984 ft/sec) at the subject site.

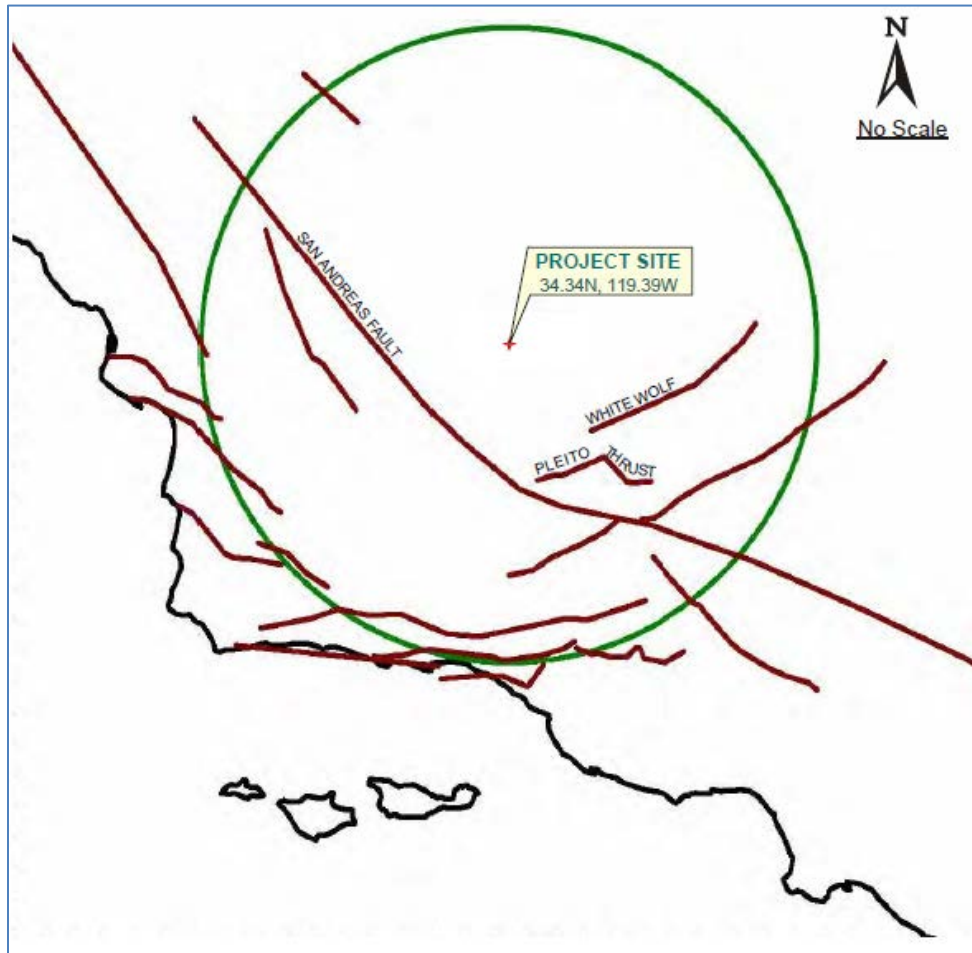


Figure 3-27: California Fault Map

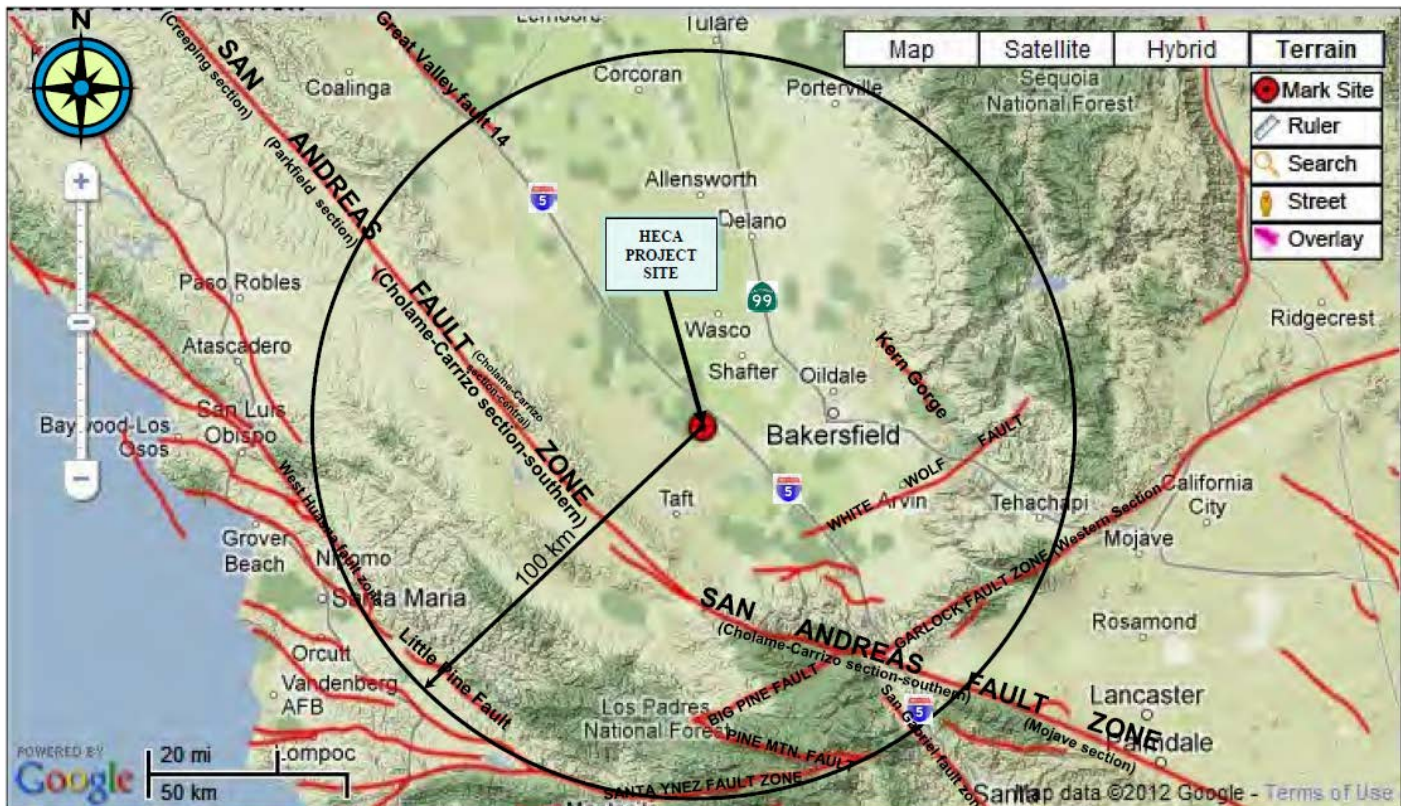


Figure 3-28: Regional Fault Map

The groundwater at the site is deeper than 50 feet. The deep groundwater and the generally dense materials below about 20 feet, indicate that the liquefaction potential at the subject site is considered insignificant and displacement due to lateral spreading is not anticipated. Dynamic settlement of natural condition dry sands at the site under design earthquake loading of 0.31 g is less than 0.25 inches. Differential settlement should therefore be negligible.

The site has no known history of subsidence due to withdrawal of groundwater or oil or due to hydro-compaction. The site is fairly level and not located in a high risk landslide susceptibility zone. The site is generally level without the presence of existing slopes. Post-construction slopes could consist of minimum 2:1 (horizontal to vertical) slopes for berms or ramps. In general, 2:1 slopes are expected to be stable during the design seismic event and slope stability is not a hazard at the site.

The area is inland and at high elevation and is not located near any bodies of water; therefore, tsunami or seiche hazards at the subject site are not present.

The site was also evaluated for the presence of expansive or collapsible soils. The near-surface soils have moderate expansion potential with expansion index between 73 and 83. Most facilities will be supported on large mats or pile foundations. The potential for expansive soils will be considered in the design of shallow foundations or slab-on-grade. Collapsible soils are present in various areas of Central California. Collapse potential of the soils at the site was determined by performing collapse tests in accordance with ASTM D 5333-03 to determine the collapse index I_c , which is the percent collapse when water is added at an applied vertical stress of 2 tsf. The data from these tests indicate that other than one sample at a depth of 2.5 feet, which showed about 3% Collapse Index (moderate collapse potential), all other samples indicate a collapse index of less than 0.58% showing slight collapse potential. Since the upper 4 ft of soils in the plant area will be mass excavated, collapse potential at the site is not a significant factor in foundation design.

Based on the average shear wave velocity in the upper 100 feet between 600 fps and 1,200 fps, the site belongs to Site Class D, Stiff Soil Profile. The results of a deaggregation of seismic hazard indicate that the San Andreas Fault has the largest individual hazard contribution, therefore, is determined to be the controlling fault for the subject site.

ii) Site Preparation and Grading

The site is currently used for growing Alfalfa and Cotton. The borings and CPTs indicate that the uppermost 12 feet of the soils consist of medium stiff to very stiff sandy clay with silty sand layers. Between depths of 12 and 20 to 25 ft, the soils consist of medium dense to dense silty sands and sands. Below about 20 to 25 ft the soils generally consist of low compressibility dense to very dense sands with isolated layers of very stiff clay. No groundwater is present to the 101.5 ft depth explored.

Site grade is to be raised on an average by about 2.5 feet from the existing surface and will require imported granular fill. As an alternate, on-site mining of sands from depths below 5 ft was considered and rejected.

The uppermost 6 to 12 inches of soils containing significant organic matter and roots should be removed and disposed of. Due to variable near-surface soils, most plant structures and tanks can be supported on shallow foundations or mats resting on re-compacted native soils.

The results of the analyses indicate that settlement of about $\frac{1}{4}$ inch could occur due to compression of the underlying soils. Due to the over consolidated clays and sands, settlement under tanks and structures will occur simultaneous with placement of the loading and should be completed within 15 days of completion of the loading.

Post-construction settlements are expected to be small.

iii) Foundations

Structures may be supported on 200-kip design load, driven, 14-in. square, pre-stressed concrete piles tipped into very dense sands present below depths of 20 to 25 feet. However, these piles will have uplift resistance of only about 15 to 37% of the downward capacity. If high uplift resistance is required, about 35 ft long, 18-in. diameter auger cast piles may be used to provide 200-kip design capacity. These piles will have uplift resistance 50% of the downward capacity.

The selection of shallow or deep foundations is dependent on the relative cost of removal and re-compaction, tolerable settlement, in comparison to the costs of pile foundations.

Based on studies performed by Fluor, most of the HECA Project structures will be supported on heavily-loaded shallow mat foundations.

3.13.6 Railroad Infrastructure

This section describes the preliminary railroad infrastructure, its layout, and its operational impacts and efficiencies that are required to support the HECA Project.

During FEED Fluor contracted with HDR Engineering, Inc (HDR), a railway specialty contractor, to develop the HECA Project's preliminary railroad infrastructure layout and its operational impacts and efficiencies. HDR's design concepts are documented in their confidential report entitled, *Hydrogen Energy Project Plant Railroad Facilities and Connection to the San Joaquin Valley Railroad (SJVR) - Railroad Layout and Related Plant Operations*, dated May 2012. The information in this section summarizes HDR's design concept for the HECA Project.

The information in this section summarizes HDR's design concept for the HECA Project. HDR's report provided an analysis of the site conditions, the major plant component locations, preliminary loading and unloading capacity requirements, and the development of the proposed railroad infrastructure layout. HDR's findings indicate the soils should be strong enough to support the anticipated railroad loadings. During detailed engineering, an updated evaluation and report would be conducted to verify the overall rail layout and operational impacts.

To provide for delivery of the coal feed stock and the shipping of products produced by the IGCC "polygeneration" project the plant requires the construction of a railroad loop, coal unloading facilities, product loading/handling facilities, and access roads. A roadway overpass is planned over the south portion of the "Wye" tracks (triangular junction) near the north end of the loop track to provide emergency access.

A. Site Description and Rail Access

The project site is located southwest of Buttonwillow, California, an unincorporated section of Kern County. The site is approximately 453 acres and generally rectangular in shape. The site is located approximately 4.6 miles south of the east-west running San Joaquin Valley Railroad (SJVR) Buttonwillow branch line. Interstate 5 (I-5) runs in a northwest-southeast direction and is located approximately two miles northeast of the site. It provides truck access to the site. Bakersfield, the largest community close to the plant, is approximately 20 miles east of the site.

The project site is generally flat with elevations ranging from 285 feet to 287 feet across the site. This region of California is semi-arid, and predominately a highly irrigated agricultural region. The southwest limits of the site borders the beginning of the foothills of the Coast Range where there is oil production.

The closest rail access is approximately 4.6 miles north of the site where the SJVR Buttonwillow branch runs under I-5. Rail access to deliver coal and ship urea and other by-products is through a new spur track connecting to the SJVR just west of where I-5 crosses the SJVR. Vehicles access the site from I-5 via Dairy Road north and Stockdale Highway east.

The geotechnical report did not make any specific recommendations for the design of the railroad embankment and trackbed section; however the boring logs indicate that the upper 12 feet of soil consists of medium stiff to very stiff sandy clay with silty sand layers. The undrained shear strength of the clays exposed in the test pits indicate that at a depth of about 2 ft, most soils have undrained shear strength of 2 ksf or more and are generally stiff to hard in consistency. The soils after compaction to 90-95% optimum density should be strong enough to support the anticipated railroad loadings.

B. Plant Railroad Layout

i) General

Plant design information developed and provided to HDR by Fluor was the basis on which railroad infrastructure layout was developed. Major plant components and their respective locations, such as the coal unloader, coal conveyor and storage area, and the product loading areas including the railcar loading of solid urea, UAN solution, liquid sulfur, and gasification solids, and retention basins, and roadway access points, were considered in the design. Figure 3-29 entitled “On-Site Track Layout” provides an illustration of the railroad infrastructure on the HECA site (Note: this illustration utilizes an “early in FEED” version of the plot plan as background. Although the background is slightly different than the “end of FEED” Overall Plot Plan provided in Section 3.9, the railroad infrastructure concepts described in this section remain consistent with the “end of FEED” Overall Plot Plan configuration).

Fluor prepared traffic estimates as part of the AFC, and HDR utilized this information to estimate the capacity requirements for the loading and unloading of the various materials required at the proposed plant. One unit coal train is anticipated to be on-site at any given time. The loop design accommodates two unit trains on-site allowing a loaded train to pass an empty train (on-site) eliminating the need for a passing siding on the spur track or the SJVR.

BNSF has proposed to initially operate up to 120-car unit trains routing its trains over Tehachapi Pass on its way from Peabody Energy’s Lee Ranch and El Segundo coal mines in northeastern New Mexico. When BNSF completes its siding lengthening project over Tehachapi Pass, it will be feasible to increase unit train lengths to 135-cars. The proposed HECA design has the capacity to handle 135-car trains with six locomotives for a total train length of just over 7,600 feet. On average 8 unit coal trains are expected to be unloaded each month.

Products are loaded into empty railcars at the plant and prepared for departure. The estimated product volume is 198 loaded outbound railcars per week, averaging three inbound/outbound trains per week, or 13 trains per month.

Based on three times weekly rail service to the plant, approximately 3,960 feet of loading/storage track (66 railcars) is required on-site for the by-products. A 3,300 foot siding located at the NW entrance of the plant, and an adjacent 1454 foot spur, is proposed to setout inbound empty railcars for switching to the loading/storage tracks by plant personnel. The siding can also be used to hold an outbound empty coal train as an inbound load coal train arrives if extra capacity is needed.

ii) Track Materials

Track materials proposed for the track on-site include jointed 136 RE (136 lbs/yd) rail with standard 39 foot long rail between joints. 136 RE rail is typical for heavy haul use and used in other facilities similar to this. Crossties will be concrete (8'-6") with resilient fasteners. Timber crossties may be substituted for cost savings depending on the availability and market value during the time of purchase. Ballast will be American Railway Engineering and Maintenance-of-Way (AREMA) standard No.4 ballast with an 8" minimum depth below tie. A 6" layer of aggregate base will be placed between the bottom of ballast and the subgrade. The subgrade will be prepared and graded using native clean soil compacted to a minimum of 90% relative compaction using the Modified Proctor method of compaction testing. Turnouts (switches) will consist of No.9's and No.11's. No.9's are primarily used for yard and setout tracks, where No.11's are used on the main, loop and passing tracks. Derails will be used at various locations to prevent stored railcars from rolling into the foul of other tracks. Bumping posts will be used for the stub ends of the setout tracks.

iii) SJVR Connection & Off-Site Lead Track

A new "industry spur track" connects the plant site to the SJVR track approximately 4.6 miles north of the plant just west of where the SJVR crosses under I-5. The spur enters the plant in the northwest corner of the site and crosses Adohr and Dairy roads. Design of this "industry spur track" was outside of HDRs scope.

iv) Loop Configuration

The purpose of the long loop tracks is to receive loaded unit coal trains and prepare them for unloading. The majority of the plant loop primarily consists of two tracks with the exception of the area of the coal unloader where the two tracks converge into one track to allow extra space for the foundation of the loading pit. In addition, a third track wraps around the south portion of the loop to accommodate the staging and storage of loaded product cars.

There is approximately 8,490 feet of track between the clear point (the point where two diverging tracks are 13 feet apart) of the switch north of the unloader and the same switch going around the entire inside loop track. This allows a 135 car unit coal train (and more so with only a 120 car unit train) to occupy the loop without interferences. The two main loop tracks are spaced at 20 foot track centers to allow for railcar inspection. Curves are a minimum of 7°30' (radius of 765 feet) at each corner of the loop. Within the plant train speeds will be restricted to a maximum of 10 mph. Anticipated speed over the coal unloader is 1.0 to 1.5 mph. All loop turnouts (switches) are manually operated (hand

thrown) No.11's and allow diverging move train speeds of up to 20mph. No.11 turnouts are specifically used for the tracks that involve heavy and long trains. Sharper turnouts, such as No.9s, have equivalent curves of greater than 9°, which is sharper than the maximum curvature design criteria of 7°30'.

The outside loop track (L-1) is designated for incoming loaded coal trains as they enter the facility and head in a clockwise direction toward the coal unloader. There is approximately 11,000 feet of clear track space available (M-1 + L-1) for an incoming coal train entering the facility between the clear point (near the switch at Adohr Road on track M-1) and the unloader.

The two main loop tracks (L-1 & L-2) converge into one track on the west side of the loop creating a 1,450 foot section of single track through the coal unloader. This spiral design allows the train to wrap around itself as it is unloaded. By unloading the back half of the train first, an empty train can be held on-site while a loaded train arrives. This creates a desirable operating scenario if for some reason, like weather delays or a derailment, inbound trains get bunched up at the plant. Conversely unloading the train from front to back is equally feasible with this design. The design also provides wide track centers between the loop and by-products tracks to allow extra space coal unloader's structural footings.

An additional outside track (a third track, BP-3L) on the south side of the loop accommodates the staging and storage of product railcars. This third track connects to the outside loop track (L-1) on the east side of the loop at about the half point of the tangent. The other end of this third track connects to the by-product loading yard west of the loop and unloader.

v) Wye Connection

A Wye connection (track W-1) is provided at the northwest corner of the loop. The Wye connection allows loaded coal trains to enter the outside loop and empty unit coal trains to exit the site on either the siding or main spur track. The Wye track also allows the movement of both loaded and empty by-product trains to access the by-product loading yard.

The north leg of the Wye is the entrance to the outside loop track for incoming unit coal trains. The southeast leg of the Wye connects to the inside loop track (L-2), and the southwest leg of the Wye (W-1) is used by empty coal trains and by-product trains to exit the site. The southwest leg of the Wye track also connects the by-product loading yard with the by-product storage siding and setout track in the northwest portion of the facility.

A roadway bridge is proposed over the south end of the two Wye tracks for vehicle access to the inside of the loop.

vi) Product Loading Yard Track

There are three parallel tracks west of and adjacent to the west loop track (next to the coal unloader) designated as the by-product loading yard. The furthest west track, BP-1, extends halfway around the loop to accommodate the storage of loaded railcars and assembly of product outbound trains. The three yard tracks provide for the loading of solid urea, UAN solution, liquid sulfur, and gasification solids. Preliminary design provides for gasification solids and solid urea loading on the west most Track BP-1, and liquid sulfur, and UAN solution loading on the other two tracks, BP-2 and BP-3. The locations of the various loading facilities will be refined during a subsequent stage of engineering. Track BP-1 will have 1,500 feet of clear space in addition to 2800 feet of tail track (BP-1L) connecting to the outside loop. The center Track BP-2 has 1275 feet of clear space and the east Track BP-3 has 1490 feet of clear space. All turnouts (switches) in the yard are hand thrown No.9's.

vii) Main Track, Product Siding and Stub End Track

The main track leading in and out of the facility enters the facility from the north at the NW corner of the facility immediately adjacent to and west of Dairy Road after crossing Adohr Road. The main track (M-1) crosses Dairy Road (part of the facility road at this point) on a 7°30' curve and runs east until it reaches the west leg of the Wye track. A siding (BPS-1) is proposed alongside the main track from Adohr Road all the way to the Wye track to accommodate incoming empty product trains. The siding clear space track length is 3,300 feet. Two stub end tracks along the south side of the siding are proposed to hold up to twenty-one 60-foot railcars. The stub tracks (SO-1A & SO-1B) will be used primarily for the overflow of incoming empty product railcars that do not all fit in the product siding (BPS-1), otherwise these tracks will be used to set out bad order railcars for repair and for switching as needed. The siding has No.11 turnouts and the stub tracks use No.9 turnouts.

C. Plant Operations

The proposed railroad layout balances operational efficiency and cost, while considering possible future expansion. The layout considers both coal unloading and product loading operations occurring both individually and concurrently.

i) Coal Operations

Incoming loaded unit coal trains enter the facility at the northwest corner of the site coming south on the main track (M-1), then follow the track around the first curve (L-1) and then heads east onto the outside loop track. The coal train traverses the loop in a clockwise direction as it approaches the unloader located on the west side of the loop. The lead locomotive positions the train just south of the unloader. At this time, locomotive and railcar inspections are expected to occur. Any set-out of bad order railcars can occur prior to those cars entering the unloader. The train then continues through the unloader as it unloads coal and traverses the inside track of the loop (L-2). As the head end of the train reaches the unloader a second time, the switch just north of the unloader is thrown and the train heads in the direction of the west leg of the wye track (W-1) on its way to exit the facility.

With the current plant layout, two unit coal trains can be held within the facility at any one time. As discussed previously, if the back half of the train is unloaded first then an empty train can be held clear of the main track allowing a loaded to arrive and clear the main track. If the front half of the train is unloaded first, the empty train would have to be run through the coal unloader a second time.

It is assumed that fueling of locomotives will not be done at this facility except in emergencies. It was also assumed that no train crew changes occur at this facility. Crew change point is anticipated to be at the SJVR Bakersfield Yard. If fueling is required, this process can be completed via fuel trucks with temporary spill bladders.

ii) Product Operations

Based on the projected railcar demand for the loading of products within the facility, there will be three 66 car trains per week, and each train will be powered by 2 locomotives. It is assumed that all on-site switching and staging of product railcars is to be performed with a trackmobile (car mover) or switching locomotive by plant employees. This will allow the operating railroad (SJVR) to bring in a train with empties, drop them off, then couple into loads that are ready to depart with little or no additional switching.

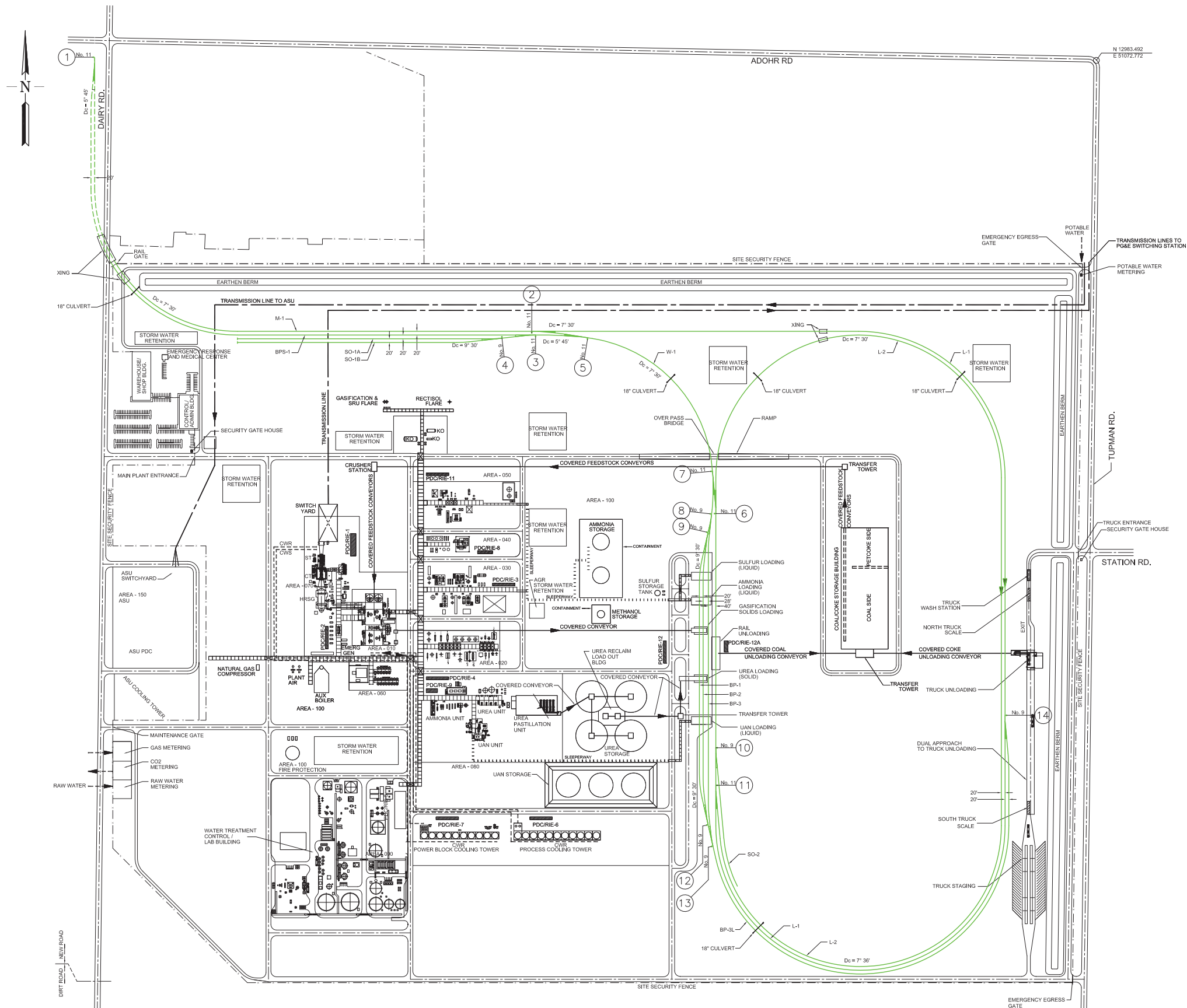
The anticipated operating scenario is that a SJVR train with 66 empty railcars arrives on the main track and pulls into the product siding (BPS-1) in the NW portion of the facility. As this siding fills up with empty railcars, any extra railcars that will not fit will be switched and placed into the adjacent “set out” spur (SO-1). Loaded railcars will be retrieved from one of the three product yard tracks. After successfully conducting a brake test, the loaded railcars will be pulled through the southwest leg of the Wye (W-1) and back onto the main track (M-1).

If loading activity is blocking the north end of the yard and there is no unit coal train on-site, the trainset can run around the loop track to get to the south end of the yard track for access.

The owner furnished trackmobile or locomotive designated to switch railcars is typical of bulk loading/unloading plants like this. Due to the cost of railroad crews performing any switching activities, it is more cost effective to have the plant owner provide the switching of railcars. The methods and operating details can vary greatly at every plant depending on individual plant needs. Trackmobiles are less expensive than locomotives and a car mover, which is usually equipped with rubber tires for roadway use, can be maintained similarly to that of a truck in a motor pool. Trackmobiles also better meet environmental pollution standards. In contrast, a locomotive must be maintained at a designated area and it is restricted to the track. It is recommended the plant owner have two trackmobiles in case one is pulled out of service.

iii) Railcar Repair / Bad Order Operations

Of the three planned stub end tracks within the facility, the one stub track located just south of the coal unloader (SO-2) is used to set out bad order railcars (those with mechanical defects) that are identified during inspection. Railcars are set out on this track prior to going through the unloader. The other stub tracks (SO-1A & SO-1B), which are located south of and adjacent to the product siding and at the east end of the siding, are used for additional empty product railcars, bad order set outs from products trains, general switching, or for coal cars with malfunctioning doors. SO-1A & SO-1B tracks can both accommodate up to twenty-one 60-foot cars and the SO-2 track can accommodate up to ten 53 foot cars.



LEGEND

①

SWITCH OR TURNOUT No.

TRACK DESCRIPTION AND CAPACITIES

TRACK No.	DESCRIPTION	LENGTH	CLEARANCE	CAR CAPACITY
M-1	MAIN LEAD	3482'	3307'	62 (53' CARS)
BPS-1	PRODUCT SIDING	3813'	3211'	53 (60' CARS)
L-1	OUTER LOOP	7496'	7159'	135 (53' CARS)
L-2	INNER LOOP	7045'	6871'	129 (53' CARS)
BP-3L	PRODUCT STORAGE LEAD	2979'	2804'	46 (60' CARS)
BP-1	PRODUCT YARD 1	1693'	1282'	21 (60' CARS)
BP-2	PRODUCT YARD 2	1570'	1276'	21 (60' CARS)
BP-3	PRODUCT YARD 3	1782'	1491'	24 (60' CARS)
W-1	WEST LEG WYE	1290'	1290'	24 (53' CARS)
SO-1A	SET OUT 1A	1417'	1269'	21 (60' CARS)
SO-1B	SET OUT 1B	1418'	1271'	21 (60' CARS)
SO-2	SET OUT 2	755'	600'	11 (53' CARS)



HYDROGEN ENERGY CALIFORNIA LLC
HECA PROJECT
KERN COUNTY, CALIFORNIA

FLUOR

Fluor Source Document:
A4UV-121-10-RP-0001 (Rev 0, 5/12)

Final Topical Report
DE-FE0000663
B.01 - Final Scientific & Technical Report

FIGURE 3-29: ON-SITE TRACK LAYOUT

