Revision 01

TRI-STATE SYNFUELS PROJECT

PROCESS CRITERIA MANUAL

Revision 01

PROCESS CRITERIA MANUAL

TABLE OF CONTENTS

Revision 01

PROCESS CRITERIA

1.0 INTRODUCTION

The Process Design Criteria Manual shall be used as a guideline for preparation of basic process design documents for the Tri-State Synfuels Project. The format for flow diagrams, criteria for specifying major equipment, and piping guidelines are based on generally accepted practices in the chemical and hydrocarbon processing industries.

This manual is intended to standardize general process design philosophy for all units, irrespective of the process designer. If significant deviation from the Process Design Criteria Manual is considered necessary, the originator of the process design package shall so advise Tri-State Synfuels Company in writing. Deviations shall not be made without Tri-State's approval.

Revision 01

PROCESS CRITERIA

2.0 GENERAL

GENERAL SECTION INDEX

PROCESS CRITERIA

2.0 GENERAL

2.1 Scope

2.1.1 Primary Narrative Specifications

This manual provides for an overview of design guidelines, and does not provide the detailed information available in the mechanical, instrumentation, and piping narrative specifications. The metallurgy and economic sections offer general guidelines only and cannot serve as a substitute for judgment in specific applications. Equipment metallurgy will be finalized in a metallurgical flow sheet review meeting as indicated in Paragraph 6.2. The primary narrative specifications to be used in conjunction with this manual are listed below. A complete listing of all narrative specifications is available from CIG (Central Issuing Group).

SP-1001-42-2,A,B,C	Vessel Design Basis Specification
SP-1001-43-1	Process Centrifugal Compressors
SP-1001-43-4	Process Reciprocating Compressors (above 300 kW)
SP-1001-43-5	Process Reciprocating Compressors (below 300 kW)
SP-1001-44-1	Shell and Tube Heat Exchangers
SP-1001-44-2	Air Cooler Heat Exchangers
SP-1001-44-3	Double Pipe Heat Exchangers
SP-1001-45-1	Fired Heaters
SP-1001-46-1	Centrifugal Pumps for General Refinery Service
SP-1001-50-1	General Piping - Process and Utility Design, Layout and Drawing Specification
SP-1001-50-3	Piping Material Specification
SP-1001-70-1	General Instrumentation Criteria
SP-1001-90-33	Site Meteorological Design Data
SP-1001-90-90	Noise

2.1.2 Operating Factors

The Tri-State Synfuels plant shall operate at design conditions 340 days per year. Spare equipment shall be installed where necessary to assure this requirement can be met. Generally speaking, rotating equipment such as pumps require sparing. Centrifugal compressors are not spared, but spare rotor assemblies will be provided for each service including turbine drivers. Reciprocating compressors must be spared. Details of the equipment

PROCESS CRITERIA

2.1.2 (Continued)

sparing philosophy is included in subsequent sections of this manual.

Equipment shall be located in a manner that provides maintenance access. Where necessary, breakout piping spools shall be installed to provide the maintenance access. For areas not accessible by mobile equipment, structural steel should be provided to assist with heavy lifting. The steel is to be installed so a manually operated hoist can be used on a temporary basis. Subsequent sections of this manual provide data on maintenance access for specific types of equipment.

The plant will generally operate at 100 percent of the normal flow through each unit. Periodically, portions of the plant will be shut down for turnaround inspections. During these periods the plant will operate at 50 percent or less of the normal flow. Table 2-1 summarizes the expected range of plant operation.

TABLE 2-1

Plant Area	Trains	Spare Trains	Startup	Normal Operation	Operating at Turnaround
Gasification	3 @ 33% each	0	Individual Trains	3 Trains	1 to 2 Trains
Methanol Synthesis	3 @ 33% each	0	Individual Trains	3 Trains	1 to 2 Trains
Mobil MTG	2 @ 50% each	1	Individual Trains	2 Trains	1 Train
Gasoline Upgrading	1 @ 100%	0	33% of normal	1 Train	1*
Utilities and Off-sites	as req'd	Needed to produce @ 100% availability	0 to 100% of normal	as req'd	as req'd

*Except when these units are on turnaround. At that time the liquid feed is stored in off-site tankage.

PROCESS CRITERIA

2.1.3 Design Factors

2.1.3.1 Material Balances

Material balances for each unit associated with the Tri-State Synfuels project are to be shown as follows:

2.1.3.1.1 Block Flow Diagrams

Material balances for block flow diagrams are to be given on a calendar hour basis. On-stream factor for the plant is 340 days (8160 hours) per year. Component breakdown for each stream is not required.

2.1.3.1.2 Process Flow Diagrams

Material balances for process flow diagrams are to be given on a stream hour basis. Each stream is to be shown by component breakdown. Section 3.2 gives a typical example for the material balances.

The material balances must show the expected flow through each item of equipment.

2.1.3.2 Equipment Design

The process flow diagrams will form the basis for the equipment design. Each licensor will determine the design basis for each item of equipment associated with his process. Excessive overdesigns by the licensor are to be justified to Tri-State in writing.

PROCESS CRITERIA

2.2 Climatic Data

2.2.1 Temperature

(Also see Table 4-4 in the Utilities Section of this manual.)

a. Design Wet Bulb Temperature

Where approach to wet bulb only determines the design, the approach to wet bulb temperature equals the difference between temperature to which water is actually cooled and the wet bulb temperature.

Ambient design wet bulb temperature is 79°F.
Corresponding dry bulb temperature is 94°F.

Note - Those dry bulb and wet bulb temperatures (°F) which are not exceeded more than 2.5 percent of the time during the warmest consecutive four months as determined by the mean wet bulb temperature.

b. Design Dry Bulb Temperature

Where approach to dry bulb only determines the design.

Design dry bulb temperature is 96°F.
Corresponding wet bulb temperature is 81°F.

Note - Those dry bulb and wet bulb temperatures (°F) which are not exceeded more than 1 percent of the time during the warmest consecutive four months as determined by the mean wet bulb temperature.

c. Winter design dry bulb temperature is 6°F.

d. Temperature extremes.

Dry bulb temperature is 108°F (max), -23°F (min).
Wet bulb temperature is 90°F.

Remarks - The design for freezing conditions is -5°F with a 30 mph wind.

e. In using the above design figures, allowances are to be made as necessary because of design and surroundings (e.g., for cooling towers it is the designers' responsibility to add the recycle allowance as well as any allowance necessary because of the effect of surrounding equipment).

PROCESS CRITERIA

2.2.2 Pressure

Average barometric pressure = 14.5 psia.

2.3 General Design Considerations

2.3.1 The narrative specifications indicate the standards that must be used for the design and fabrication of the equipment. Deviations from these standards are not permitted without prior approval of Tri-State Synfuels.

2.3.2 The design, construction and operation of this facility must conform to all applicable local, state and national laws covering the release of hazardous materials to the environment.

2.3.3 The measurement and rating of noise shall be in accordance with SP-1001-90-90. This specification stipulates the maximum permissible exposure for industrial workers to be an equivalent noise level of 85 dBA for an 8 hr. day/40 hour work week.

Since the concept of noise exposure embodies time as well as level dependence, an area in which ambient noise level is in excess of 85 dBA may constitute a potential noise hazard but will not warrant treatment if nobody works there for long periods. Treatment is therefore only justifiable where the ambient noise level is in excess of 85 dBA and some operators are subject to long exposure times. The following Table 2-2 gives OSHA Noise Exposure Limits.

TABLE 2-2

OSHA NOISE EXPOSURE LIMITS

Duration Per Day (hours)	Sound Level (dBA)
8	90
6	92
4	95
3	97
2	100
1-1/2	102
1	105
1/2	110
1/4 or less	115

PROCESS CRITERIA

2.4 Measurements

2.4.1 Scope and Application

The units of measurement for the project shall be the English system.

2.4.2 Basic Units of Measurement

The following basic units of measurement will be used on all process design documents:

Linear - inches (in) & feet (ft)
Mass - pounds (lb) & tons (T) (Note 1)
Flow
  Gas - (large) - standard cubic feet/minute (SCFM) (Note 2)
        (small) - SCF/hour (SCFH)
  Liquid (large) - gallons/minute (GPM)
         (small) - gallons/hour (GPH) (Note 3)
  Steam and condensate - pounds/hour (lb/h)
Temperature - degrees Fahrenheit (°F)
Pressure (gauge reading) - pounds/square inch (psig)
Pressure (absolute) - pounds/square inch (psia)
Pressure (differential) - pounds/square inch (psi)
Vacuum (gauge reading) - psia or inches of Mercury absolute
Heat - British Thermal Unit (BTU)
Heat Flow - BTU/hr
Power - horsepower (HP)

Notes:
1. ST = short ton (2000 lb)
   LT = long ton (2240 lb)
   tonne = metric ton (2204.6 lb)
2. SCFM is measured at 1 atmosphere (14.696 psia) and 60°F
3. Small flows are defined as flows less than 0.5 gpm

PROCESS CRITERIA

3.0 FLOW DIAGRAMS

FLOW DIAGRAMS SECTION INDEX

Revision 01

PROCESS CRITERIA

3.0 FLOW DIAGRAMS

3.1 General

3.1.1 Definitions

a. Process Flow Diagrams - Process Flow Diagrams depict the overall process flow scheme. They shall be prepared showing basic process flow; and the equipment, piping and instruments necessary for clear process definition shall be shown. Major process flow lines shall be identified with a number referencing the line to the Material Balance which shall be shown on the flow diagram or typed on material balance forms issued separately.

b. Metallurgical Flow Diagrams - The Metallurgical Flow Diagrams show the same data as the Process Flow Diagram except that:

1. Material balances are not shown.

2. Flow rates are not shown.

3. The material of construction of major process equipment and piping are shown, along with the corrosive conditions including temperature and pressure.

c. Mechanical Flow Diagrams - Mechanical Flow Diagrams show all process equipment (and requisite drivers), piping, instruments and control logic required for the mechanical design of a process unit.

d. Utility Flow Diagrams - Utility Flow Diagrams show for utility systems the same general information as Mechanical Flow Diagrams show for process systems.

3.1.2 Flow Diagram Sizes

Flow Diagrams will be made on mylar whose size is 24 inches high by roll length. Special circumstances may require the drawing to be 30" high. Approval must be obtained from Tri-State for its use. They will be sectionalized to facilitate microfilming. The maximum roll length shall be 15 feet. All flow diagrams shall be drawn with ink on mylar.

PROCESS CRITERIA

3.1.3 Job Controlling Document

Mechanical Flow Diagrams must be an accurate schematic representation of the unit being designed. This Flow Diagram must be accurate in all details. Piping changes resulting from equipment and piping layout cannot be made until the Mechanical Flow Diagram has been changed.

Once a Mechanical Flow Diagram has been issued "Approved for Construction" all changes made to the drawing must be signed and dated. The responsible design supervisor must be contacted and the reasons for the change must be explained at the time the Flow Diagram is being altered.

At Fluor all changes to Flow Diagrams must be color coded as follows:

a. Blue pencil is used for deletions;

b. Red pencil is used for additions;

c. All other marks added to the drawings must be ignored.

3.1.4 Numbering Systems to be Used for Flow Diagrams

3.1.4.1 Process Flow Diagrams

The drawing numbering system is given in Section 3.3.4 of the Project Procedure Manual.

3.1.4.2 Mechanical Flow Diagrams

a. Drawing Number - The drawing numbering system is given in Section 3.3.4 of the Project Procedure Manual.

b. Pipeline Number - The pipeline numbering system is given in Section 3.3.7 of the Project Procedure Manual.

c. Instrument Number - The instrument numbering system is given in Section 3.3.3 of the Project Procedure Manual.

d. Title Block - The details for the preparation of the Title Block for each Flow Diagram are given in Section 3.2.7 of the Project Procedure Manual.

3.1.5 Flow Diagram Preparation and Review Procedure

Each licensor/subcontractor will utilize his own procedures to develop and draft all of the required Flow Diagrams. The format for these Flow Diagrams must be as shown in the examples included in this Process Design Criteria Manual. The following tables give Fluor's Flow Diagram procedure. Table 3-1 is the procedure for Process Flow Diagrams and Table 3-2 is the procedure for Mechanical Flow Diagrams.

FLOW DIAGRAM PROCEDURE
PROCESS FLOW DIAGRAM
TABLE 3-1

SEQUENCE	REVISION	ACTIVITY	RESPONSIBILITY	ACTIVITY DESCRIPTION
01	-	Process Flow Diagram Sketch	Process	Originates Process Flow Diagram sketch, reviews with Control Systems Engineer, forwards to Control Systems Design Supervisor.
02	A	Preparation and First Issue PFD	Control Systems Design	Draft original, issue prints to: Control Systems Environmental (Ref.) Metallurgy (Ref.) Piping Engineering/Material Process
03	A	Reviews and Update PFD	Process Control Systems Piping- Piping Material Environmental	Review and updates Process Flow Diagram. Process review comments from other disciplines. Forward to Control Systems Design Supervisor. Repeat sequences 02 & 03 as necessary for additional comments. Revision letter will change in sequence, ie. B. C. etc.
04	R	Tri-State Review of draft deliverable	Control Systems Design	Update original to Rev. "R" forward to engineering coordinator to issue as draft deliverable for review by Tri-State.
05	R	Process Review of draft deliverable	Process	Process Engineering reviews Tri-State mark-up of draft deliverable. Forward to Control System Design supervisor.
06	01	Update and Issue PFD	Control Systems Design	Update PFD at completion of phase 1. Forward to Engineering Coordinator for issue. (See sequence 010)
07	01	Tri-State PFD Conference or Review & Comments	Process	Call and chair Tri-State Flow Diagram Conference or forward Tri-State marked up print to Control Systems Design Supervisor for drafting (at beginning of phase 2).
08	1	Issue PFD "Client Approval Noted"	Control Systems Design Process	Updates original to Rev. 1. Obtain Tri-State approval signature. Issues Rev. 1
09	2	Update & Issue PFD	Process Control Systems Design	Project Process Engineer forwards the conference master to the Control Systems Design Supervisor for drafting and issue to: Control Systems Metallurgy Piping Material Process Vessels Note: The following Metallurgical Flow Diagram development will be performed during Phase 1.
010	-	Metallurgy Conference (Optional for utility and off-site unit. Mandatory for on-site Units.)	Process	Calls and chairs the Metallurgy conference. Departmental Project Engineers from the following departments must attend, others optional: Metallurgy Piping Material Process Control Systems Vessels

FLOW DIAGRAM PROCEDURES
MECHANICAL/UTILITY SYSTEM FLOW DIAGRAM
TABLE 3-2

* NOTE: Follow the revision system as shown during Phase 1 of the project. At the completion of Phase 1, the MFD's will be issued Rev. 01 regardless of their status (draft deliverable-end of Phase 1). During Phase 2, the numbering will continue using the alphabetical given in the table with 01 in front of the letter, ie. 01C, 01D, etc., until the MFD development has reached Rev. 0 status. At that point the revision will once again be numbered as shown on this procedure.

SEQUENCE	REVISION	ACTIVITY	RESPONSIBILITY	ACTIVITY DESCRIPTION
1	-	Mechanical Flow Diagram and/or Systems Flow Diagram	Process	Prepare Flow Diagram sketch using IDDS call dump or manual sketch. Forward to Control Systems Design Supervisor.
2	-	Flow Diagram Status	Control Systems Design	Control System Design will maintain and issue a Flow Diagram Status Chart to all disciplines.
3	-	Flow Diagram Activity Forecast.	Control Systems Design	The Flow Diagram STATUS CHART will also forecast the scheduled revisions for each diagram.
4	A	Draft First check plot	Control Systems Design	Draft check (paper) plot using IDDS or manual drawing and send check plot to process only.
5	A	Process Check	Process	Review first check plot forward comments to Control Systems Design Supervisor. Repeat sequence 4 & 5 as necessary to correctly show the process flows and required equipment. The drawings revisions will be numbered Rev. A1, A2, etc.
6	B	Draft Second check plot	Control Systems Design	Draft Second check (paper) plot. Send to Process Engineering.
7	B	Process/Instrument Check	Process/Control Systems Engineering	Process Engineering review Second check plot. Forward comments to Control Systems Engineering Forward to Control System Design Supervisor.
8	C	Draft First mylar original for distribution	Control Systems Design	Draft Flow Diagram mylar original, Issue print to: Control Systems Piping-Piping Material Process Mechanical
9	C	First Review and Comment MFD-SFD	Control systems Piping-Piping material Process Mechanical	Disciplines should review the diagram and add their comments. Disciplines MUST resolve major conflicts prior to returning marked up prints to control systems design supervisor.
10	D	Second Revision and Issue MFD-SFD	Control systems Design	Revise original and issue prints to: Control Systems Environmental (Ref.) Electrical (Ref.) Mechanical (Ref.) Piping (Ref.) Piping Material Process
11	D	Line and Flow Data Issue	Process	Forward Line and Flow Data to the Piping Material Engineer.
12	D	Second Review MFD-SFD	Control Systems Mechanical Piping Process Environmental	Responsible groups review and update Flow Diagram Specifically: Process Engineer adds: Line and valve sizes- Control Systems Engineer adds: Control Valve sizes - Relief valve sizes -

FLOW DIAGRAM PROCEDURE
MECHANICAL/UTILITY SYSTEM FLOW DIAGRAM
TABLE 3-2 (CONT)

SEQUENCE	REVISION	ACTIVITY	RESPONSIBILITY	ACTIVITY DESCRIPTION
				Piping Material Engineer adds: Line Class designations - Insulation designations - Code breaks (e.g. ASME) - Forward all marked prints to the Control Systems Design Supervisor. Repeat sequences 10 & 12 as necessary for additional comments. Revision letter will change in sequence,ie. E, F, etc.
13	0	Third Revision and issue MFD-SFD	Control Systems Design	Update Flow Diagram original, issue prints to: Control Systems Electrical (Ref.) Environmental (Ref.) Mechanical Piping-Piping Material Process Project (Ref.)
14	0	Fluor Conference MFD-SFD	Process	Calls and chairs Fluor Flow Diagram Conference. Departmental Project Engineers from the following departments MUST attend. Others are optional: Control Systems Engineering Manager and/or Area Project Engineer Mechanical Piping - Piping Material Process Project Process Engineer forwards conference master to the Control Systems Design Supervisor
15	1	Fourth Revision and issue "For Approval" MFD-SFD	Control Systems Design	Revise original Obtain Fluor approval signatures—Process and Control Systems. Issue for Client approval Rev. 1.
16	1	Client	Process	Project Process Engineer calls and chairs the Tri-State Flow Diagram Conference. In addition to the Tri-State and Process, Project Engineers from the following departments MUST attend, other departments are optional: Control Systems Engineering Manager and/or Area Project Engineer Mechanical Piping- Piping Material Process Project Process Engineer forwards conference marked master to the Control Systems Design Supervisor.
17	1	Line Numbers	Piping Material	Project Piping Material Engineer forwards line numbers to the Control Systems Design Supervisor.
18	1	Instrument Numbers	Control Systems Engineering	Project Control Systems Engineer forwards instrument numbers to the Control Systems Design Supervisor.

FLOW DIAGRAM PROCEDURE
MECHANICAL/UTILITY SYSTEM FLOW DIAGRAM
TABLE 3-2 (CONT)

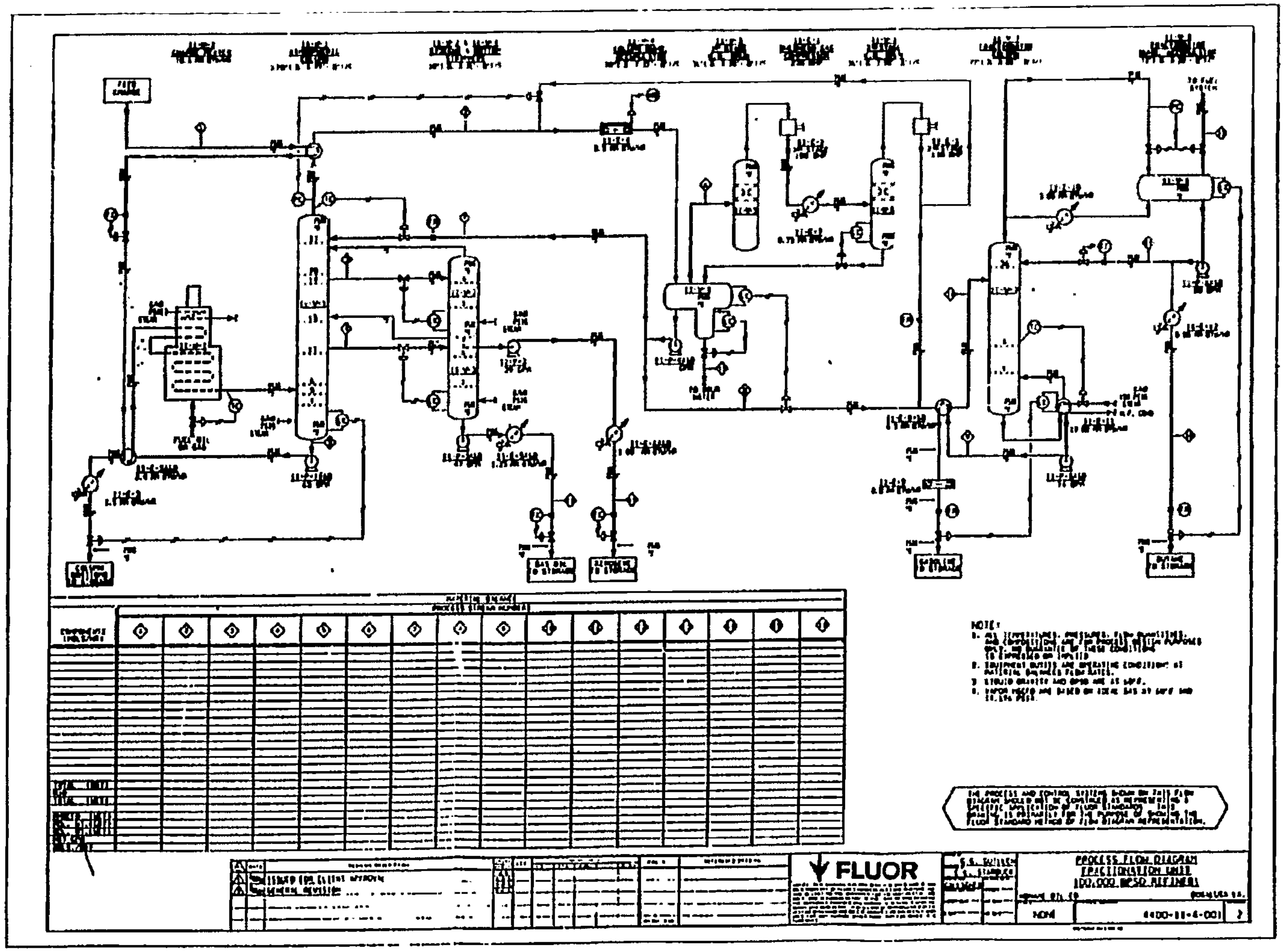
SEQUENCE	REVISION	ACTIVITY	RESPONSIBILITY	ACTIVITY DESCRIPTION
19	2	Fifth Revision and Issue "Client Approval Noted"	Control Systems Design	Revise original Obtain Fluor approval signatures—Process and Control Systems only.
			Process	Obtain Client signature.
			Control Systems Design	Issue AFC Revision 2, distribution to be in accordance with the Project distribution list.
		Establishing the "Project Master"	Piping	The Area or Unit Piping Supervisor designates his flow diagram prints as "Project Master" and places them on roll boards in his drafting area.
20	2	Project Master Update	All Engineering Departments	All Engineering Departments are responsible for keeping the "Project Master" Flow Diagram current with their latest developments of engineering and design data. The Area or Unit Piping Supervisor is responsible for the maintenance of the "Project Master" flow diagrams. The Project Control Systems Engineer is responsible for the revision of the "Project Master" original and the issuing of up-to-date prints. They also are responsible for consulting with the Area or Unit Piping Supervisor to establish the optimum time for revision and issue. They are also to notify all engineering departments of the scheduled revision and issue dates to assure updating of the "Project Master" before revision and issue. The Engineering departments are to indicate their compliance and agreement by "signing off" the "Project Master".
21	3	Revise Original and	Control Systems Design	Revise original in accordance with the marks indicated on the "Project Master." Obtain Fluor approval signature. Process and Control Systems only. Issue Revision 3, distribution to be in accordance with the Project distribution list.
22	4	Revise Original and Issue	All Engineering Departments	Repeat sequences 21 and 22 for subsequent issues.

PROCESS CRITERIA

3.2 Process Flow Diagram

The following Process Flow Diagram (Figure 3-1) gives an example of the format as well as the information needed for these drawings. The material balances can be on separate sheets of paper; however, if this option is chosen then the material balances must be typed.

Figure 3-1



FLUOR
PROCESS FLOW DIAGRAM
FRACTIONATION UNIT
100,000 BPSD REFINERY

PROCESS CRITERIA

3.3 Definition of Process Flow Diagram Revision Numbering

3.3.1 Phase I

a. See Table 3-1 for revision numbering.

b. The development for Phase 1 will be thru Revision 01.

3.3.2 Phase II

Phase II will carry the PFD's to completion and issued AFC.

3.4 Process Flow Diagram Checklist

3.4.1 GENERAL

The process flow diagram shows the basic process flow, and only the equipment, piping and instruments necessary for process clarity, the following process data is normally shown:

3.4.1.1 Temperature and pressure for each vessel and process line, including incoming and outgoing lines.

3.4.1.2 Steam pressure for reboilers (psig).

3.4.1.3 Cooling water type, with inlet temperature (°F).

3.4.1.4 Exchanger duty BTU/hr.

3.4.1.5 Fired heater duty BTU/hr.

3.4.1.6 Pump gpm (actual calculated - not design). Metering pumps (gph).

3.4.1.7 Packing height and size of packing for packed towers (ft).

3.4.1.8 Material Balance Table, (table may be omitted or shown separately at the discretion of the process engineer).

3.4.1.9 Equipment symbols are per section 3.11.

3.4.1.10 For equipment identification letters see Project Procedure Manual.

3.4.1.11 Duplicate pieces of equipment, i.e. spare pumps and heat exchangers with more than one shell, are not shown but are identified by item number only.

3.4.1.12 Temperature, pressure, flow rate, specific gravity, and destination source of all streams entering or leaving at the unit battery limit must be given.

It is important that these data pertain to the battery limit boundary or interconnecting flange, and not to a more remote point.

3.4.2 VESSELS

3.4.2.1 Trays are numbered from bottom to top. The only trays shown are those at top and bottom, and those which locate process lines and/or instruments.

3.4.2.2 Catalyst beds, packed sections, demister sections, etc., are shown, with height and size of packing shown near the vessel (ft).

3.4.2.3 Operating pressure and temperature for each vessel and process line (psig and °F) must be given.

3.4.2.4 In the case of towers, or other instances where sufficient variations exist, the temperature and/or pressure for both the top and the bottom must be given.

3.4.2.5 At the top of the flow diagram, above each vessel, the following is listed:

a. Vessel Item Number (this number will also appear in or adjacent to the vessel).

b. Title.

c. Size (inside diameter in inches and tangent-to-tangent length in feet and inches.

3.4.3 FIRED HEATERS

3.4.3.1 Heating medium is shown and identified.

3.4.3.2 Process piping is shown for one pass only.

3.4.3.3 At the top of the flow diagram, above each heater, the following is listed:

a. Heater Item Number.

b. Title.

c. Duty - BTU/hr.

3.4.4 EXCHANGERS, CONDENSERS, COOLERS AND REBOILERS

3.4.4.1 Adjacent to each exchanger, cooler, condenser or reboiler the following is listed:

a. Equipment Item Number.

b. Duty - BTU/hr.

3.4.4.2 On shell and tube exchangers the stream through the tube is identified by a dashed line.

3.4.5 PUMPS

3.4.5.1 Below each pump the following is listed:

a. Pump Item Number.

b. gph or gpm (actual or calculated value)

3.4.6 COMPRESSORS

3.4.6.1 The compressor symbol is repeated for each stage of a multistage compressor.

3.4.6.2 Below each compressor the following is listed:

a. Compressor Item Number.

b. Stage (when required).

3.4.7 INSTRUMENTATION

Only the process control instrumentation needed for process clarity is shown.

3.4.8 MISCELLANEOUS

3.4.8.1 Material Balance

a. Process lines are tagged with a number referencing the line to the Material Balance at the bottom of the flow diagram (omit when no material balance is required). Utility lines are not identified by number.

b. The Material Balance is a tabulated breakdown of the various components of each process steam shown on the flow diagram. See the example for a Process Flow Diagram for the recommended material balance format.

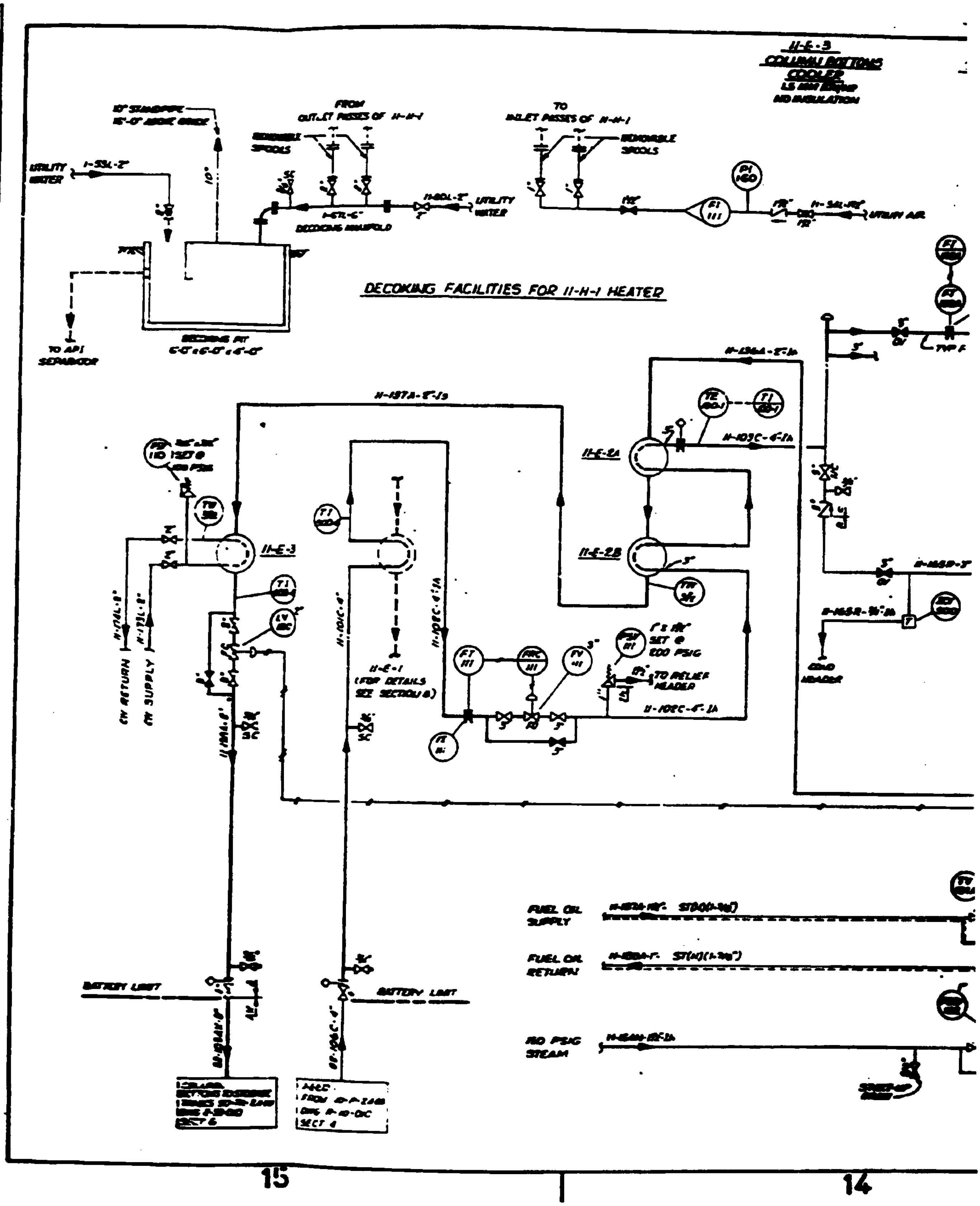
c. The material balances are to be tabulated on a stream hour basis showing the expected flow rates.

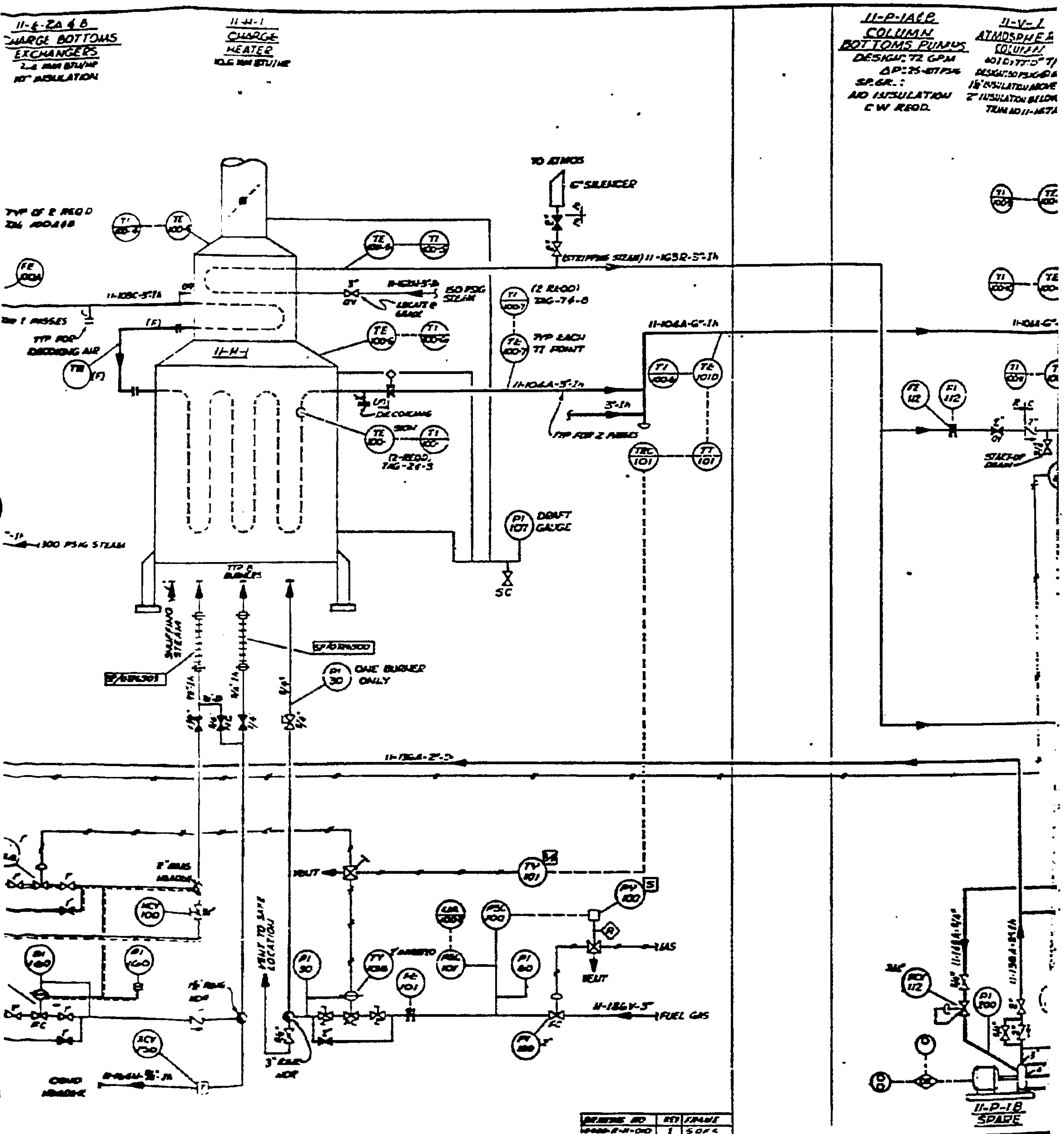
3.4.9 TITLE BLOCK

A sample title block is included in the Engineering Section of the Project Procedure Manual.

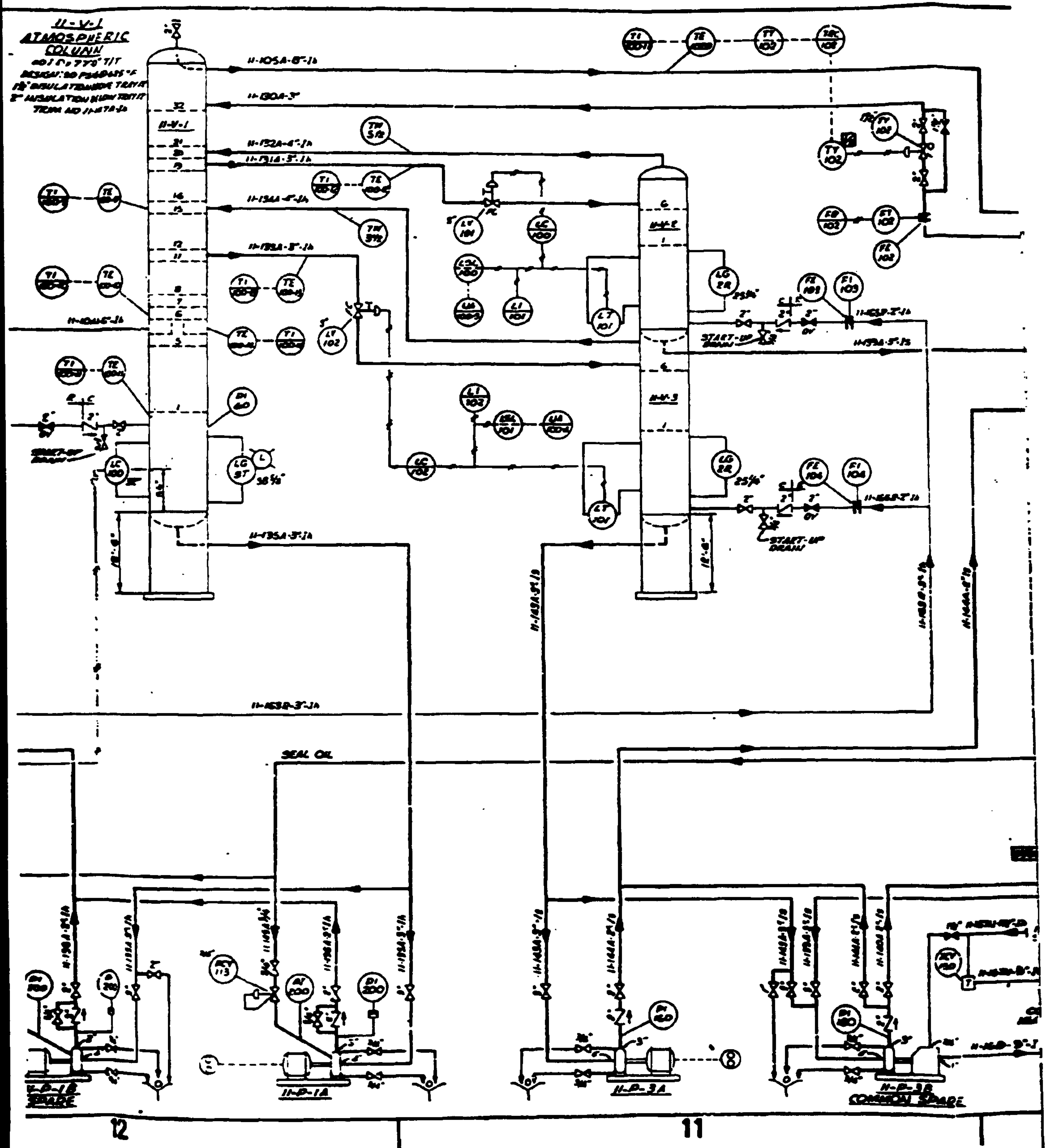
3.5 Mechanical Flow Diagram

The following example for a Mechanical Flow Diagram (Figure 3-2) shows the format and the data required on all final Mechanical Flow Diagrams for the Tri-State Synfuels Project. Mechanical Flow Diagrams will be at various stages of development at the completion of Phase I work. Some of the MFD's for process units may be nearing completion while others may be in a very preliminary stage. The objective of Phase I is to advance the engineering work for the overall project in a logical sequence, developing the MFD's to the maximum extent possible within the budget constraints.

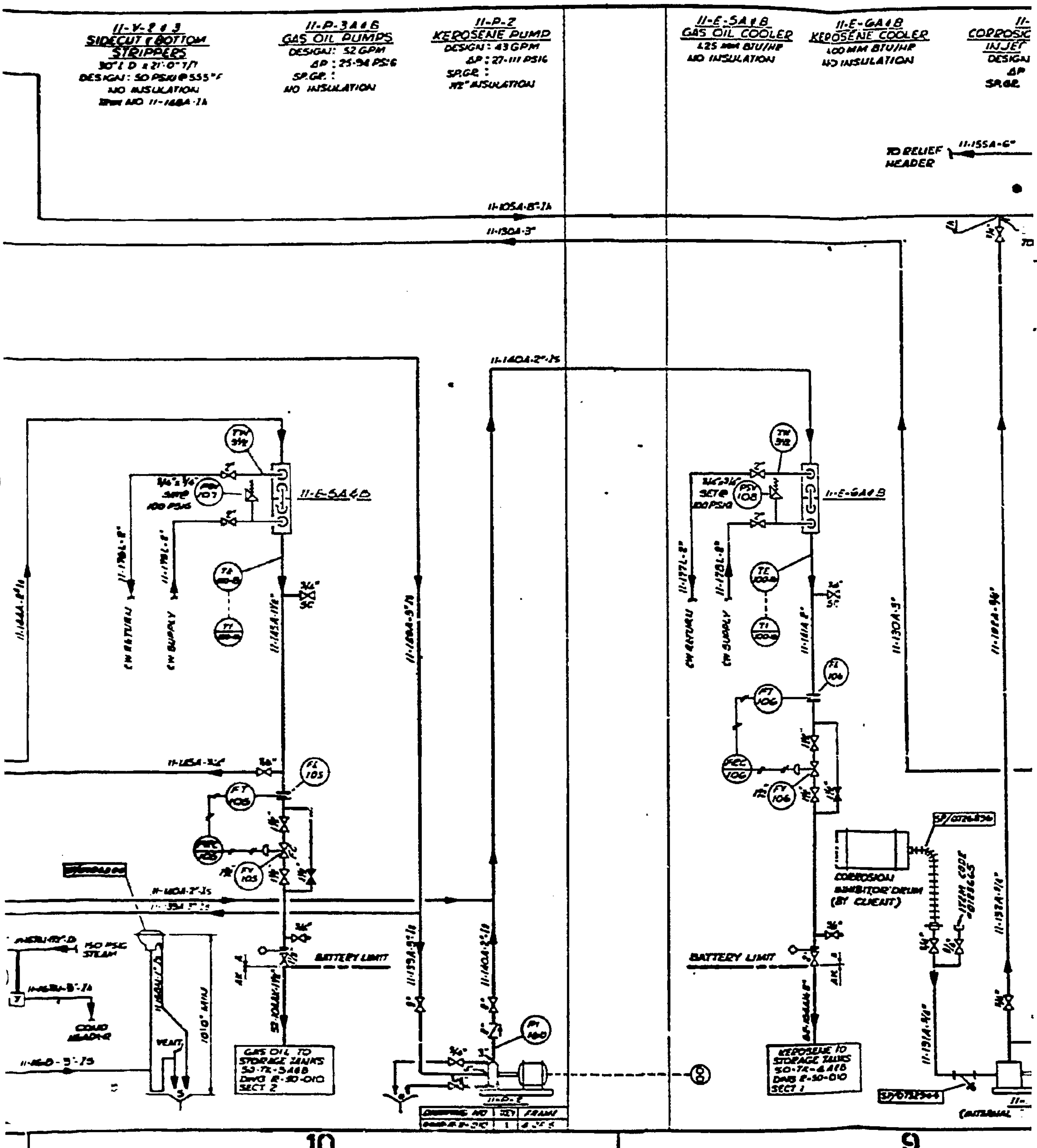

11-E-3
COLUMN BOTTOMS
COOLER
DECOKING FACILITIES FOR 11-H-1 HEATER
FROM
OUTLET PASSES OF 11-H-1
TO
INLET PASSES OF 11-H-1
REMOVABLE SPOOLS
UTILITY WATER
UTILITY AIR
DECOKING MANIFOLD
TO API SEPARATOR
11-E-2A
11-E-2B
11-E-1
CW RETURN
CW SUPPLY
TO RELIEF HEADER
COND HEADER
BATTERY LIMIT
FUEL OIL SUPPLY
FUEL OIL RETURN
STEAM
15
14



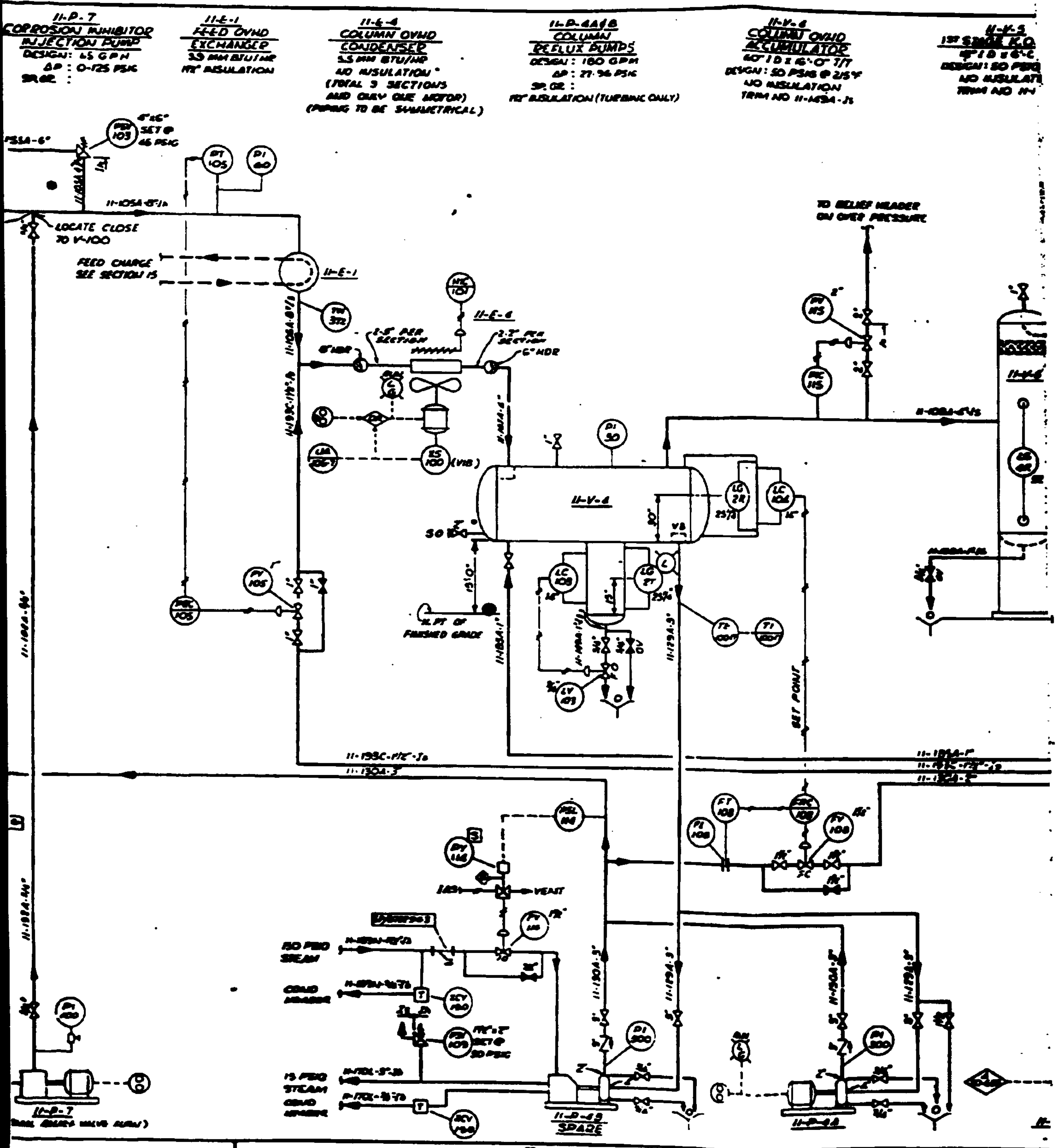
11-E-2A & B
CHARGE BOTTOMS EXCHANGERS
11-H-1
CHARGE HEATER
11-P-1A&B
COLUMN BOTTOMS PUMPS
DESIGN: 72 GPM
NO INSULATION
CW REQD.
11-V-1
ATMOSPHERIC COLUMN
TO ATMOS
6" SILENCER
150 PSIG STEAM
DECOKING
DRAFT GAUGE
SC
SNUFFING STEAM
ONE BURNER ONLY
300 PSIG STEAM
VENT
FUEL GAS
VENT TO SAFE LOCATION
11-P-1B
SPARE



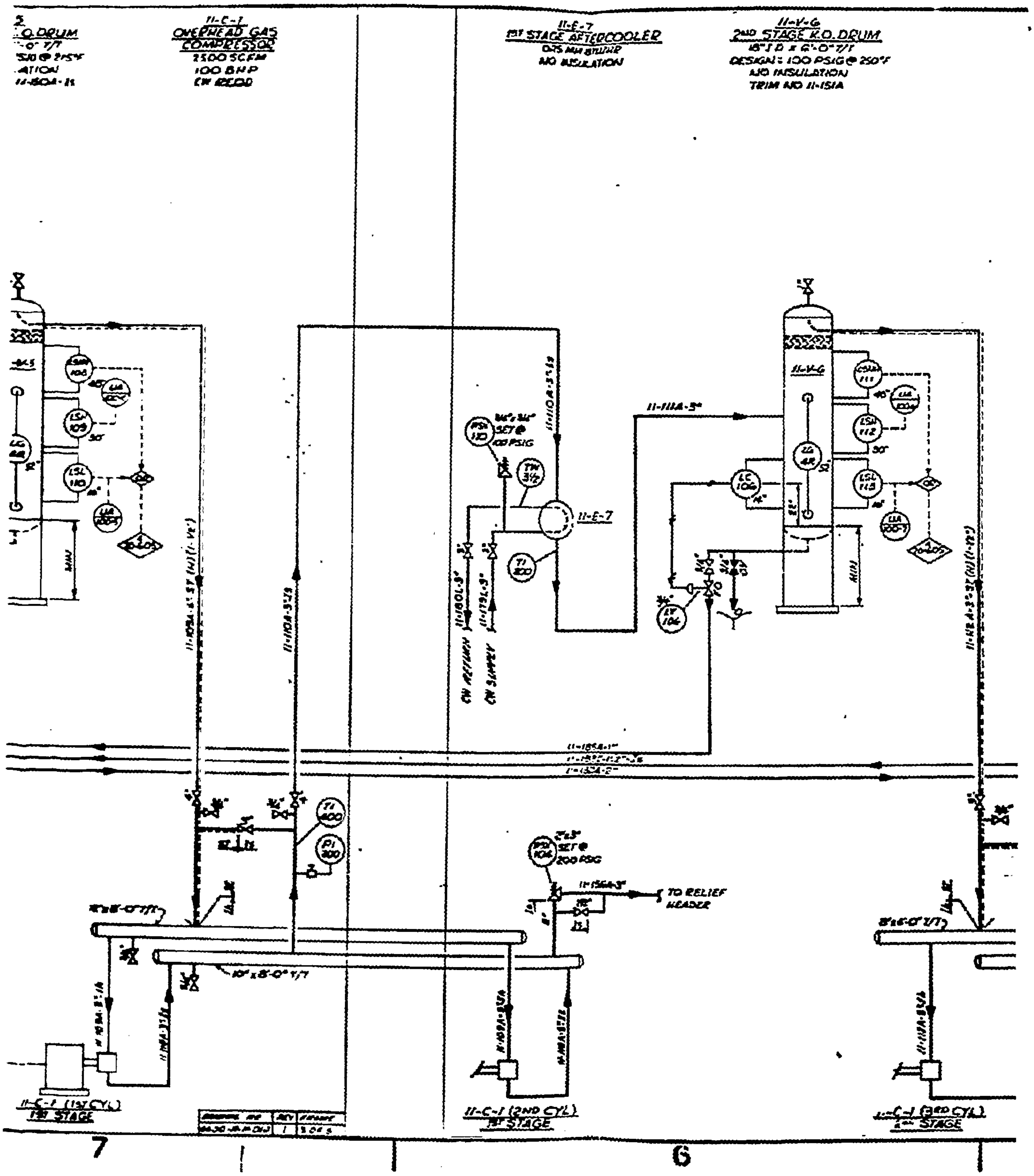
11-V-1
ATMOSPHERIC
COLUMN
11-V-1
11-V-2
11-V-3
START-UP
DRAIN
SEAL OIL
11-P-1B
SPARE
11-P-1A
11-P-3A
11-P-3B
COMMON SPARE
12
11



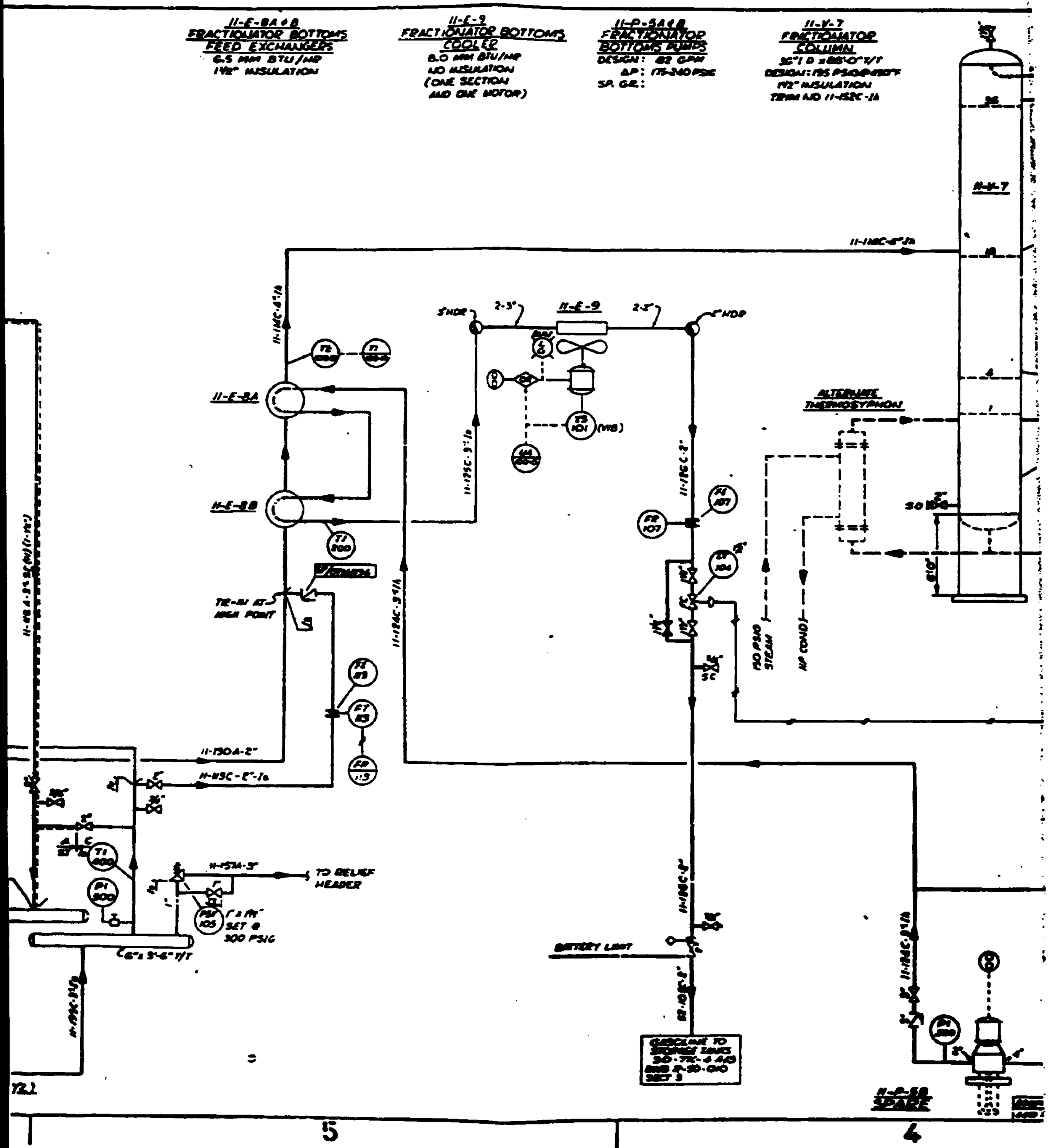
11-V-2 & 3
SIDECUT & BOTTOM STRIPPERS
DESIGN : 50 PSIG @ 555°F
NO INSULATION
11-P-3A & B
GAS OIL PUMPS
DESIGN : 52 GPM
ΔP : 25-94 PSIG
SP.GR. :
NO INSULATION
11-P-2
KEROSENE PUMP
DESIGN : 43 GPM
ΔP : 27-111 PSIG
SP.GR. :
NO INSULATION
11-E-5A & B
GAS OIL COOLER
NO INSULATION
11-E-6A & B
KEROSENE COOLER
NO INSULATION
CORROSION INHIBITOR INJECTION
DESIGN
ΔP
SP.GR.
TO RELIEF HEADER
11-155A-6"
11-105A-8"
11-130A-3"
11-140A-2"
11-E-5A & B
11-E-6A & B
CW RETURN
CW SUPPLY
11-130A-3"
CORROSION INHIBITOR DRUM (BY CLIENT)
BATTERY LIMIT
BATTERY LIMIT
150 PSIG STEAM
COND HEADER
VENT
GAS OIL TO STORAGE TANKS
KEROSENE TO STORAGE TANKS
11-P-2
10
9

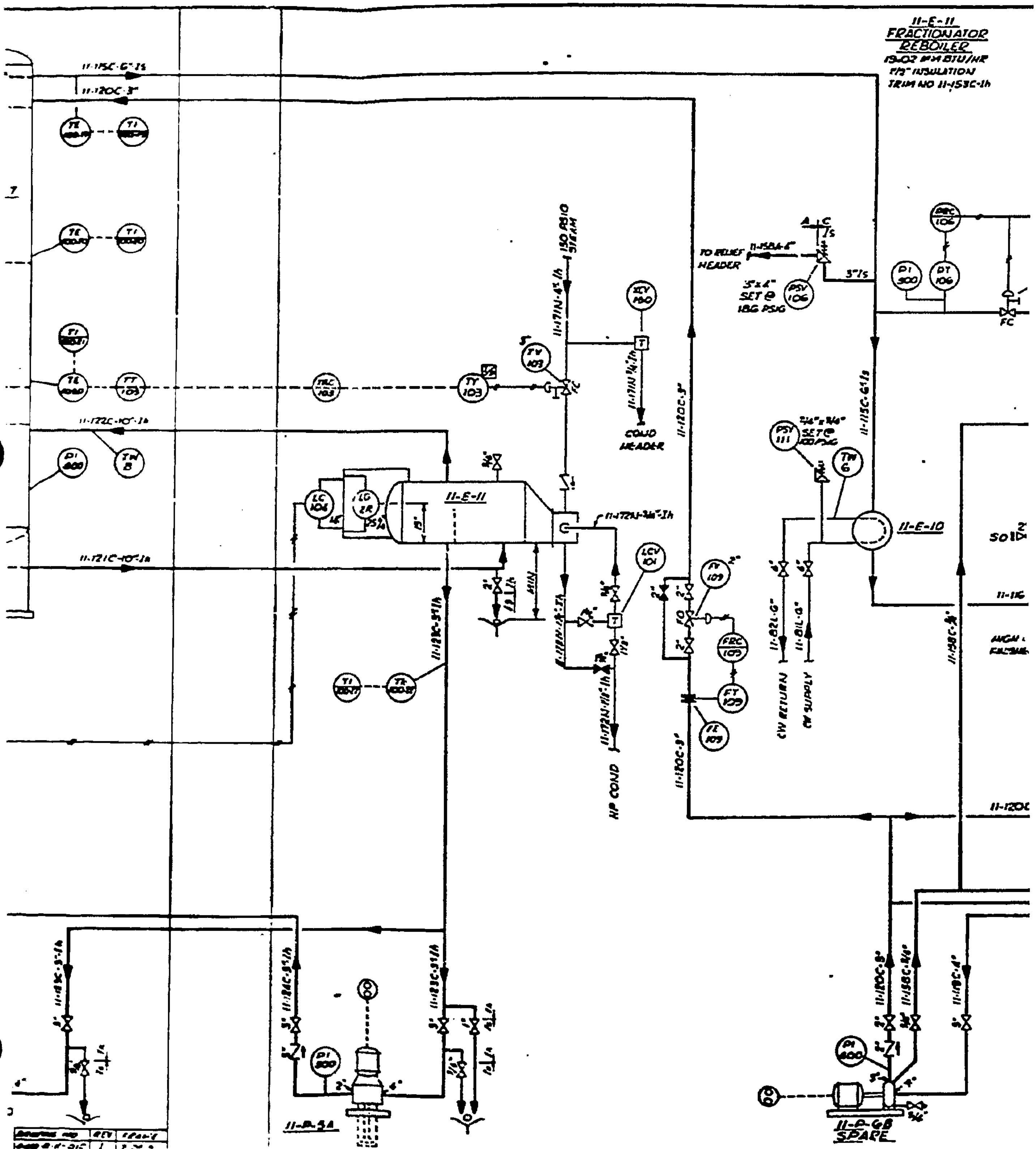


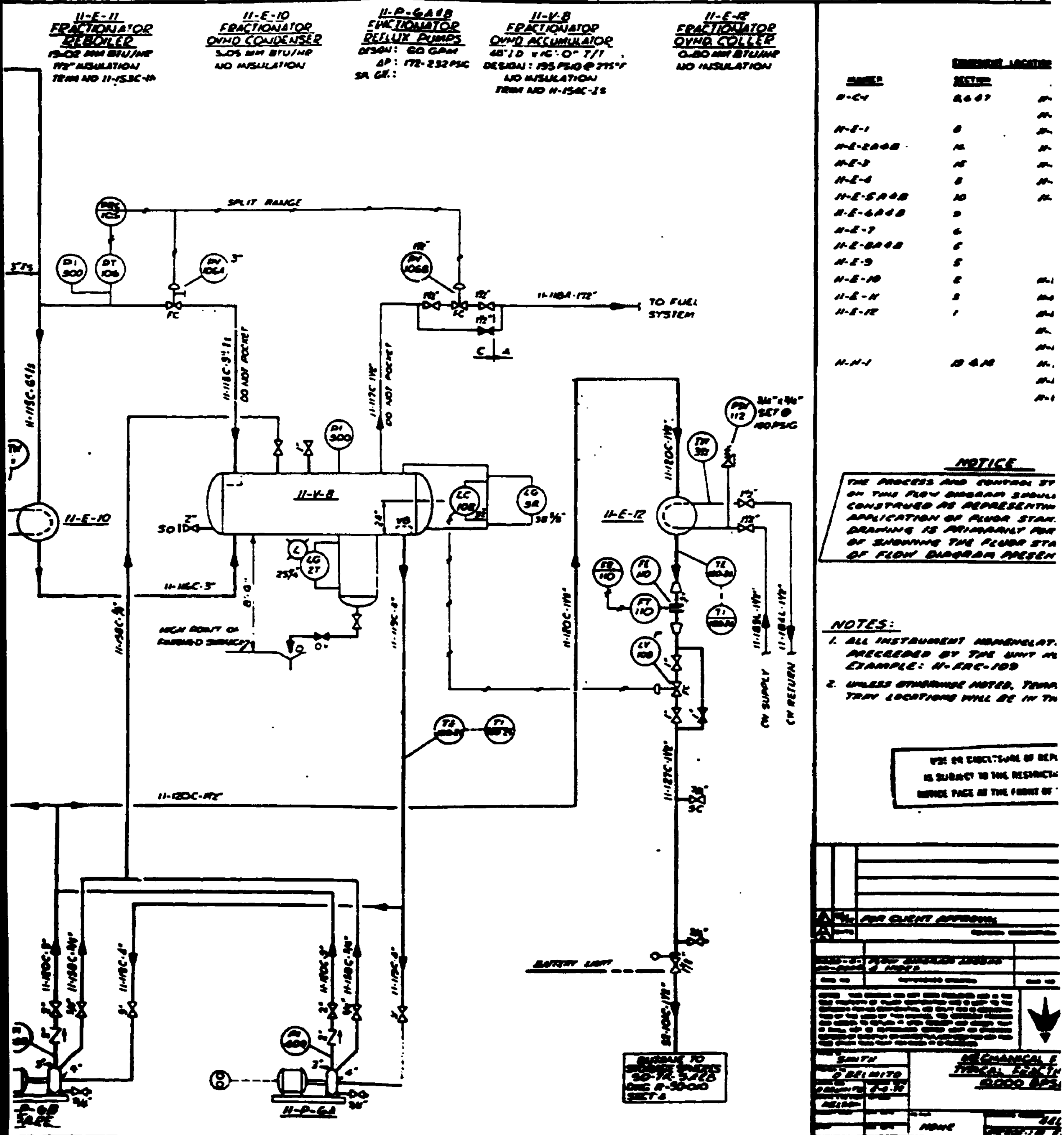
11-P-7
CORROSION INHIBITOR INJECTION PUMP
11-E-1
FEED OVHD EXCHANGER
11-E-4
COLUMN OVHD CONDENSER
11-P-4A&B
COLUMN REFLUX PUMPS
11-V-4
COLUMN OVHD ACCUMULATOR
LOCATE CLOSE TO V-100
FEED CHARGE SEE SECTION 15
TO RELIEF HEADER ON OVER PRESSURE
11-V-4
SET POINT
VENT
150 PSIG STEAM
COND HEADER
15 PSIG STEAM
11-P-4B SPARE
11-P-4A



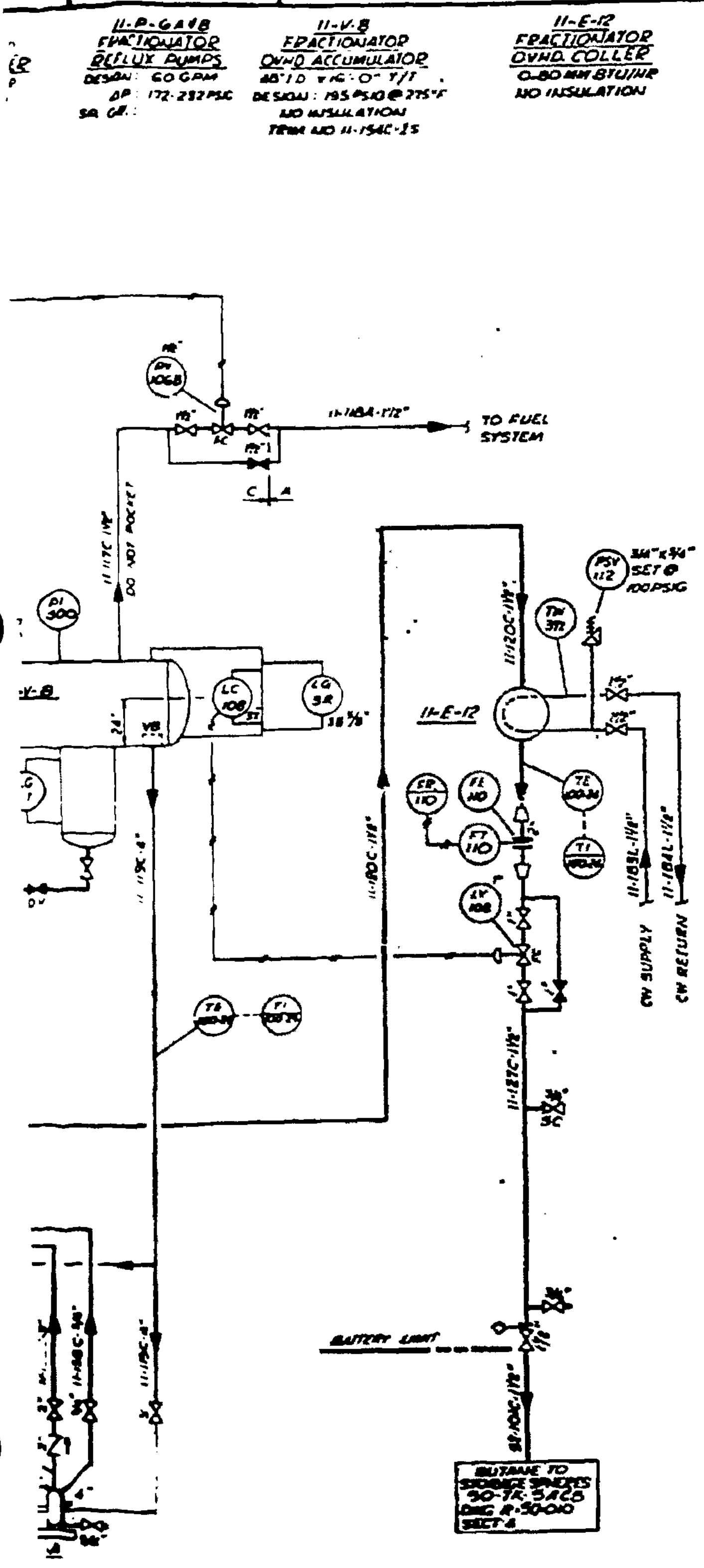
11-C-1
OVERHEAD GAS
COMPRESSOR
2500 SCFM
100 BHP
11-E-7
1ST STAGE AFTERCOOLER
NO INSULATION
11-V-6
2ND STAGE K.O. DRUM
DESIGN: 100 PSIG @ 250°F
NO INSULATION
TRIM NO 11-151A
11-V-6
11-111A-3"
11-E-7
SET @
100 PSIG
CW RETURN
CW SUPPLY
SET @
200 PSIG
11-156A-3"
TO RELIEF
HEADER
10" x 8'-0" T/T
11-C-1 (1ST CYL)
1ST STAGE
11-C-1 (2ND CYL)
1ST STAGE
11-C-1 (3RD CYL)
2ND STAGE
7
6


11-E-8A & B
FRACTIONATOR BOTTOMS FEED EXCHANGERS
6.5 MM BTU/HR
1½" INSULATION
11-E-9
FRACTIONATOR BOTTOMS COOLER
8.0 MM BTU/HR
NO INSULATION
(ONE SECTION AND ONE MOTOR)
11-P-5A & B
FRACTIONATOR BOTTOMS PUMPS
DESIGN: 82 GPM
ΔP: 175-240 PSIG
SP. GR.:
11-V-7
FRACTIONATOR COLUMN
11-E-8A
11-E-8B
11-E-9
ALTERNATE THERMOSYPHON
150 PSIG STEAM
HP COND.
TIE-IN AT HIGH POINT
TO RELIEF HEADER
SET @ 300 PSIG
BATTERY LIMIT
GASOLINE TO STORAGE TANKS
11-P-5B SPARE
5
4


11-E-11
FRACTIONATOR
REBOILER
TO RELIEF
HEADER
150 PSIG
STEAM
COND
HEADER
11-E-11
LC
104
LG
2R
LCV
101
FRC
109
FT
109
FE
109
PSV
106
PSV
111
PI
300
PT
106
TW
6
TW
8
11-E-10
CW RETURN
CW SUPPLY
HP COND
MIN
FO
FC
11-P-5A
11-P-6B
SPARE



11-E-11
FRACTIONATOR REBOILER
NO INSULATION
11-E-10
FRACTIONATOR OVHD CONDENSER
NO INSULATION
11-P-6A&B
FRACTIONATOR REFLUX PUMPS
DESIGN: 60 GPM
11-V-8
FRACTIONATOR OVHD ACCUMULATOR
NO INSULATION
11-E-12
FRACTIONATOR OVHD COLLER
NO INSULATION
SPLIT RANGE
TO FUEL SYSTEM
DO NOT POCKET
11-V-8
11-E-10
11-E-12
NOTICE
NOTES:
CW SUPPLY
CW RETURN
BATTERY LIMIT
11-P-6A
NONE



EQUIPMENT LOCATION INDEX

NUMBER	SECTION	NUMBER	SECTION
11-C-1	[illegible]	11-P-1A&B	12
		11-P-2	10
11-E-1	8	11-P-3A&B	11
11-E-2A&B	14	11-P-4A&B	8
11-E-3	15	11-P-5A&B	3&4
11-E-4	8	11-P-6A&B	2
11-E-5A&B	10	11-P-7	3
11-E-6A&B	3		
11-E-7	6		
11-E-8A&B	6		
11-E-9	5		
11-E-10	2	11-V-1	12
11-E-11	3	11-V-2	11
11-E-12	1	11-V-3	11
		11-V-4	8
		11-V-5	7
11-H-1	13 & 14	11-V-6	6
		11-V-7	4
		11-V-8	2

NOTICE

THE PROCESS AND CONTROL SYSTEMS SHOWN ON THIS FLOW DIAGRAM SHOULD NOT BE CONSTRUED AS REPRESENTING A SPECIFIC APPLICATION OF FLUOR STANDARDS. THIS DRAWING IS PRIMARILY FOR THE PURPOSE OF SHOWING THE FLUOR STANDARD METHOD OF FLOW DIAGRAM PRESENTATION.

NOTES:

1. ALL INSTRUMENT NOMENCLATURE WILL BE PRECEEDED BY THE UNIT NUMBER EXAMPLE: 11-FRC-109
2. UNLESS OTHERWISE NOTED, TEMPERATURE POINTS AT TRAY LOCATIONS WILL BE IN THE LIQUID PHASE.

USE OR DISCLOSURE OF REPORT DATA IS SUBJECT TO THE RESTRICTION ON THE NOTICE PAGE AT THE FRONT OF THIS REPORT

FOR CLIENT APPROVAL

FLUOR

MECHANICAL FLOW DIAGRAM
TYPICAL FRACTIONATION UNIT
10,000 BPSD REFINERY

SMITH
O'BELMITO

NONE

4400-R-11-010

PROCESS CRITERIA

3.6 Definition of Mechanical Flow Diagram Revision Numbering

3.6.1 Phase I

a. See Table 3-2 for revision numbering.

b. Development for Phase 1 will be thru Revision 01.

3.6.2 Phase II

Phase II will carry the MFD's to completion and issue AFC.

3.7 Mechanical Flow Diagram Checklist

3.7.1 GENERAL

The mechanical flow diagram shows the equipment, instruments, piping and any miscellaneous items, with corresponding data required for the mechanical design of a particular unit.

3.7.1.1 Equipment is laid out to conform with process flow.

3.7.1.2 Equipment symbols are per Section 3.11.

3.7.1.3 For equipment identification letters see the Project Procedure Manual.

3.7.1.4 When a group of major pieces of equipment has identical process and utility piping and instrumentation, only one of the groups, with all piping and instrumentation is shown. The others of the group are indicated by individual blocks and are identified, but only those portions of piping necessary for line identification are shown.

3.7.2 VESSELS

3.7.2.1 Top and bottom trays, and only those trays necessary to locate feed and product lines, instrumentation, sample connections, etc., are shown. Catalyst beds, packing, demisters, chimney trays, etc., are also shown.

3.7.2.2 At the top of the flow diagram, above each vessel, the following is listed:

a. Vessel Item Number (this number will also appear in or adjacent to the vessel).

b. Title.

c. Size (inside diameter in inches and tangent-to-tangent length in feet and inches).

d. Design Pressure and Temperature. (psig and °F)

e. Insulation (thickness or the word "No").

f. Line Number of vessel trim (this applies to LG & LC connections, vents, S.C., etc.).

3.7.3 FIRED HEATERS

3.7.3.1 For burner piping details at heaters see Section 11.7.

3.7.3.2 At the top of the flow diagram above each heater, the following is listed:

a. Heater Item Number. (This number will also appear in or adjacent to the heater.)

b. Title.

c. Duty - BTU/hr.

3.7.4 EXCHANGERS, CONDENSERS. COOLERS AND REBOILERS

At the top of the flow diagram above each exchanger, cooler, condenser or reboiler the following is listed:

a. Equipment Item Number. (This number also appears in or adjacent to the item.)

b. Title.

c. Duty - BTU/hr.

d. Insulation (thickness or the word "No").

3.7.5 PUMPS

3.7.5.1 At the top of the flow diagram, above each operating pump, the following is listed:

a. Pump Item Number. (This number also appears below the pump.)

b. Title.

c. gph or gpm (design rate).

d. Differential Pressure, psi.

e. Specific gravity of pumped fluid at pumping temperature.

f. Insulation (thickness or the word "No").

g. Miscellaneous auxiliary piping (C.W., flushings oil, seal oil, etc.).

3.7.5.2 When a pump is spared, the data is listed for the operating pump at the top of the flow diagram, and the spare is identified only by number and the word "Spare" below the pump. The operating pump and the spare have the same number but with suffixes "A" and "B".

3.7.6 COMPRESSORS

3.7.6.1 At the top of the flow diagram, directly above each compressor, the following is listed:

a. Compressor Item Number (cylinder number). (This number also appears below the Compressor.)

b. Compressor Title (stage).

c. SCFH.

d. HP.

3.7.6.2 Cylinder and stage numbers are shown only for multistage compressors. All compressor data appears over the first stage only. For subsequent stages SCFH and HP are omitted.

3.7.7 INSTRUMENTATION

3.7.7.1 Instrumentation symbols are in accordance with ISA Standards, with minor modifications as indicated in Fluor Standards.

3.7.7.2 Control valve sizes shall be shown. Block and bypass valve sizes at control valve stations shall be shown. Sizing will be determined by the Control Systems Engineer unless contract requirements dictate otherwise.

3.7.8 PIPING

3.7.8.1 Layout

a. The origin and terminus of each feed and product line entering or leaving the flow diagram is identified by a box which shows the descriptive title of the line, and the drawing number and section number of any reference drawing.

b. High point vents and low point drains are shown only when they connect to a closed system, or are required for process reasons.

Pertinent information regarding a line such as "Do not pocket or slope", etc., is noted adjacent to the line.

c. Utility lines originate and terminate adjacent to the equipment involved. Only the length of line necessary for valving, instrumentation and line numbering is shown. Utility line origin and terminus is indicated by descriptive title only. Main utility headers are not shown on the mechanical flow diagram; they are shown on the utility System Flow Diagram.

d. Compressor utility piping is shown only when minor in scope; otherwise it is shown on a compressor auxiliary flow diagram.

e. All valves shown on the flow diagram shall have their size indicated by the valve.

3.7.8.2 Reduction in Line Size

Reduction in line size is indicated only by line size designation. Reducer symbols are shown only when required for clarity.

3.7.8.3 Line Numbers

Each process and each utility line is identified by a line number.

3.7.8.4 Pipe Wall Thickness

Calculated wall thicknesses not already prespecified in the individual Line Classes will be shown.

3.7.8.5 Corrosion Allowances

Corrosion allowances other than the nominal or adjusted allowances indicated in the individual Line Classes will also be shown.

3.7.8.6 Piping Out of Spec Items

Piping components not identified by Instrument or Mechanical Equipment Numbers, etc., and not covered by the Piping Material Specification, are identified by assigning an Item Code Number for identification symbol. See Section 3.11.

3.7.9 MISCELLANEOUS

3.7.9.1 Equipment Location Index - Upper right-hand area of the flow diagram. All equipment is listed by equipment number, alphabetically and numerically, and referenced to the number of the drawing section in which it appears.

3.7.9.2 Legend - For Flow Diagram Legend and Index see Section 3.11.

3.7.9.3 Title Block - In accordance with contract requirements.

3.7.9.4 Drawing Size - The flow diagram is usually roll size, 24" or 30" high (cut size) with length generally limited to 15'. If greater length is required and process layout permits, two flow diagrams are made rather than one. Process conditions not permitting, the flow diagram is made to required length. For smaller diagrams, a 4 size drawing may be used.

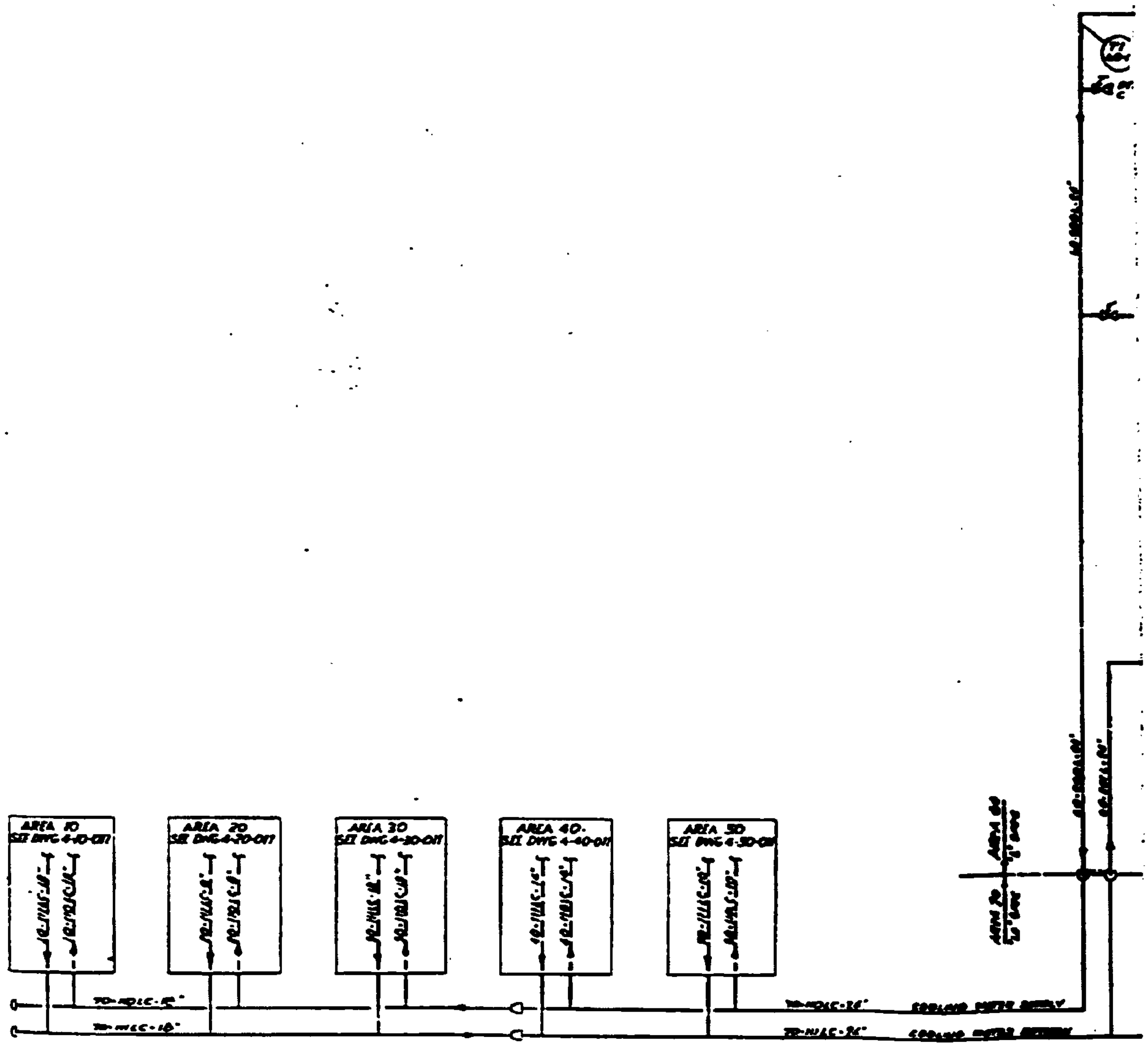
3.7.9.5 Sections - The flow diagram is divided horizontally into 12" sections. Beginning at the right-hand trim line, the sections are numbered consecutively in the lower margin "1," "2," "3," etc., from right to left.

3.7.9.6 Microfilming - When the job procedure calls for the drawings to be microfilmed, refer to job procedure instructions.

3.7.9.7 Equipment, instruments or piping, which are traced or jacketed, are so indicated.

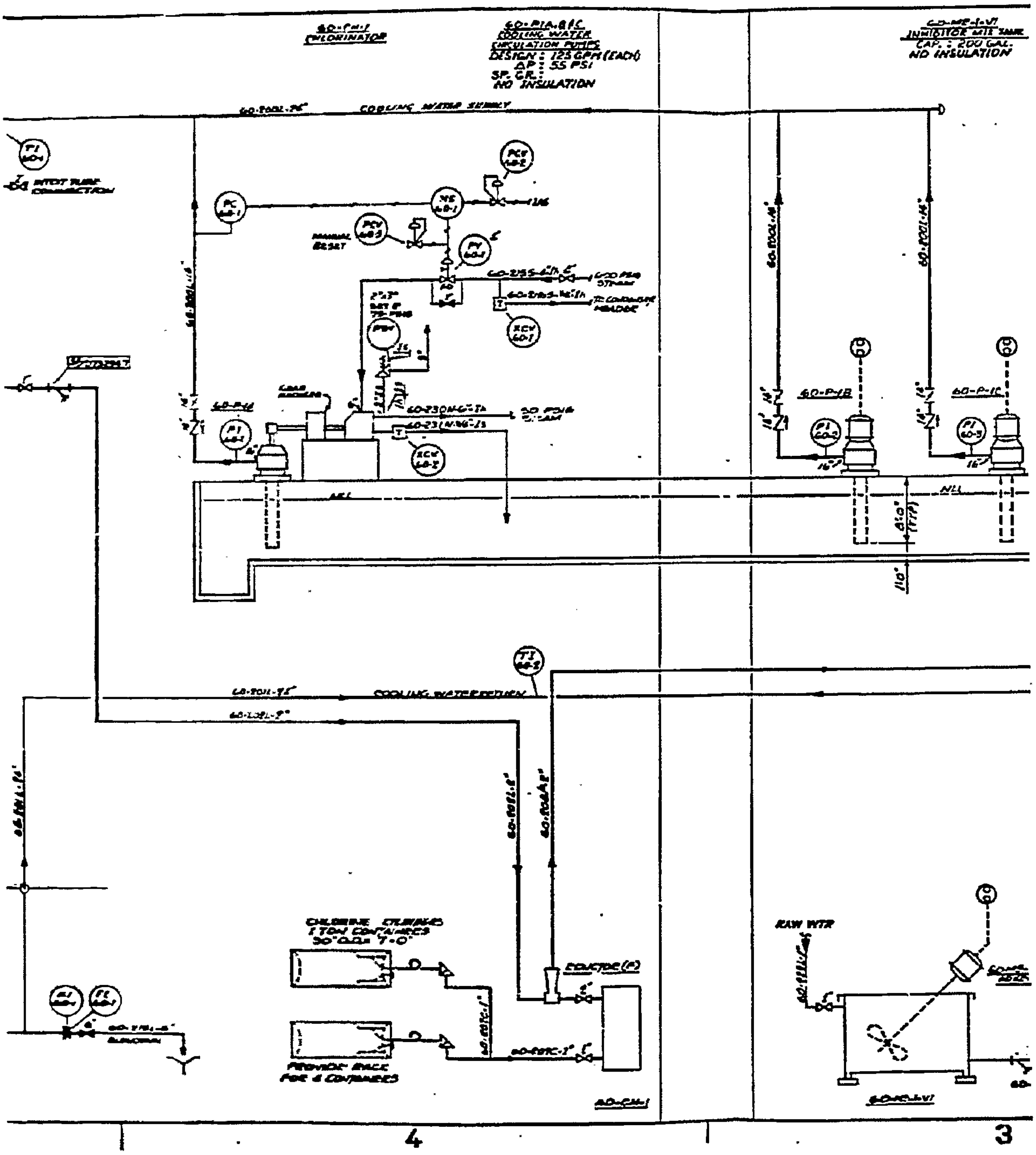
3.8 Utility System Flow Diagram

Utility and Off-site System Flow Diagrams (Figure 3-3) use the same revision numbering as the Mechanical Flow Diagrams.



6

5

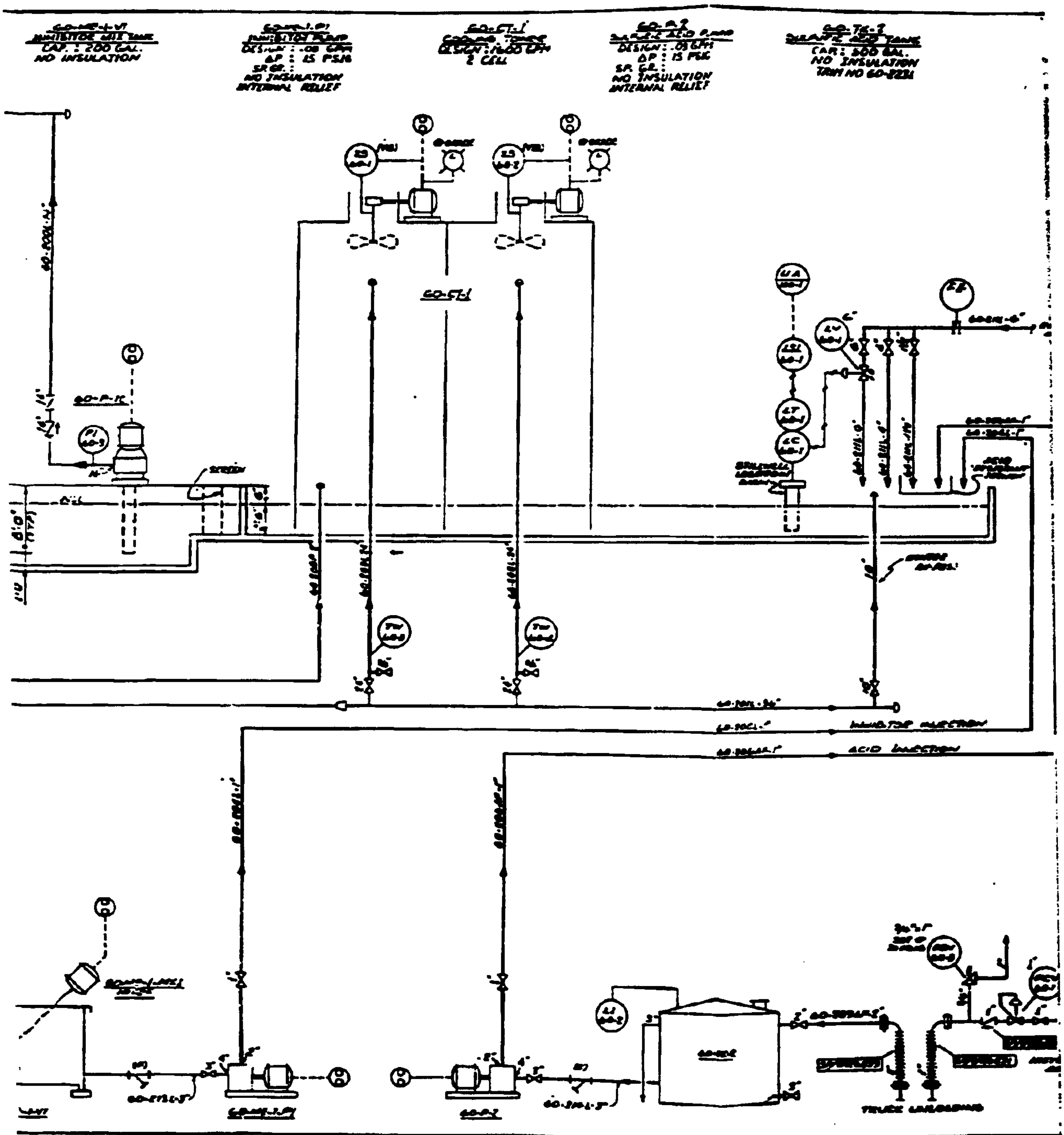


60-PM-1 CHLORINATOR
60-P1A,B&C COOLING WATER CIRCULATION PUMPS
DESIGN: 125 GPM (EACH)
ΔP: 55 PSI
SP. GR.:
NO INSULATION
INHIBITOR MIX TANK
CAP.: 200 GAL.
NO INSULATION
COOLING WATER SUPPLY
COOLING WATER RETURN
MANUAL RESET
NLL
RAW WTR
CHLORINE CYLINDERS
1 TON CONTAINERS
PROVIDE RACK FOR 6 CONTAINERS
EDUCTOR
60-CM-1
4
3

FLUOR

ENGINEERING STANDARDS

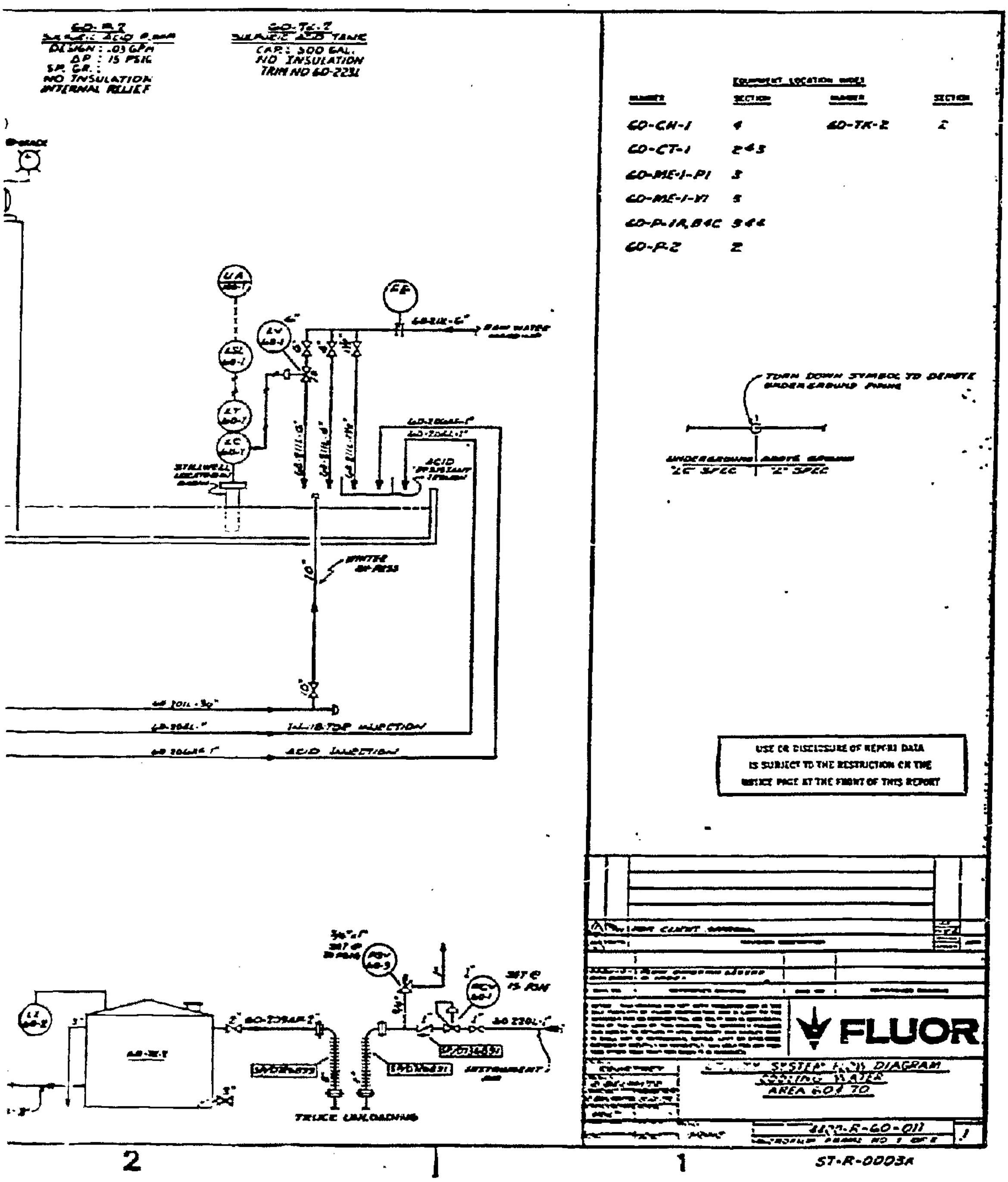
UT.



3

2

Figure 3-3


USE OR DISCLOSURE OF REPORT DATA IS SUBJECT TO THE RESTRICTION ON THE NOTICE PAGE AT THE FRONT OF THIS REPORT
FLUOR
TRUCK UNLOADING
ACID INJECTION
2
1
ST-R-0003A

PROCESS CRITERIA

3.9 Utility System Flow Diagram Description

3.9.1 General

The following is a description of a typical utility system flow diagram for a contract. Each flow diagram will consist of three sections: first, the mechanical elements needed to process the commodity; second, the pipeline network needed to convey the commodity to and/or from individual Process Areas; and third, the headers, subheaders, and pipelines needed within a Process Area to carry the utility commodity to or away from individual points of use or generation.

3.9.2 Mechanical Section

The mechanical section of the utility system flow diagram will show all equipment, instruments, controls, and specialty items in accordance with Section 3.5. This section will occupy the right hand side of the completed diagram. Main headers (supply and/or return, if required) will exit from the left side of this mechanical section. The header(s) will be clearly marked to define the extent existing within the primary utility processing area.

3.9.3 Distribution Section

The distribution section of the utility system flow diagram will show the main header(s) and branch lines which interconnect the battery limits of the primary processing area to the battery limits of each of the user or generator process areas. The branch line takeoff to individual areas will be shown in correct sequences. All equipment, controls, instruments, and valves which are a part of the headers or branch lines will be shown in the area where actually located.

3.9.4 Process Area Distribution Section

The process area distribution section of the utility system flow diagram will show, within each process area, the headers and connection lines to all equipment, utility stations, and other miscellaneous locations requiring a particular commodity. Takeoff from main headers will be shown in correct sequence but not in geographical plot. Valves, controls, and specialty items relating to the header system will be shown with this drawing. A pig-tail type connection will indicate a connection to be found on the related mechanical flow sheet with that piece of equipment.

PROCESS CRITERIA

3.10 Equipment Identification

Equipment identification letters are included in the Engineering Section of the Project Procedure Manual.

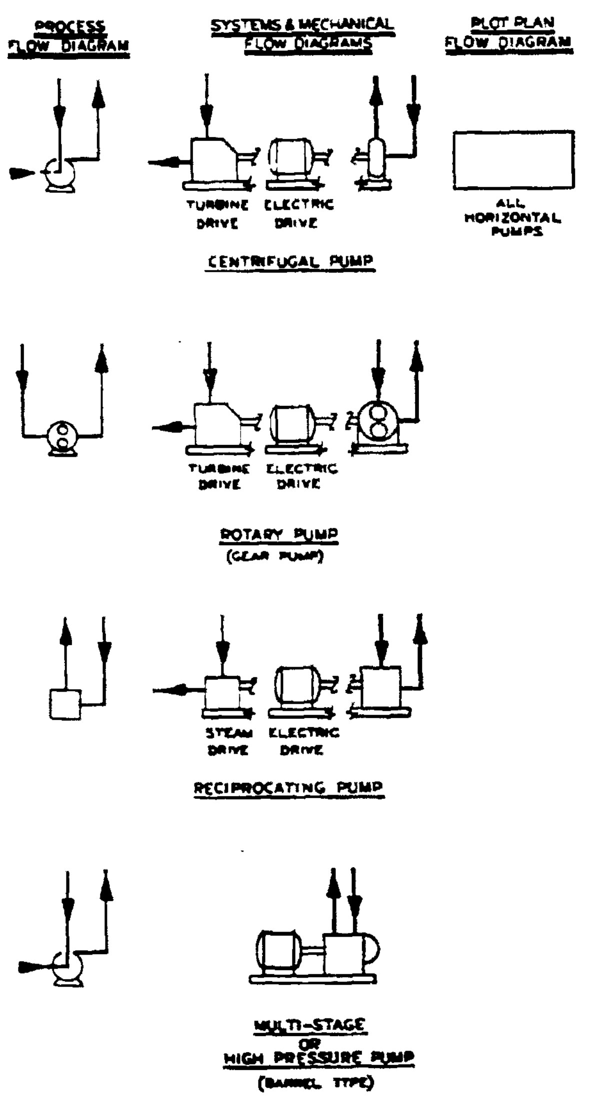
PROCESS CRITERIA

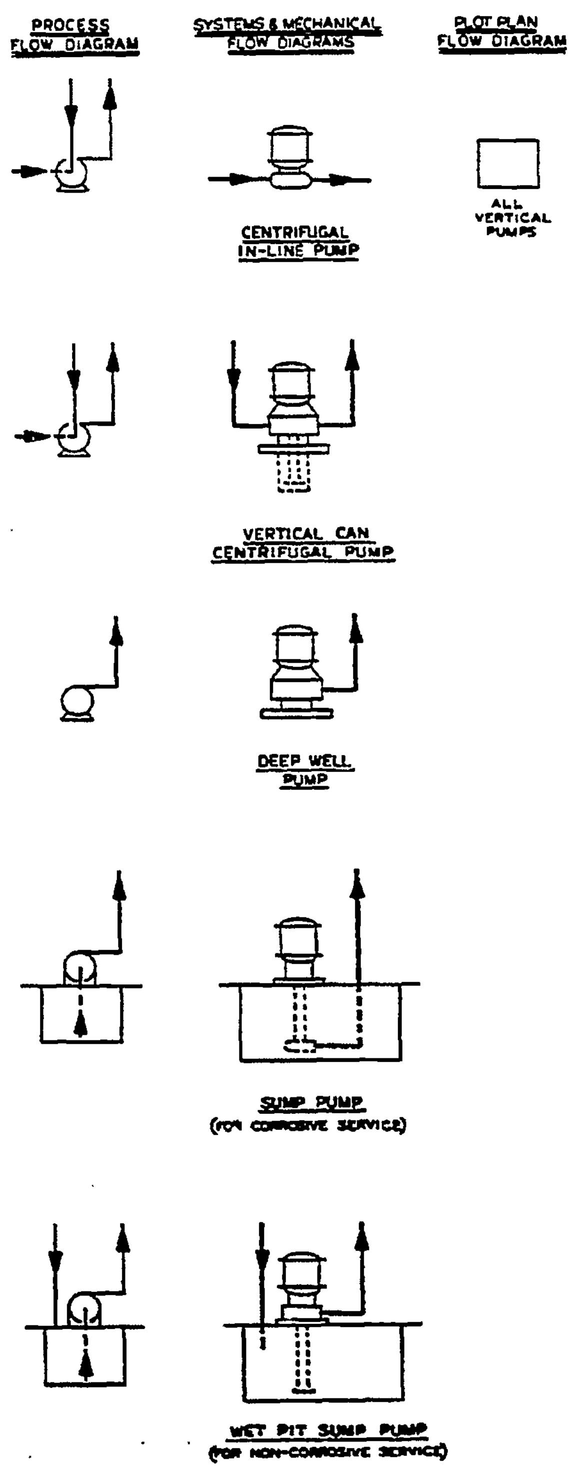
3.11 Flow Diagram Symbols

FLUOR
ENGINEERING STANDARDS

FLOW DIAGRAM SYMBOLS
PUMPS

NUMBER ST-1-0010
PAGE
DATE 7-77

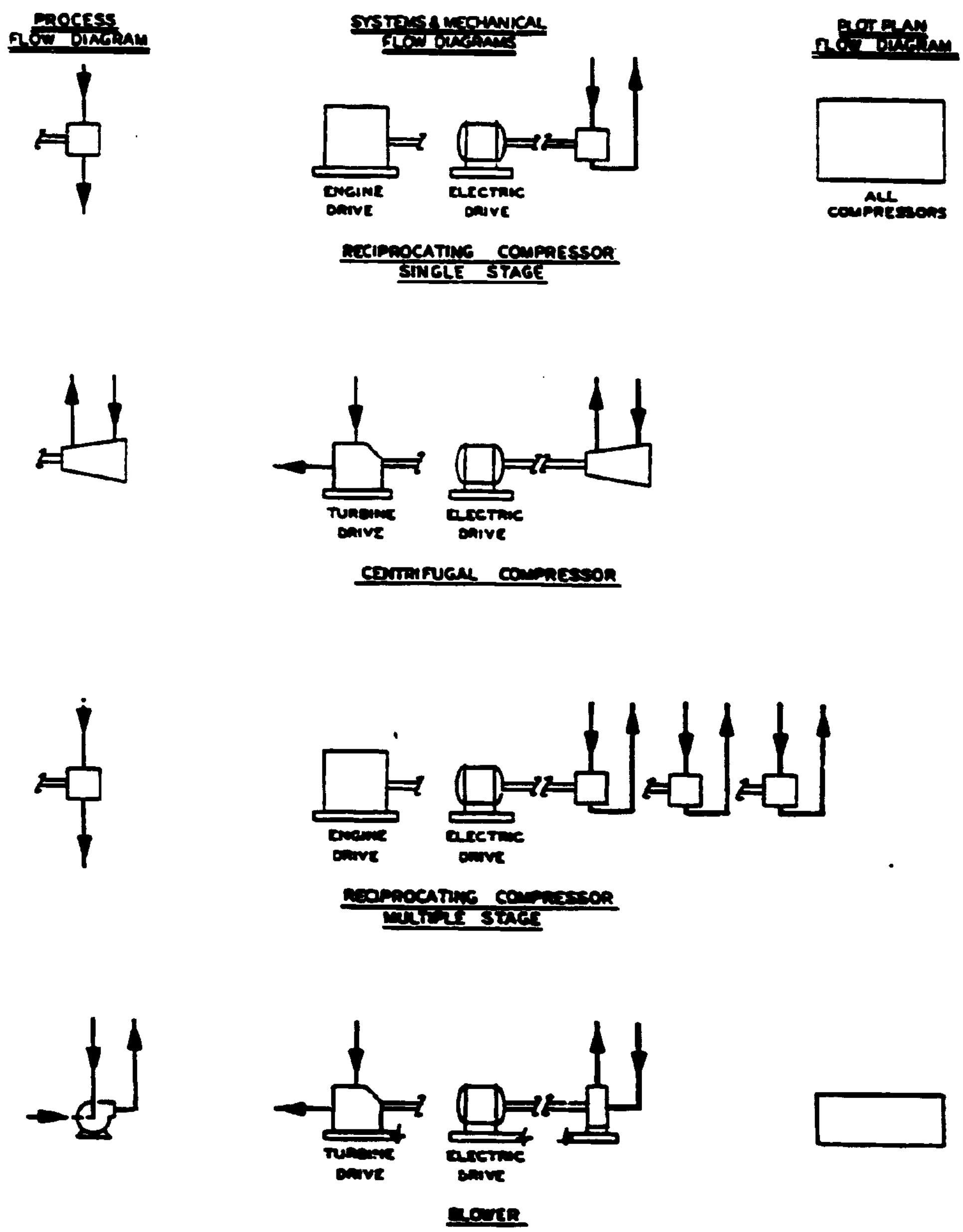




NOTE
SYMBOLS SHOWN ARE 1/2 ACTUAL SIZE SHOWN ON FLOW DIAGRAMS.

USE OR DISCLOSURE OF REPORT DATA IS SUBJECT TO THE RESTRICTION ON THE NOTICE PAGE AT THE FRONT OF THIS REPORT

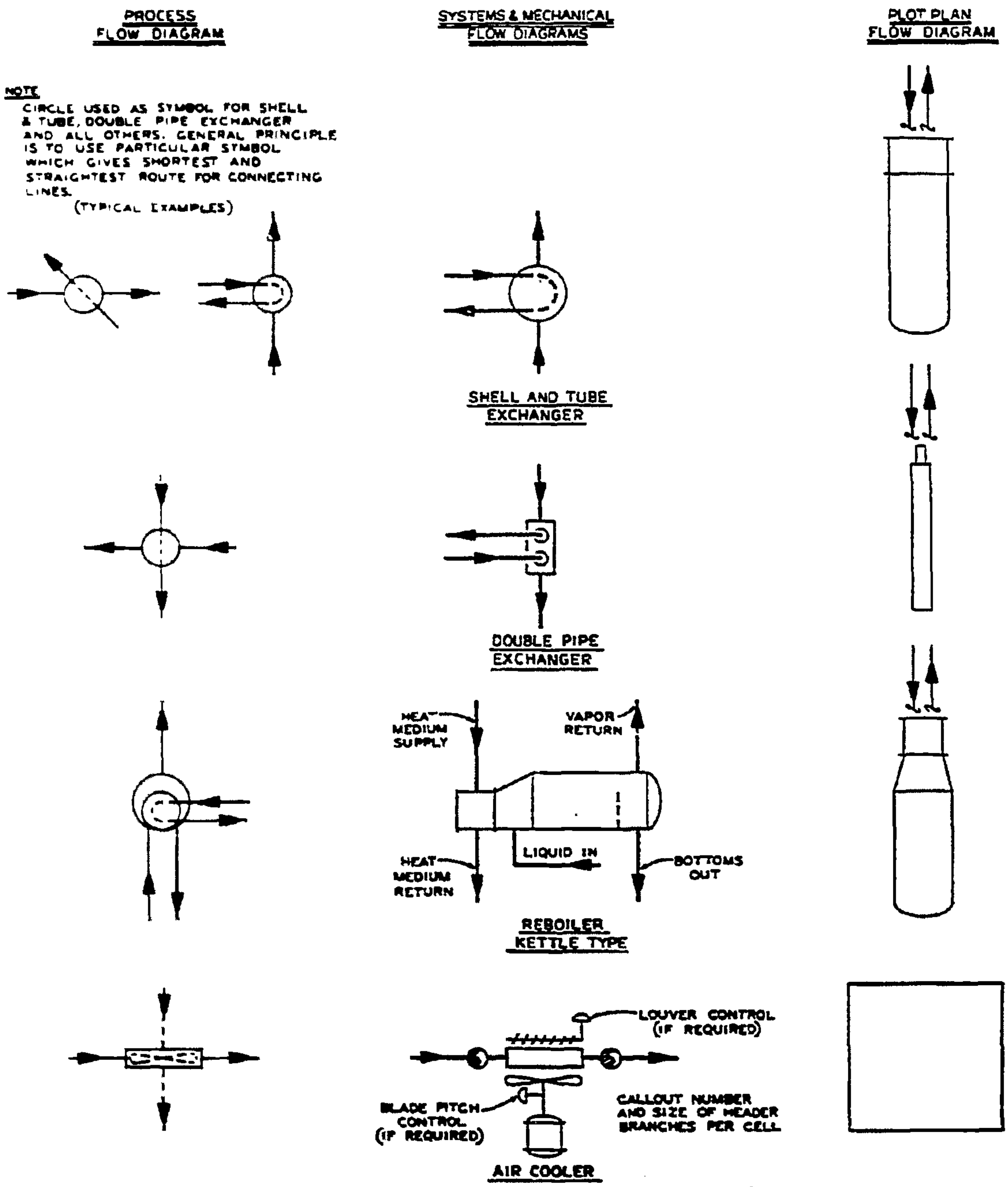
FLUOR ENGINEERING STANDARDS	FLOW DIAGRAM SYMBOLS COMPRESSORS AND BLOWERS	NUMBER ST-1-0011 PAGE DATE 7-77



NOTE

SYMBOLS SHOWN ARE 1/2 ACTUAL SIZE SHOWN ON FLOW DIAGRAMS.

FLUOR ENGINEERING STANDARDS	FLOW DIAGRAM SYMBOLS HEAT EXCHANGERS	NUMBER ST-1-0012 PAGE DATE 7-77



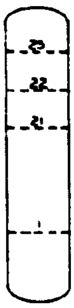
USE OR DISCLOSURE OF REPORT DATA IS SUBJECT TO THE RESTRICTION ON THE NOTICE PAGE AT THE FRONT OF THIS REPORT

FLUOR ENGINEERING STANDARDS	FLOW DIAGRAM SYMBOLS VESSELS AND FIRED HEATERS	NUMBER ST-1-0013 PAGE DATE 7-77

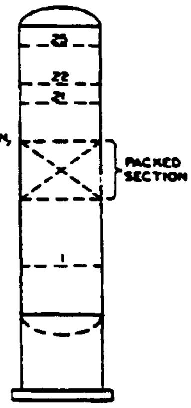
PROCESS FLOW DIAGRAM

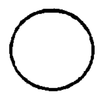
SYSTEMS & MECHANICAL FLOW DIAGRAMS

PLOT PLAN FLOW DIAGRAM

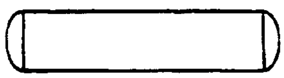


NOTE
1. TOP AND BOTTOM TRAYS AND ONLY THOSE NECESSARY TO LOCATE LINES, INSTRUMENTATION, SAMPLE CONNS. ETC. ARE SHOWN.
2. VESSELS ON EACH FLOW DIAGRAM ARE TO BE SHOWN IN APPROXIMATE RELATIVE SIZE TO EACH OTHER.

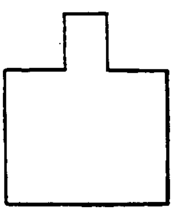


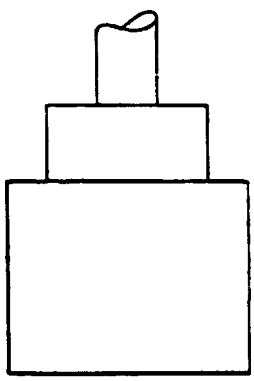


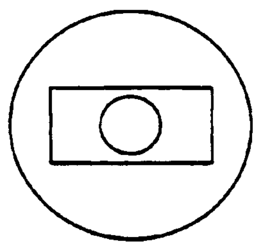
VERTICAL VESSELS



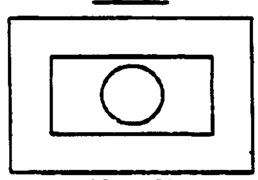
HORIZONTAL VESSELS







VERTICAL TYPE HEATER



BOX TYPE HEATER

FIRED HEATERS

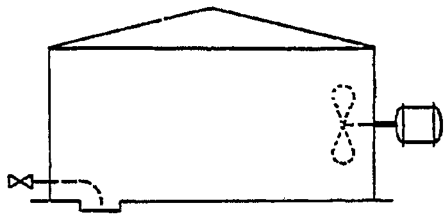
NOTE
HEATER SIZE IS AS REQUIRED TO SHOW CONFIGURATION, FIRING, NUMBER OF PASSES, STEAM GENERATION AND INSTRUMENTATION.

FLUOR ENGINEERING STANDARDS	FLOW DIAGRAM SYMBOLS TANKS & SPHERES	NUMBER ST-1-0014 PAGE DATE 7-77

PROCESS
FLOW DIAGRAM

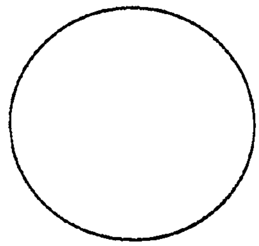
TANKS

SYSTEMS & MECHANICAL
FLOW DIAGRAMS

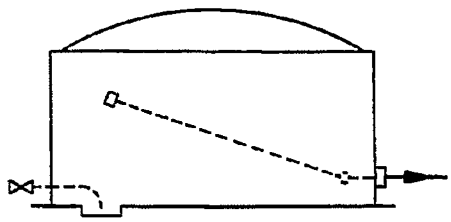


CONE ROOF
WITH AGITATOR
ELECTRIC DRIVE

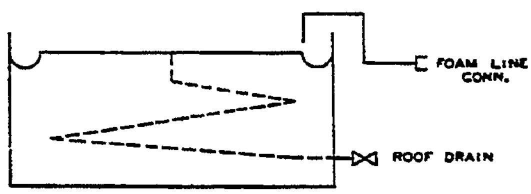
PLOT PLAN
FLOW DIAGRAM



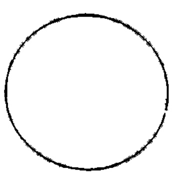
ALL
TANKS



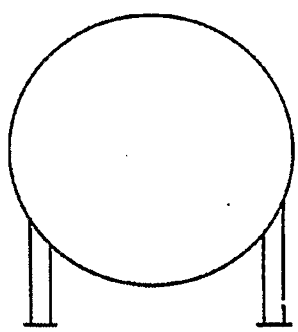
DOME ROOF
WITH SWING PIPE
FLOAT TYPE



FLOATING ROOF

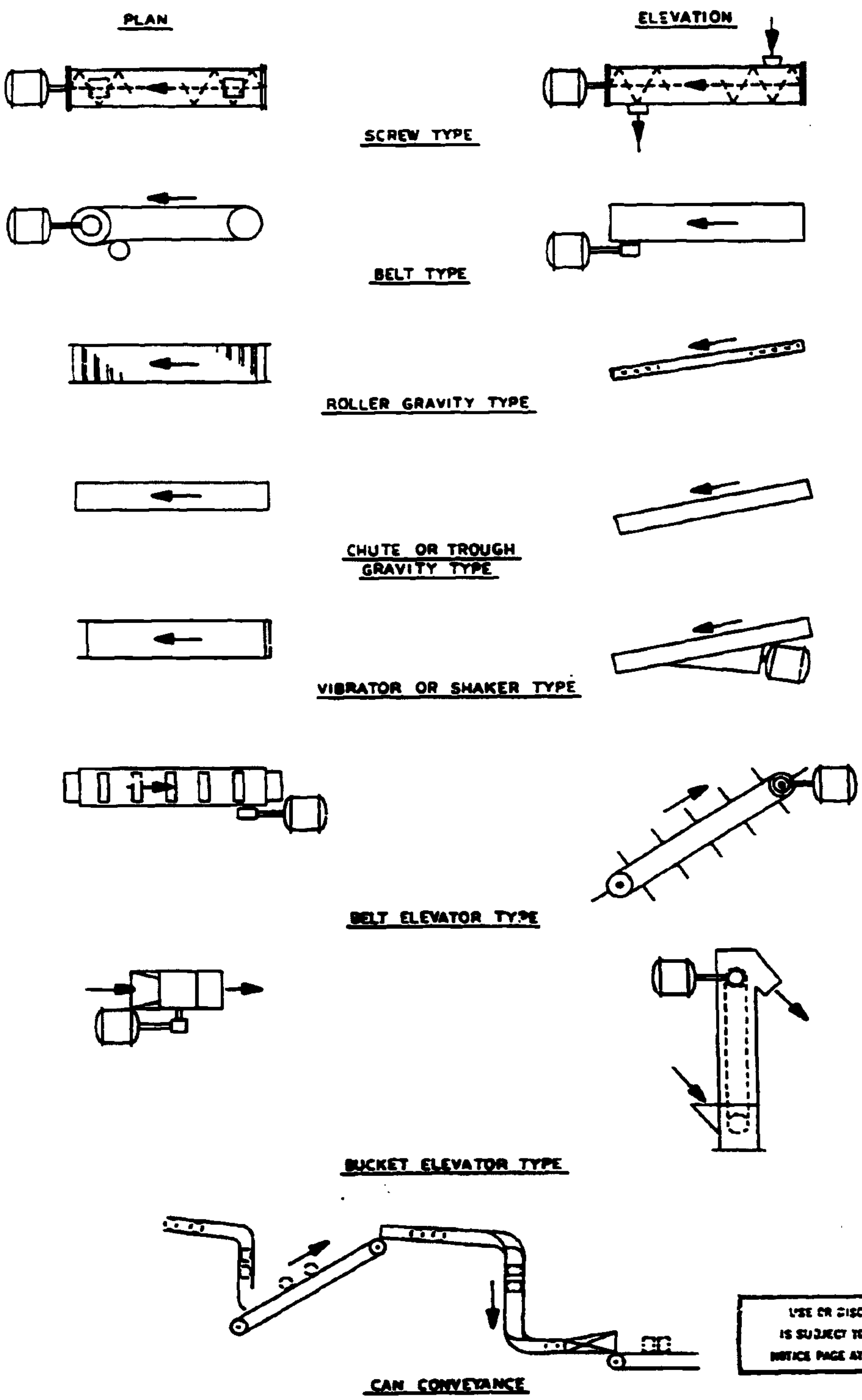


SPHERES



SPHERE

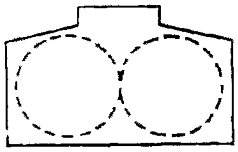
NOTE
ALL TANKS AND SPHERES ON EACH FLOW DIAGRAM ARE TO BE SHOWN IN APPROXIMATE RELATIVE SIZE TO EACH OTHER.



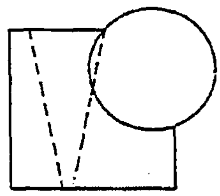
PLAN
ELEVATION
SCREW TYPE
BELT TYPE
ROLLER GRAVITY TYPE
CHUTE OR TROUGH GRAVITY TYPE
VIBRATOR OR SHAKER TYPE
BELT ELEVATOR TYPE
BUCKET ELEVATOR TYPE
CAN CONVEYANCE

FLUOR ENGINEERING STANDARDS	FLOW DIAGRAM SYMBOLS CRUSHERS AND SCREENS	NUMBER ST-1-0021 PAGE DATE 7-77

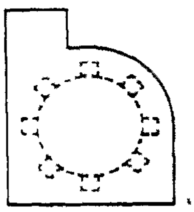
CRUSHERS



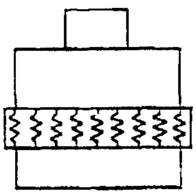
ROLL CRUSHER



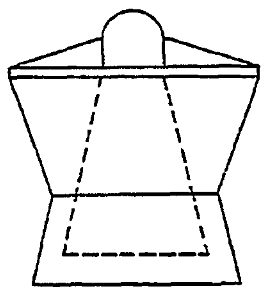
JAW CRUSHER



HAMMERMILL CRUSHER

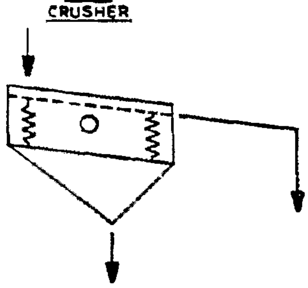


CONE CRUSHER

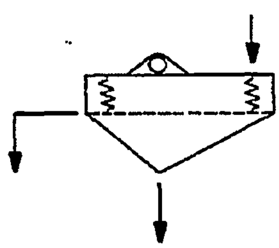


GYRATORY CRUSHER

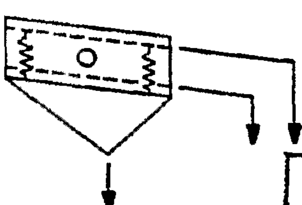
SCREENS



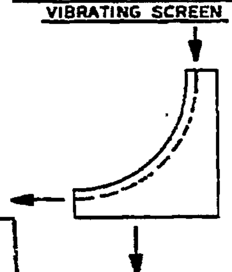
INCLINED SINGLE DECK VIBRATING SCREEN



HORIZONTAL SINGLE DECK VIBRATING SCREEN

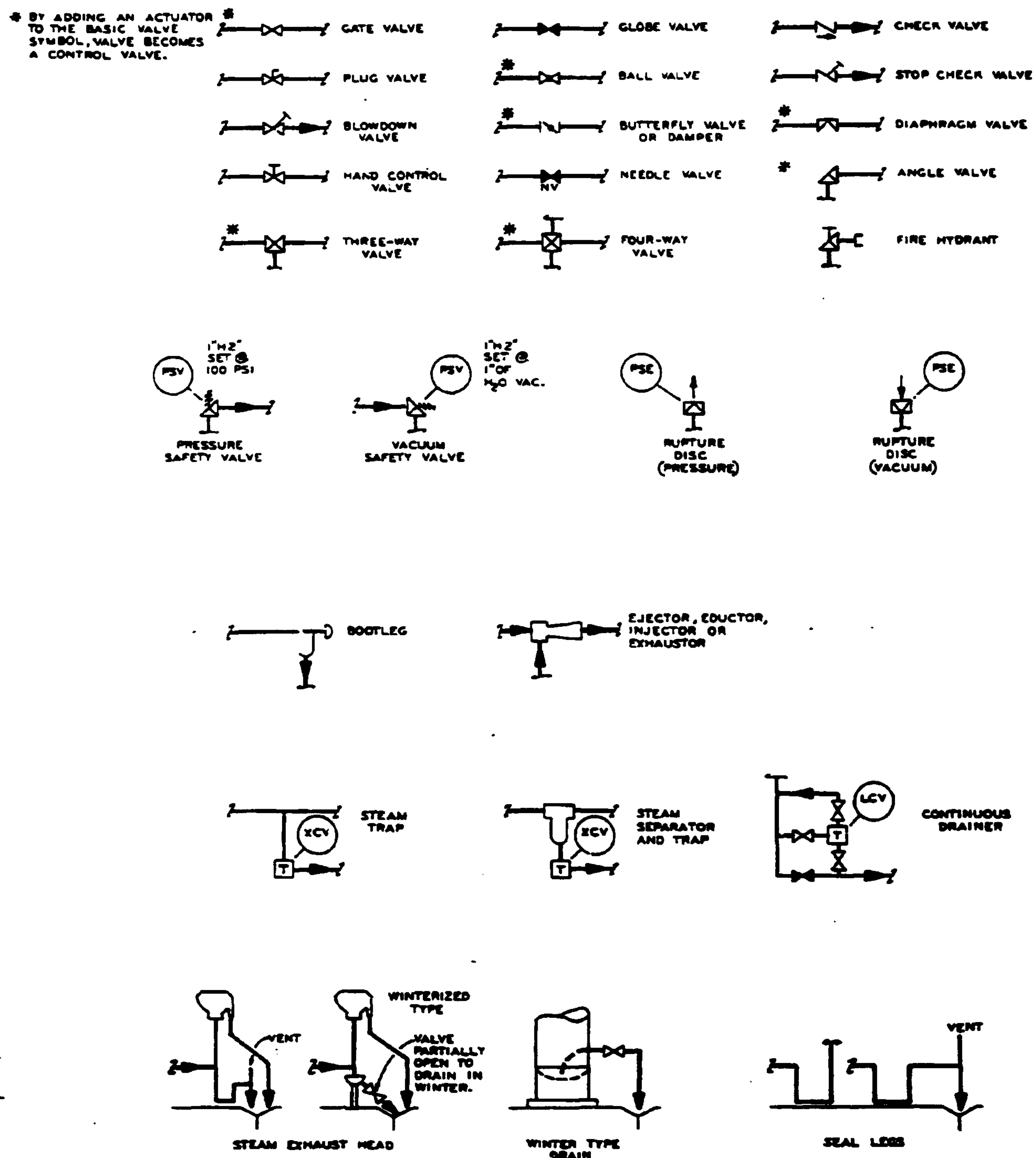


INCLINED DOUBLE DECK VIBRATING SCREEN



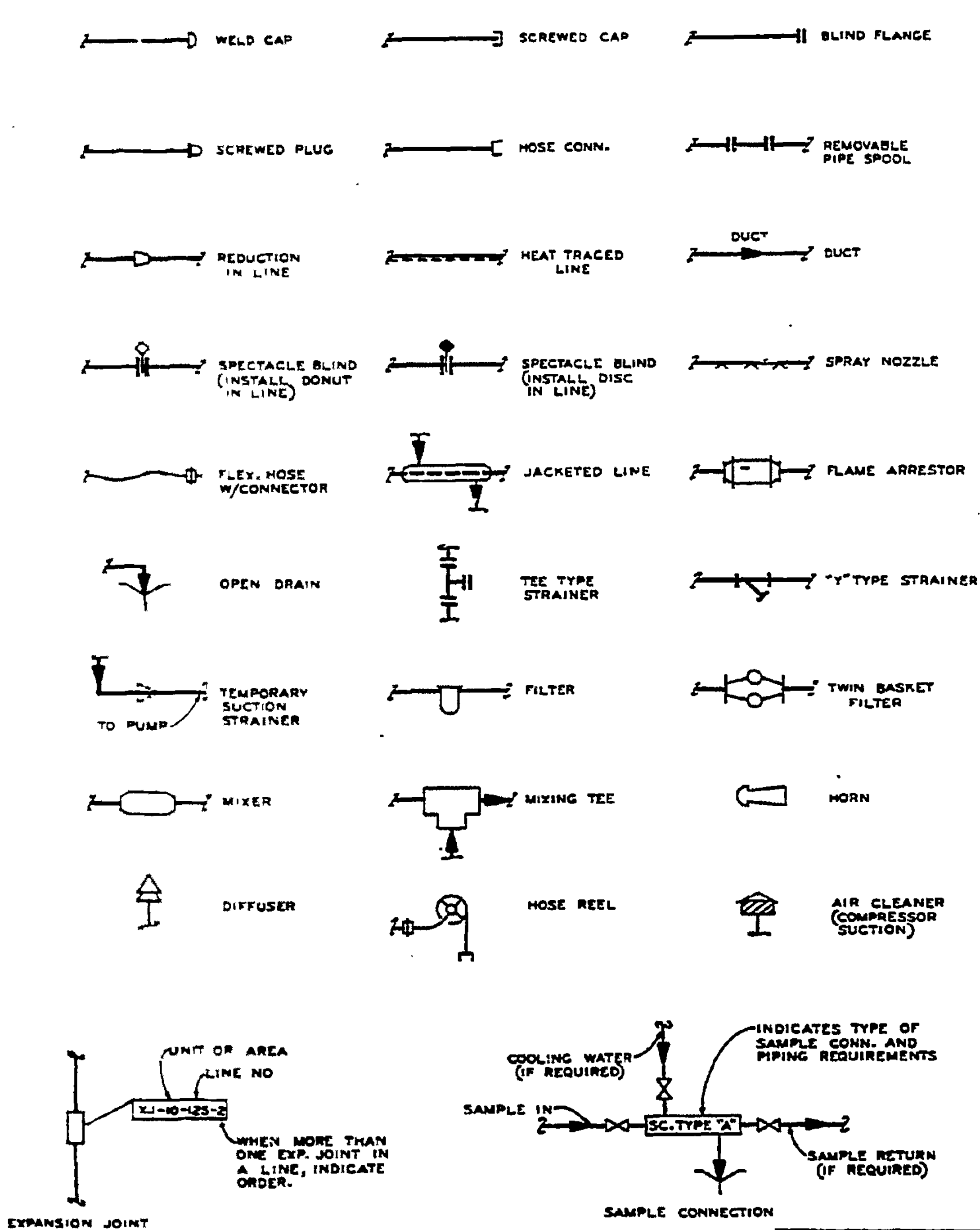
SIEVE BEND

FLUOR ENGINEERING STANDARDS	FLOW DIAGRAM SYMBOLS VALVES, FITTINGS AND MISCELLANEOUS PIPING	NUMBER ST-1-0030 PAGE 1 of 2 DATE 7-77



NOTE
SYMBOLS SHOWN ARE 1/2 ACTUAL SIZE SHOWN ON FLOW DIAGRAMS.

FLUOR ENGINEERING STANDARDS	FLOW DIAGRAM SYMBOLS VALVES, FITTINGS AND MISCELLANEOUS PIPING	NUMBER ST-1-0030 PAGE 2 DATE 7-77



NOTE:
SYMBOLS SHOWN ARE 1/2 ACTUAL SIZE SHOWN ON FLOW DIAGRAMS.

Revision 01

PROCESS CRITERIA

4.0 UTILITIES

The purpose of the following information is to provide design criteria for utilities within process units. The intent is to arrive at uniform systems that can be integrated into an overall plant design.

A writeup defining the cooling media (air or water) will be included in this section at a later date.

4.1 Steam, Condensate and Boiler Feedwater

4.1.1 Steam

a. Steam will be made available at the pressure levels shown in Table 4.2 (in Appendix located at the end of this section) at plot limits. All efforts should be made to produce steam from waste heat at levels consistent with the values shown. Any deviations should be brought to Fluor's attention.

b. All process units shall be designed to minimize the net export of low pressure steam during normal operations.

c. Waste heat steam generators shall be designed to remain in continuous operation for a minimum of two (2) years.

d. Construction of waste heat steam generators and related piping shall be to ASME Boiler Code.

e. When forced circulation boilers are provided, the water circulation/steam generation ratio shall be not less than 5:1.

f. The control, monitoring and warning instruments for waste heat steam generating systems shall be located in the respective process control rooms. These controls shall include those for the steam pressure, steam superheat temperature, where applicable, high/low water levels, and steam flow rate.

   The system shall be designed for local indication and control as well as control from the respective process control room.

   As a minimum, the following variables shall be permanently recorded:

   1) Steam flow from each generator.

2) Steam temperature at exit of superheaters.

3) Water level in steam drum, and kettle-type generators.

4) Steam drum pressure.

4.1.2 Blowdowns

a. All steam generators and steam drums will be blown down as necessary to maintain the allowable solids in the drum consistently below the limit imposed by the American Boiler Manufacturer's Association (Table 4.3).

b. Blowdown piping will be Sch. 160 with no pockets, using swept tees and long radius bends when changing direction of flow. Effluent from the blowdown drums, after cooling, will be collected for further treatment.

4.1.3 Condensates

a. Steam condensate from low pressure and medium pressure steam users shall be collected in the "L.P. Condensate Collection" header.

b. Steam condensate from high pressure steam users shall be collected in the "H.P. Condensate Collection" header where available.

c. Maximum steam condensate conservation shall be practiced.

d. Excess steam condensate which is collected within an operating unit shall be returned to the Steam Generation Plant via the "Pumped Condensate Return" header.

e. All condensate streams which can be potentially contaminated shall be provided with appropriate analyzers and alarms. A contaminated condensate stream shall be diverted from the condensate collection system. Disposition of the potentially contaminated condensate will be determined by the water management group at Fluor.

4.1.4 Boiler Feedwater

a. Returned condensate plus demineralized water will be deaerated and treated in the Steam Plant and distributed factory-wide as "LP Deaerated Condensate".

b. "LP Deaerated Condensate" shall be boosted onsite to meet high pressure waste heat boiler feedwater requirements.

c. Non-deaerated steam condensate shall be distributed as "HP Condensate Supply" or "LP Condensate Supply" to meet certain process water requirements.

d. "Polished water" shall be distributed to onsite deaerators where ultra-purity boiler feedwater is specified for process reasons.

4.2 Water Systems

4.2.1 Cooling Water

a. Central cooling water systems will supply all required cooling water to process units. Water will be available (at plot limits) at the conditions detailed in Table 4.2.

b. Use of cooling water from this system shall be kept to an economic limit, with maximum use of air cooled heat exchangers. The break point for air versus water cooling in individual services shall be determined by an economic evaluation. As a general rule, for product stream, air cool above 130°F and water cool below 130°F.

c. Fouling factors on the cooling water side of heat exchangers shall be as shown on Table 8.1 located in the section titled Heat Exchangers.

4.2.2 Potable Water

Potable water will be supplied to all process units, at the conditions (at plot limits) specified in Table 4.2.

4.2.3 Utility Water

Utility water will be supplied to all process units, at the conditions (at plot limits) specified in Table 4.2.

4.2.4 Firewater

Firewater will be supplied to all process units, at the conditions specified in Table 4.2.

4.3 Fuels

4.3.1 Fuel Gas

a. All process heaters except the utility boilers and sulfur off-gas incinerator will be designed for fuel gas firing only.

b. Fuel gas will be supplied as required at all process plot limits at the conditions shown in Table 4.2. Heating value will range from 330 to 450 BTU/SCF (LHV). Molecular weight will range from 12 - 17.

c. Fuel gas will be "wet". Knockout drums are required at minimum safe distance from each fired heater or group of heaters. Condensate collected in the knockout drums will be routed to the flare header.

4.3.2 Fuel Oil

a. Low grade by-products can be considered for use as fuel.

b. For design purposes fuel oil will have the properties listed in Table 4.1. By-product streams used as fuel oil have their own unique properties. These properties must be given to Tri-States by the process licensor producing the fuel oil.

TABLE 4.1

FUEL OIL SPEC

Viscosity	Centistokes @ 120°F.
Density	lb/ft^3 max.
Sulfur	% max.
Heating Value	BTU/lb.
Flash Point	°F min.

Pour Point	°F max.
Water	wt % max.
Ash	wt % max.
Sediment by extraction	wt % max.

4.3.3 Coal fines will be used to fire the utility boilers except for start-up.

4.4 Air and Nitrogen Systems

4.4.1 Instrument Air

a. Instrument air will be available at plot limit of each process unit at the conditions shown in Table 4.2.

b. Instrument air will be dried to -40°F dew point at the supply pressure.

4.4.2 Plant Air

a. Plant air will be available at plot limit of each process unit at the conditions shown in Table 4.2.

b. Plant Air shall serve as a "Backup" source of Instrument Air; for automatic use in the event of an outage of the latter. In such eventualities, the Instrument Air shall have first call on the Plant Air production with regard to other users. The flow to other consumers will be automatically curtailed; to the extent required to satisfy the Instrument demand.

c. The normal supply of Plant Air shall be saturated with water vapor.

An exception would be the flow diverted to the Instrument Air System under unusual conditions. This air would pass through Driers to reduce the effluent Dew Point to - 40 °F or lower.

4.4.3 Nitrogen

a. Nitrogen (99.9 volume %) purity will be available at plot limit of each process unit at the conditions shown in Table 4.2.

b. Nitrogen pressure shall be boosted as required within the various process units to meet their requirements.

4.5 Drivers

4.5.1 General

In general, all large drivers will be steam turbines using high pressure superheated steam (temperature and pressure to be given later) and designed for condensing at 4 inches of mercury absolute.

4.5.2 Electric Motors

a. Electric motors shall have horsepower ratings at least equal to 110% of the design horsepower except that electric motors for centrifugal pumps should have horsepower ratings as follows:

Motor Rating - HP	% of Pump - HP
Up to 25	125
30 to 75	115
100 and over	110

b. Electricity will be available as follows:

Main distribution voltage:	13.8kV at 60Hz.
Motors 1/2 HP through 200 HP:	0.48kV, 3ph, 60Hz.
Motors 250 HP through 3000 HP:	4.16kV, 3ph, 60Hz.
Motors over 3000 HP:	Special Consideration.
Lighting:	120V, 1ph, 60Hz.
Instruments:	120V, 1ph, 60Hz.

4.5.3 Steam Turbines

a. Unless otherwise stated, all steam turbines should comply with the requirements of API Standard 611 as applicable.

b. Steam turbines in sizes above approximately 450 kW are to be considered "Special Purpose" API 612 type and should be of the multivalve type having all valves under governor control.

c. "Special Purpose" steam turbines should be fitted with a variable speed governor (Woodward or equal). The governor shall be readily accessible and operable.

d. All turbines shall be equipped with an overspeed safety trip mechanism mounted directly on the turbine shaft.

e. Where turbine casings are not designed to withstand the design pressure of the steam main, they should be protected by relief valves capable of passing the full rated flow of steam.

4.6 Site Conditions

Table 4.4 summarizes the site conditions given in various sections in this manual.

APPENDIX

Revision 01

PROCESS CRITERIA

UTILITY DESIGN INFORMATION

TABLE 4.2

	Operating Conditions At Producer Battery Limits (PSIG)	(°F)	Minimum Operating Conditions At User Battery Limits (PSIG)	(°F)	Piping Design Conditions (PSIG)	(°F)
Power Station Steam	1500	900				
H.P. Superheated Steam	600	750	537(1)	(1)	650	800
H.P. Saturated Steam	625(3)	492	610	490	725	550
Medium Pressure Steam	120	350	100	337	135	375
Low Pressure Steam	60	307	50	297	90	330
Utility Steam (8)	120	350	100	337	135	375
H.P. Condensate Return	120	350	---	---	145	480
L.P. Condensate Return	15(5)	245	---	---	145	390
Pumped Condensate Return	175	210	110	195	200	300
L.P. Deaerated Condensate (BFW)	175	230	145	220	220	275
H.P. Condensate Supply	600	230	580	220	750	300
L.P. Condensate Supply	275	230	(6)	220	350	300
Polished Water (Deaerator F.W.)	95	105	60	100	120	210
Utility Water (9)						
a. General Factory	100	80(2)	70	80	145	120
b. Stripped Gas Liquor	100	85	70	85	145	140
c. Clarified Ash Water	70	105	70	105	145	140
Firewater	200	80(2)	160	80	260	120
Potable Water	130	80(2)	80	80	145	120
Process C.T. Supply (10)	70	85	60	85	100	140
Process C.T. Return, Max.(10)	---	105	35	105	100	140
Utility Air	125	95	100	95	145	140
Instrument Air	125	95	90	95	145	140
Nitrogen, L.P.	50	95	35(7)	95	145	140
Nitrogen, H.P.	510	95	495	95	550	140
Fuel Gas	60(4)	105	40	100	145	160

PROCESS CRITERIA

UTILITY DESIGN INFORMATION

TABLE 4.2
(Continued)

NOTES:

(1) At Unit 10, _____ at _____. At Unit 20, _____. At all other unit battery limits, minimum _____, expected _____.

(2) Summer condition, lowest expected winter conditions is _____.

(3) Normal, _____; maximum, _____.

(4) At Unit 12, _____.

(5) At Unit 21, _____.

(6) At Unit 29, _____. At Unit 15, _____.

(7) At Unit 20, _____.

(8) In units where low pressure steam is required for process use and medium pressure steam is not required, use low pressure steam for utility steam.

(9) Stripped gas liquor is utility water for Units 11, 12, 13, 16, and 17. Clarifed ash water is utility water for Unit 10.

(10) For all units except Oxygen and Steam Plants. Responsible contractors for these plants will be notified re cooling water supply and return conditions.

General Note:

Fluor is integrating the design of the waste heat boiler feedwater and condensate supply and return systems. The use of these systems must be confirmed with Fluor.

PROCESS DESIGN CRITERIA

TABLE 4.2
(Continued)

I. STEAM SYSTEMS

H. P. Superheated Steam

H. P. Superheated Steam from the Boiler Plant and from other Process sources which export this commodity will be made so that conditions will be 600 psig and 750°F (minimum) at the producer's Battery Limits.

It should be recognized in a complex covering the area envisaged for Tri-States, that minimum operating conditions at user Battery Limits will vary throughout the complex.

Temperatures up to 806°F are possible in startup and normal operation.

At Unit 20 (Fischer-Tropsch Synthesis), a station will be provided to mix the H. P. Superheated steam with any excess H. P. Saturated steam produced in Unit 20 for use as turbine steam in Unit 20 only. The minimum allowable temperature to the turbines shall be determined by consultation among the turbine vendor and Fluor.

Low Pressure Steam

The Piping Design temperature has been set to reflect the production of this steam from process heat recovery generators (at saturated conditions) and a small quantity let-down from Medium Pressure Steam.

II. CONDENSATE SUPPLY AND RETURN, AND FEEDWATER SYSTEMS

H. P. Condensate Return

Condensates produced from H. P. Steam will be gathered in a header system within Process Units and delivered to their Battery Limits at a minimum of 120 psig, unless a suitable destination exists within Battery Limits.

PROCESS CRITERIA

L. P. Condensate Return

Condensate produced from either M. P. or L. P. Steam will be gathered in a header system within Process Units. If a collection drum is not provided inside producer battery limits, this stream should be brought to Battery Limits at a minimum of 15 psig.

Pumped Condensate Return

Whenever a drum exists within a Process Unit for collecting L. P. Condensates, a pump will be provided to convey this stream to Battery Limits at a minimum of 175 psig. If a process unit has a small quantity of H. P. Condensate return, it may be combined into the L. P. Condensate Drum Feeds after obtaining approval by Fluor.

Surface Condenser Condensate

Battery Limit conditions for export would be the same as pumped condensate return.

L. P. Deareated Condensate (BFW)

This is the stream designated for Waste Heat Boilers.

H. P. and L. P. Condensate Supply

This stream will be made available to users needing high quality process water but which can tolerate some hydrocarbon contamination. The condensate supply systems will be monitored and any hydrocarbon contaminated condensate will be diverted and replaced by condensate quality make-up.

Polished Water

High quality Polished demineralized water will be provided to Unit 24 (Ethylene Plant), at the conditions shown.

PROCESS CRITERIA

III. OTHER SYSTEMS

Raw Water and Flocculated "BFW" Make-Up

No factory-wide distribution will be made of these streams.

Utility Water

a. General Factory use, except as noted in (b) and (c) below. Treated effluent water from biotreating maturation pond; subsequently cold lime softened and filtered before pumping into general Factory utility water distribution system.

b. Units 11 (Gas Cooling), 12 (Rectisol), 13 (Gas Liquor Separation), 16 (Phenosolvan), and 17 (Ammonia Recovery) use stripped gas liquor because associated conservation sewers cannot tolerate contamination by general Factory utility water.

c. Unit 10 (Gasification) uses clarified ash water from Unit 03 in utility water services.

Note: Maturation pond water is Factory effluent water which has been pretreated for reduction of fluoride content, biotreated, and then stored in the maturation pond for further reduction of any remaining biodegradable materials.

Firewater

Firewater reserve storage is maintained full from raw water supply to Factory. As backup, can be filled from flocculated raw water makeup. Firewater producer and user battery limit operating conditions were changed to provide pressure required to operate foam generators and fight structure fires.

Potable Water

Supplied from outside of Factory.

PROCESS CRITERIA

TABLE 4.3

Pressure at Outlet of Steam Generator psig	Maximum Concentration Permissible In Upper Drums,* ppm			
	Silica	Total Alkalinity	Suspended Solids	Total Solids
0-300	125	700	300	3500
301-450	90	600	250	3000
451-600	50	500	150	2500
601-750	35	400	100	2000
751-900	20	300	60	1500
901-1000	8	250	40	1250
1001-1500	2.5	200	20	1000
1501-2000	1.0	150	10	750
Over 2000	0.5	100	5	500

*From American Boilers Manufacturer's Association

PROCESS CRITERIA

TABLE 4.4

SITE CONDITIONS

The conditions below are for the site:

Temperature, °F	
Summer Dry Bulb (Design)	96
Summer Wet Bulb (Design)	79
Winter Dry Bulb (Design)	6
Design for Freeze Protection °F With 30 mph Wind	-5
Design Frost Line, Feet Below Surface	4
Wind Speed, Miles per Hour	
Average	8.3
Peak Gust	113
Plant Elevation, Feet Above Sea Level	381
Normal Atmospheric Pressure, psia	14.5
Annual Precipitation, Inches	41.45
Annual Evaporation, Inches	30

PROCESS CRITERIA

5.0 ECONOMICS

5.1 Introduction

Design work must be based on the procedures and specifications set forth for the Tri-State Synfuels Project. However, it is encouraged that flow arrangements and equipment arrangements be critically reviewed so all alternatives that will make the project more economical will be evaluated. Incremental investments should be evaluated using an annualized cost basis assuming a 25 year plant life and a cost of capital of 17 percent.

5.2 Economic Evaluations

5.2.1 The economic formula defined in the following paragraphs applies only to comparative studies and to incremental (marginal) capital.

5.2.2 Formula

Evaluations should be done using an annualized cost approach. The alternative with lowest total annualized cost will be the most favorable. Total annualized cost should be calculated for each alternative as follows:

$$TAC = C + R + (YCF)(ACF)$$

where

TAC = Total Annualized Cost
C = Total Capital Cost
YCF = Yearly Cash Flow from operations equal to product value less the cost of raw materials less the cost of operation and maintenance less overhead costs.
ACF = Annual Cost Factor

$$= \frac{(1+i)^n - 1}{i(1+i)^n} = 5.77 \text{ for}$$

n = Plant Life = 25 years,
i = Cost of Capital = 17%.
R = Royalties (Assuming lump sum royalty payment. For running royalty this must be annualized)

Note: Cash Flow excludes depreciation and taxes.

PROCESS CRITERIA

5.2.3 Operating Costs

Utilities

To be determined from Table 5-1.

Labor

$ * yearly per operator and 4.8 operators required for each position.

Maintenance

Use 2 to 5% of capital, 60% labor, 40% materials.

Catalyst and Chemicals

Use Table 5-2 or obtain cost estimates from suppliers.

Overhead

Use 33% of all labor for supervision and 2.5% of capital for general overhead.

Royalties

To be supplied by the licensor for running royalties.

5.2.4 Product Values

See Table 5-3.

5.2.5 Feed Values

Feed	Costs
Coal	$ * per Ton

5.2.6 Capital Investment

This is the total capital cost including direct field costs plus home office and field indirect costs also contractor fees but excluding any contingency allowances. Lump sum royalties are also included.

* Note: To be supplied by Tri-State.

PROCESS CRITERIA

TABLE 5-1

UTILITY COSTS

Electric Power	\$0.055 /KWH
Cooling Water (Circulated)	\$0.053 /Mgal
Boiler Feedwater Makeup	\$0.98 /Mgal
Raw Water	\$0.50 /Mgal
HP Steam (600 psig-750°F)	\$3.25 /Mlb
LP Steam (120 psig sat'd)	\$2.45 /Mlb
Fuel Gas (LHV)	\$5.00 /MMBTU

(Utility cost calculations should show sensitivity to cost increases of 100 percent and 200 percent.)

Copies of all economic studies are to be given to Tri-State Synfuels/Fluor for their review and comment.

PROCESS CRITERIA

TABLE 5-2

CATALYST AND CHEMICAL COSTS

Material	Cost
Catalysts	*
Chlorine	$145.00/ton
Sodium Hydroxide	0.75/lb
Methanol	0.80/lb
Sodium Carbonate	60.00/ton
Citric Acid, Anhy.	0.75/lb
Propylene	0.20/lb
Potassium Carbonate	0.25/lb
Magnesium Oxide	1.08/lb
Hydrated Lime	0.35/lb
Hydrazine	2.50/lb
Dimethyl Sulfide	0.37/lb
Phosphoric Acid	0.25/lb
Activated Carbon	*
Zeolite	*
Ethylene Dichloride	0.15/lb
Molecular Sieves (Type 4A)	*
Hydrofluoric Acid	0.56/lb
Potassium Hydroxide	0.95/lb
Calcium Chloride	110.00/ton
Polyflo Antifoulant P-140	*

* Obtain costs from vendors.

Note: Prices for chemicals not given in this table should be obtained from appropriate vendors.

(Catalyst and Chemical Cost Calculations should show sensivity to cost increases of 100% and 200%).

TABLE 5-3

PRODUCT VALUES

Chemical	$/lb
Anhydrous Ammonia	*
Sulphur	*
Unleaded Gasoline	*
Methanol-Fuel Grade	*
Methanol-Chemical Grade C	*
Isobutane	*
Mixed Butanes	*
Aromatic Naphtha	*
**Phenols	*
SNG	*
LPG	*

**depitched

* Note: To be supplied by Tri-State.

PROCESS CRITERIA

6.0 MATERIALS OF CONSTRUCTION

6.1 Sources of Information

The following sources shall be used in the selection of materials of construction and corrosion rates:

6.1.1 Selection of steels exposed to hydrogen service is based on API-941, 1977 Second Edition.

6.1.2 Corrosion rates for steels subject to a hydrogen sulfide environment shall be in accordance with "Computer Correlations to Estimate Corrosion of Steels by Refinery Streams Containing Hydrogen Sulfide," by Couper and Gorman; NACE Paper No. 67. Add 50% to corrosion rate determined from these curves.

6.1.3 Corrosion rates for steel subject to sulfur bearing hydrocarbons shall be in accordance with "High-Temperature Sulfidic Corrosion in Hydrogen-Free Environment," by Henry F. McConomy.

6.1.4 Equipment in sour water or wet sulfide service may require special consideration. Killed carbon steel shall be used for equipment if carbon steel is the material of construction. Refer to SP-1001-50-3, "Piping Materials", for piping materials. Carbon steel welds shall have a maximum Brinell hardness of 200 when subject to sour water service. If CN^- or other poisoners are present, carbon steel welds shall have a maximum Brinell hardness of 185.

6.1.5 Equipment in pressurized wet CO_2 service may use carbon steel where ammonia-rich oil-gas liquor is available to coat the steel. Stainless steel 304L should be used where appreciable concentrations of CO_2 in water exist at higher temperatures without gas-liquor present.

6.1.6 For caustic service, the caustic service chart in the Corrosion Data Survey, 5th Edition, published by the National Association of Corrosion Engineers. Materials in hot carbonate and amine treating service shall also use the aforementioned reference.

6.1.7 Anhydrous ammonia vessels and highly stressed piping in anhydrous ammonia service shall be stress relieved.

PROCESS CRITERIA

6.2 Metallurgical Drawing

Metallurgical drawings covering pressure-temperature profile and materials of construction of the various items shall be prepared for each individual unit. A reproducible copy of the Process Flow Diagram will be used to construct these drawings.

6.3 Equipment Life

Corrosion allowances shall be based on equipment life in accordance with the following table:

Equipment	Life
Columns, Drums and Reactors	20 years
Heat Exchanger Shell	20 years
Heat Exchanger Tubes	5 years
Pumps	20 years
Compressors	10 years
Heater Tubes	100,000 hours
Atmospheric Tankage	20 years
Piping Materials	10 years

6.4 Minimum Corrosion Allowance

Where sufficent data is not available to calculate corrosion rates, the following criteria shall be applied (except for overriding process conditions).

Equipment and Service	Minimum Corrosion Allowance
a. Columns, Drums, Reactors, Tanks and Heat Exchangers (except tubes)	
Noncorrosive, Carbon Steel and Low Alloy	1/8" Shell & Heads
Corrosive, Carbon Steel	1/4" Shell & Heads
Low Alloy	1/8" Shell & Heads
Corrosive, High Alloy	1/16" Shell & Heads and removable internals
b. Pumps and Compressor Casings	1/8" Shell & Heads
c. Heater Tubes	
Carbon Steel and Low Alloy	1/16" Shell & Heads
High Alloy	1/16" Shell & Heads

d. Piping

Noncorrosive, Carbon Steel and Low Alloy	1/16" Shell & Heads
Corrosive, Carbon Steel and Low Alloy	1/8" Shell & Heads
Corrosive, High Alloy	1/16" Shell & Heads

6.5 Lethal, Caustic, and Sour Water Service

6.5.1 Equipment in lethal, caustic or sour water service shall be specifically identified.

6.5.2 Lethal service includes gases or liquids of such nature that a very small amount of the gas or of the vapor from a liquid mixed or unmixed with air is dangerous to life when inhaled (such as Hydrocyanic Acid, Carbonyl Chloride, and Cyanogen). Not included are Natural Gas, SNG, LPG and other petroleum products or streams containing H_2S, Chlorine, and Ammonia in trace quantities.

PROCESS CRITERIA

7.0 VESSELS AND COLUMNS

All vessels and columns shall be designed, fabricated and inspected in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, Pressure Vessels or Division 2, Alternative Rules and Specification SP-1001-42-1. The following criteria governs the general requirements for the process design of pressure and vacuum vessels and columns. A process design data sheet shall be prepared for each vessel, column or reactor.

7.1 Column Sizing

7.1.1 Preliminary rating of columns shall be conducted by the process engineer. Except for specific applications, valve trays shall be specified for columns. Column sizing shall be made on the basis of 80% (maximum) flooded capacity. Fluor will check data on Vendor's proposals to determine adequacy of sizing.

7.1.2 Allowance shall be made for system factors to compensate actual vapor and liquid loads for deviation from the basic light hydrocarbon systems. The system factor shall be specified by the process designer.

7.1.3 Minimum trayed column size to be 36" inside diameter.

7.2 Design Pressure

Design pressure of vessels and columns shall be set in accordance with Table 7.2.

TABLE 7.2

DESIGN PRESSURE CRITERIA

Operating Pressure(1), psig	Design Pressure, psig(2)(3)(4)
0 to 5	Operating +1.5(5)
5 to 150	Operating +15
150 to 500	Operating +10%
500 to 1000	Operating +50
1000+	Operating +5%
Vacuum (full)	14.5 Psia external or zero psia
Vacuum (partial)	External design pressure = max. operating external pressure + 1.5psi(6)

PROCESS CRITERIA

Notes:

(1) Operating pressure is defined as maximum operating pressure at top of vessel.

(2) Allowances for pressure drop across internals, hydrostatic head and weight of catalyst or packing must be added to the operating pressure to arrive at the design pressure for the lower section of the vessel.

(3) Where there is a possibility that vacuum conditions might be experienced during operations, vessels should be designed accordingly. If steamout is of frequent occurrence or is part of the process cycle, external design pressure shall be 7.5 psig. Closed vent during steamout for shutdown or hydrostatic test shall not be considered reasons for designing vessels for vacuum.

(4) The most severe coincident conditions of temperature and pressure should also be specified and considered in the design.

(5) Allows for exclusion of storage tanks and low pressure vessels from code requirements.

(6) Minimum external design pressure 3 psi.

(7) Vessels subject to pressurization and depressurization during the operating life of the unit shall have the frequencies noted on the process data sheet.

7.3 Design Temperature

The following guidelines shall be used in determining design temperature when operating temperature exceeds 60°F.

7.3.1 For operating temperatures of 600°F or less, the design temperature is the operating temperature plus 50°F.

7.3.2 For operating temperatures between 600°F and 625°F, use 650°F design temperature.

7.3.3 For operating temperatures of 625°F or more, the design temperature is the operating temperature plus 25°F.

7.3.4 The operating temperature is defined as the maximum temperature encountered during normal operation, start-up or shutdown. An alternate operating temperature and pressure should be specified for situations such as catalyst regeneration.

7.3.5 Both top and bottom operating temperatures should be specified for columns. Normally, design temperature shall be based on bottoms temperature. However, two or more design temperature zones should be specified if economic considerations dictate (i.e. alloy material, stress values).

7.3.6 Low temperature operating conditions should be taken into consideration for the design. For operating temperatures of 60°F or lower, the design temperature should be 10°F below the operating temperature. Operating temperature for low temperature service should be taken as the minimum temperature encountered during normal operation, start-up, or shutdown.

7.3.7 The most severe conditions of temperature and pressure shall be specified and considered in the design.

7.3.8 Vessels subject to changes in operating temperatures such as catalyst regeneration shall have the frequency shown on the process data sheet.

7.4 Dimensioning Procedure (See 7.1.3)

7.4.1 Vessel/column inside diameters will be specified in increments of 6 inches. Tangent-to-tangent lengths will be specified in increments of 2 inches.

7.4.2 Maximum and normal liquid levels and alarm and shutdown levels shall be specified from bottom tangent line for columns and vertical vessels, and above the bottom of horizontal vessels.

7.4.3 Height of bottom tray above bottom tangent line shall be given for columns.

7.4.4 Minimum tray and manway spacing shall be as follows:

a.

Tower Diameter (in I.D.)	Tray Spacing (in)
36 to 192	24
192 to 328	30
328 and up	36

PROCESS CRITERIA

a. (Continued)

Tray spacing should be greater than the minimum shown above where required for access to column internals, vapor disengaging, nozzle interference or other reasons. Permission to use smaller tray spacing must be obtained from Tri-State.

b. Vessels with trays shall be provided with the following number of manholes:

Number of Trays	Number of Manholes
1 to 25	2
26 to 41	3
42 to 61	4
62 to 80	5

In services in which frequent cleaning is anticipated, the number of manholes shall increase in accordance with severity of service, to a maximum of one for each three trays. The minimum tray spacing at manway locations shall be 30 inches.

7.4.5 Minimum distance from top tray to top tangent shall be 36 inches or as required to accommodate manway, internals or nozzles.

7.4.6 Column trays shall be numbered from bottom to top.

7.4.7 Packed vertical vessels shall have a manhole at the top and bottom of each packed bed for filling and emptying. Suitable sized handholes may be substituted for the bottom manholes. A manhole shall also be provided below the packing support of the lowest bed when the distance from the bottom tangent line to the packing support ring is three feet or greater.

Reactors with top head manholes required for loading catalyst shall be provided with an additional manhole in the shell. This manhole shall be located near the top of the bed for free access at all times.

7.4.8 Vessels shall be provided with a minimum of one manhole in each pressure compartment or two 4-inch diameter handholes or inspection openings when the vessel diameter is less than 30 inches, except that when such vessels contain internals, one end-flange and one 4-inch diameter handhole or inspection opening shall be provided.

PROCESS CRITERIA

7.5 Vessel and Column Internal Details

7.5.1 Removable valve trays shall generally be specified for columns.

7.5.2 Type and size of packing shall be shown on the process flow diagram and vessel sketch.

7.5.3 Internal detail design shall follow Fluor's standard design guides unless specifically designed or modified by the licensor or responsible subcontractor.

7.6 Skirt Height

Required skirt heights above grade will be set by process conditions (i.e. pump NPSH). When skirt height is not influenced by process factors, it will be specified as "Minimum".

7.7 Nozzles and Boots

7.7.1 The following system of nozzle symbols is intended to make it easier to quickly identify nozzles as well as give some hint as to their use. The symbols are to have subscripts if more than one of the same kind are used; that is, for three feeds, use "F_1", "F_2", and "F_3", but if only one feed is used the symbol "F" is all that is required.

A. Inlet
B. Outlet
C. Condensate
D. Drain or Draw-off
E.
F. Feed
G. Level Gage or Gage Glass
H. Handhole
J. Pump Out
K.
L. Level Instrument
M. Manhole
N. Reboiler Connection
P. Pressure Connection
R. Reflux
S. Steam or Sample Connection
T. Thermo Connection
V. Vapor or Vent
W. Relief Valve Connection

Symbols "E" and "K" may be used when none of the others apply. Do NOT use the letters "I", "O", "Q", "U", "X", "Y" or "Z".

7.7.2 All connections shall be flanged with a 1" minimum size. The minimum flange rating for 1" and 1-1/2" connections is 300 psi.

7.7.3 Minimum nozzle size for connected process piping is 1-1/2".

7.7.4 For limitations on velocity through nozzles refer to piping section 13.1.3.

7.7.5 Boots shall be furnished on horizontal vessels in hydrocarbon service which have continuous water drains. Low interface level switches with board mounted alarms will be provided on all boots. Boots shall be sized for at least 7 minutes water flow with 5 minutes residence time below the hydrocarbon/water interface. For elevated vessels water drawoff pots located at grade shall be used instead of vessels boots. The drawoff pot should be connected to the vessel with an oversized line to permit 2-way flow. Size connection line for 0.66 ft/sec maximum.

7.8 Surge Times

Surge time is defined as time from normal level to empty, with no feed and with normal flow out. Surge time may be oppositely defined from normal level to maximum level. In many cases these two surge times will be different. Some typical surge times for use in design are given below:

7.8.1 Feed to Units

	SERVICE	TIME
a.	Wide variations night to day such as gas plants with lines above ground, tank vapor recovery, batch operation.	30-240 min.
b.	Feed comes from another unit under control.	
	(1) Primary unit has poor control	15 min.
	(2) Primary unit has fair control	10 min.
	(3) Primary unit has good control	7-1/2 min.
	(4) Feed comes from storage	5 min.
	(5) Feed goes to multistage high pressure charge pump	10 min.

7.8.2 Compressor K.O. Drum (Base on condensation or entrainment) 4 hrs.

7.8.3 Reflux Accumulators (Based on reflux plus product liquid). Minimum overhead accumulator size shall be 36" I.D. x 80" T-T. — 5 min.

7.9 Insulation

Insulation shall be applied to vessels/columns for heat conservation or safety in accordance with the job insulation specification. Safety insulation shall be applied for operating temperatures of 150°F or above.

7.10 Piping at Vessels

7.10.1 Provision for maintenance blinds should be made at all vessel nozzles. Use spectacle blinds where shutdown and maintenance is frequent and for rigid piping systems where installation of spade would be impractical.

7.10.2 Steamout connections on vessels and columns of 600 Ft^3 or less shall be 1" fitted with a valve and blind flange. Process vessels with larger volumes shall have 1-1/2" connections permanently piped from the steam source. Steamout connections are to be located 6 to 12 inches above the vessel/column bottom.

7.10.3 Pressure safety valve nozzle shall preferably be located in overhead piping, rather than on the vessel. Major factors affecting pressure safety valve nozzle location are discharge destination, accessibility to the valve, and structural support. Column safety valves relieving to flare should generally be downstream of the reflux drum to take advantage of the condenser and liquid knockout provided by the reflux drum. However, the pressure drop between the column and reflux drum should be checked under relieving conditions.

7.10.4 Drain connections shall be placed on the bottom outlet piping from the vessel unless the bottom outlet line is not at the low point of the vessel, in which case a separate drain must be provided. Vessels with internal baffle require special consideration.

7.10.5 Vents shall be placed on the top head of vertical vessels or the top side of horizontal vessels.

7.10.6 Vent and drain nozzle sizes shall be determined from the following schedule:

VESSEL/COLUMN VOLUME	VENT SIZE	DRAIN SIZE
600 ft^3 and less	2 inches	2 inches
600 ft^3 and larger	3 inches	3 inches

7.10.7 Drains from all level gages and level controllers for butane or lighter compounds shall be piped to the flare header.

7.11 Materials

7.11.1 The selection of materials for pressure containing parts shall be based on service, corrosivity, design temperature and pressure. The process design data sheet need specify only the general material category unless a specific material is required.

PROCESS CRITERIA

8.0 HEAT EXCHANGERS

Shell and tube heat exchangers shall be designed in accordance with these criteria:

a. Specification SP-1001-44-1.

   1. TEMA Standards, Sixth Edition, 1978, Class R.

   2. ASME Boiler and Pressure Vessel Code, Section VIII, Division I, 1980 Edition plus Addenda.

   3. API 660, Third Edition, 1976.

b. Specification SP-1001-44-100 covers standard TEMA type shell and tube heat exchangers and steam surface condensers.

Double pipe and multi-tube heat exchangers shall be designed in accordance with these design criteria and Specification SP-1001-44-3 Double Pipe Heat Exchangers which lists Section VIII, Division I of the ASME Boiler and Pressure Vessel Code.

Air cooled heat exchangers shall be designed in accordance with these design criteria and Specification SP-1001-44-2 Air Cooled Heat Exchangers which lists API-661 and Section VIII, Division I of the ASME Boiler and Pressure Vessel Code.

8.1 Definitions

8.1.1 Clean Service shall satisfy the following conditions:

a. Fouling resistance less than or equal to 0.001 Ft^2hr °F/Btu for gas service.

b. Fouling resistance less than 0.001 Ft^2hr °F/Btu for liquid or two-phase service.

c. In some cases, if chemical cleaning is used, services with higher fouling factors than those shown above may be defined as "clean service" if mechanical cleaning is not required.

8.1.2 Fouling Service shall include all services not otherwise defined as "clean service."

8.1.3 Effective outside heat transfer surface is the outside circumferential area of the tubes, including the U-bend portions of U-tubes, less the surface covered by the tubesheets.

PROCESS CRITERIA

8.2 Rating of Exchangers

8.2.1 All shell and tube heat exchangers shall be thermally rated and sized prior to request for quotation by either the contractor or by an independent rating service retained specifically for this purpose. Thermal guarantees of performance in accordance with Fluor specifications shall be obtained from the rating service and/or the selected exchanger Vendor.

8.2.2 Information to be supplied with the thermal rating shall include but not be limited to the following:

a. Total effective heat transfer surface.
b. Tube outside diameter.
c. Tube wall thickness.
d. Tube pitch.
e. Tube length.
f. Number of tubes.
g. Number of passes.
h. Shell pass configuration.
i. Baffle details (orientation and percentage cut).
j. Central baffle spacing.
k. Number and location of shellside nozzle connections.
l. Number and location of tubeside nozzle connections.

NOTE: - Heat release curve is required for condensers and vaporizers if the curve is not linear. The plot should also show the vapor or liquid rates, vapor molecular weight, and liquid gravity.

8.3 General Criteria

8.3.1 Selection of TEMA front and rear head types shall be in accordance with the following table:

PROCESS CRITERIA

8.3.1 (Continued)

TEMA TYPE HEADS (FRONT/REAR)

	Shell Side			
	Clean		Fouled	
	Tube Clean	Side Fouled	Tube Clean	Side Fouled
Non-removable Bundle	B/M,U	A,C/L,N	---	---
Remov. Bundle, ID < 36" (914 mm)	B/U	A/S	B/U	A/S
Remov. Bundle ID > 36" (914 mm)	B/U	A/T	B/U	A/T

High pressure or other design requirements may justify deviation from the guidelines above.

8.3.2 U-tube exchangers are preferred when tightness is essential and the tube side service is considered as nonfouling, e.g. hydrogen service.

8.3.3 Unless otherwise specified, exchangers shall be designed to have water on the tube side.

8.3.4 Kettle type reboilers and U-tube units shall be provided with fixed covers. All other exchangers shall be provided with removable shell covers.

8.3.5 Packed floating heads shall not be used.

8.3.6 Non-removable Bundle exchangers may be used in clean shell side service where a shell expansion joint is not required. In general, the use of shell side expansion joints is discouraged.

8.3.7 The differential expansion between shell and tubes of a fixed tubesheet exchanger shall be based on the controlling metal temperatures, either clean or one side fouled.

8.3.8 The maximum controlling differential temperature between the tube and shell side during operation, startup, shutdown or steamout shall be stated on the data sheet and used to determine the requirement for an expansion joint and tubesheet thickness on a fixed tubesheet heat exchanger.

PROCESS CRITERIA

8.3.9 The use of TEMA Type F shells with removal bundles is discouraged unless there are considerable savings or other design advantages. As a general guideline, limit shell side pressure drop to 7.0 PSI and temperature differential to 250°F.

8.3.10 Maximum shell and tube exchanger sizes shall be as shown below. The Thermal Designer may consider larger sizes to realize economic or design advantages. Larger sizes must be approved by Tri-States.

a. The maximum tube length for straight tubes shall be 20 feet.

b. The maximum bundle diameter for removable bundle exchangers shall be 60 inches. The maximum removable bundle weight shall be 40,000 pounds.

c. There are no weight and diameter limits for fixed nonremovable bundle exchangers.

8.4 Design Pressure

8.4.1 All parts of the tube bundle including floating head shall be designed for either full tube side internal pressure or full shell side external pressure, whichever condition is controlling. Differential pressure shall not be used as design basis unless specified otherwise.

8.4.2 Design pressure for the cooling water side of coolers shall be 150 psig.

8.4.3 Exchanger tube side and shell side design pressure shall be set at the highest of the following conditions as applicable:

a. Shutoff pressure of an upstream pump at normal pump suction pressure if the exchanger can be shut in.

b. Maximum suction pressure of an upstream pump plus normal pump differential pressure.

c.

Operating Pressure,psia	Design Pressure
0 - 150 psia	Operating + 15 psi
150 - 500 psia	Operating + 10%
500 - 1000 psia	Operating + 50 psi
1000 psia +	Operating + 5%
Vacuum	15 psia external

PROCESS CRITERIA

8.5 Design Temperature

8.5.1 The following guidelines shall be used in determining design temperature when operating temperature exceeds 60°F.

a. For operating temperatures of 600°F or less, the design temperature is the operating temperature plus 45°F.

b. For operating temperatures above 600°F, the design temperature is the operating temperature plus 30°F.

c. The operating temperature is defined as the maximum temperature encountered during normal operation, start-up, and shutdown (excluding maloperation).

8.5.2 The following guidelines shall be used in determining design temperature when operating temperature is less than 60°F.

a. For exchangers with fluid temperatures below 60°F, design temperature should be 10°F below the operating temperature.

b. Operating temperature for low temperature service is defined as the minimum temperature encountered during normal operation, start-up, and shutdown (excluding maloperation).

8.5.3 Allowances should be taken for situations in which two fluids of different temperatures are in the process of heat exchange.

8.5.4 Design temperature for the cooling water side of coolers shall be 150°F.

8.6 Tube Size and Pitch Related to Fouling Factors

8.6.1 Exchanger fouling factors shall be per Table 8.1.

8.6.2 Tube size and pitch shall be selected in accordance with Table 8.2.

PROCESS CRITERIA

TABLE 8.1

FOULING FACTORS

Commodity	Factor ($ft^2 hr °F/BTU$)
Nitrogen #	0.001
Air #	0.002
Reformed Gas	0.001
Steam #	0.0005
Boiler Feed Water/Condensate #	0.0005
Lock Gas **	
Gas Liquors (by type) **	
Tar	0.005
Creosote	0.005
Pitch	0.004
Raw Phenol **	
Naphtha	0.001
Hydrogen Sulfide	0.001
Ammonia	0.001
Sulfur (elemental sulfur containing gases)	
Noncondensing	0.001
Condensing	0 01
Raw Gas **	
Carbon Dioxide #	0.001
Town Gas	0.001
Heavy Oil	0.002
Light Oil	0.001
Tail Gas	0.001
Carbonyls ***	0.001
LPG	0.001
Gasoline	0.001
Jet and Diesel Fuel	0.002
Fuel Gas #	0.001
Purified Hydrogen	0.001
Ethylene	0.001
Acetic Acid	0.002
Cooling Water (cooling side of exchangers) #	0.002

**Licensor to specify.
***Includes Alcohols, Ketones and Aldehydes.
#The Fouling Factors indicated in the above table shall be used WHEN IDENTIFIED BY THIS CROSSHATCH MARKING.

All other factors in the table are recommendations ONLY. The respective Process Licensors shall be responsible for the Fouling Factors used in their areas of concern.

TABLE 8.2

TUBE SIZE AND PITCH

Shell Side Service	Tube Side Fouling $Ft^2 {}^\circ F/Btu$	Min. Tube O.D., IN.	Pitch, IN. And Layout
Clean	Up To 0.003 (Incl)	0.75	0.938 (30°)
Clean	Over 0.003	1	1.25 (30°)
Fouling	Up To 0.003 (Incl)	0.75	1 (45°)
Fouling	Over 0.003	1	1.25 (45°)

Exceptions to the above Table are as follows:

a. The pitch and layout guidelines shown above are the minimum starting points for economic design. Larger pitch or different layout patterns may be required to satisfy pressure drop or boiling flux requirements.

b. Triangular pitch may be used with fixed tubesheet exchangers in fouling service.

c. When U-tubes are required to be mechanically cleaned in fouling services, 1 inch minimum diameter tubes shall be used with a minimum bend diameter of four times tube OD. The inside tube rows of U-tubes shall have crossover U-bends to minimize pass lane width.

d. Tube pitch for heavy wall tubes shall not be less than the TEMA recommended values.

8.6.3 Straight tube lengths shall preferably be 20 feet but when necessary they may be other standard lengths of 8, 12, 16, 24, 30 and 40 feet.

8.6.4 The following table specifies bare tube diameters and minimum permissible gauges:

PROCESS CRITERIA

8.6.4 (Continued)

TUBE OD	CARBON STEEL, ALUMINUM AND ALUMINUM ALLOYS	ALLOYS OTHER THAN TITANIUM	TITANIUM
INCHES	BWG (MIN. WALL)	BWG (AVG. WALL)	BWG (MIN. WALL)
0.75	14	14	20
1	12	16	20
1.25/1.5	12	14	20

8.7 Allowable Tubeside and Shellside Velocities and Pressure Drop

8.7.1 As a guideline, the recommended allowable pressure drop per shell for shell and tube exchangers in pumped liquid service shall be as follows:

Viscosity (Cp)	Allowable Δ P Shell Side (psi)	Allowable Δ P Tube Side (psi)
less than 1.0	3.0	5.0
1.0 to 5.0	5.0	7.5
5.0 to 15.0	7.5	10.0
15.0 to 25.0	10.0	15.0
25.0 to 50.0	15.0	25.0
above 50.0	Mechanical Engineering to Specify	

NOTE: Where excess pressure is available, exchanger pressure drop may be specified accordingly.

8.7.2 Allowable pressure drop for air coolers in pumped liquid services shall be as follows:

PROCESS CRITERIA

8.7.2 (Continued)

Viscosity (Cp)	Allowable Δ P Tube Side (psi)
less than 1.0	5.0
1.0 to 10.0	10.0
10.0 to 50.0	25.0
above 50.0	Mechanical Engineering to Specify

8.7.3 Allowable pressure drop for water coolers shall be 10 psi maximum on the cooling water side. For cooling system design allow an additional 5.0 psi for throttling and balancing.

8.7.4 Allowable pressure drop for shell and tube condensers shall be as follows:

System Pressure (psig)	Allowable Δ P Shell Side (psi)
0 to 50	1.5 per shell
50 to 200	3.0 per shell
200 and above	5.0 per shell

8.7.5 Allowable pressure drop for air cooled condensers shall be as follows:

System Pressure (psig)	Allowable Δ P (psi)
Up to 50	1.5
50 to 200	3.0
200 and above	5.0

8.7.6 Cooling Water Velocities

Water velocities for coolers and condensers shall preferably be the values specified below except when pressure drop limitations govern.

8.7.6 (Continued)

Tube Material	Velocity, FPS
Carbon and Low Alloy Steel	3-6
Austenitic Stainless Steel	5-12
Titanium	3-12
Monel	5-12
Incoloy 825, Carpenter 20CB3	5-12

8.7.7 For reboilers, 75% of the available hydrostatic head shall be used for the process side available pressure drop.

8.7.8 Allowable pressure drop for multiple services in series may be specified for the entire train, instead of item by item.

8.8 Reboiler Selection

8.8.1 Reboiler selection shall be made from the following types:

a. Kettle
b. Vertical thermosyphon
c. Horizontal thermosyphon

8.8.2 Reboiler selection shall be made to satisfy as many of the points on Table 8.3 as possible. Additional considerations include:

a. Equipment arrangement
b. Maintenance facilities

8.8.3 Surge Time

Surge time is a factor to consider when level controlled flow from a kettle type reboiler. A minimum of 2 minutes in the level control range is usually necessary for stable control. More surge time may be necessary depending on destination and required stability of output flow.

If the volume cannot be economically accommodated by the exchanger, provisions should be made in an external surge drum. For kettle reboilers, the column bottom can often be used for this purpose.

8.8.4 Horizontal thermosiphons shall have more than one inlet and outlet nozzle if the bundle length to diameter ratio is greater than 5. Even with multiple nozzles, very long tube lengths with small shell diameters are not recommended because of potential maldistribution and excessive piping cost. Maximum tube length shall be in accordance with the following table:

Shell Diameter, In.	Maximum Tube Length, Ft.
12-18	8
19-29	12
30 and Larger	16

8.9 Shell Side Versus Tube Side Service

8.9.1 Tube side/shell side selection shall be made to satisfy as many as possible of the following points:

Service	Shell Side	Tube Side
Cooling Water		X
Condensing Vapors	X	
Lower Allowable Δ P	X	
Larger FLow with Similar Properties	X	
High Pressure Fluids		X
Corrosive Fluids/Alloy Construction		X
High Fouling Factors		X

8.10 Exchanger Approach Temperatures

8.10.1 For exchanging heat in shell and tube exchangers, there are guidelines that can be observed in setting the approach temperature. These guidelines do not apply to all cases. For example, there may be cases where there is no temperature cross and selecting an optimum approach temperature may depend on control requirements or other criteria. However, where the maximum economic heat transfer is desired, the guidelines are as follows:

Reboilers	Minimum Approach Temperature, °F
Steam	30
Hot Oil Loop	40

PROCESS CRITERIA

TABLE 8.3

REBOILER SELECTION

	Kettle	Horizontal Once-Thru	Horizontal Thermosyphon	Vertical Thermosyphon
Maximum % Vaporized	Unlimited (30 to 90% Normal)	60%	25%	25%
Allowable Fouling Factor	0.001	0.001	Unlimited	Unlimited
Bottoms Require Pumping	Kettle and column must be elevated	Column only elevated	Column only elevated	Column only elevated
Bottoms Do Not Require Pumping	Neither column or reboiler need be elevated	Neither column or reboiler need be elevated	Neither column or reboiler need be elevated	Neither usually must be elevated
MTD	Highest	Highest	Lowest	Lowest
Surge Capacity	Limited within kettle	Within column	Within column	Within column
Typical Pressure Drop	0.7 psi	1.5 psi	1.5 psi	1.5 psi
Column Internals	Simplest	Simplest	Require Baffling	Require Baffling
Space Requirement	Highest	In-between	In-between	Lowest

8.10.1 (Continued)

When hot oil loop is not temperature controlled, e.g., when heat medium is pump around reflux from a column, extra surface and/or circulation should be specified.

8.11 Breakpoint Between Air and Water Cooling

8.11.1 The following items should be considered when selecting air or water cooling:

a. Inlet temperature/outlet temperature
b. Total duty
c. Pour point of material
d. Viscosity of material
e. Air temperature
f. Water temperature
g. Plot plan space availability

8.11.2 The break point between air and water cooling will be determined by Fluor. The cooling water makeup may be the biotreated gas liquor which must be vaporized to prevent accumulation of this liquor. Details of the cooling water makeup will be developed as a part of an overall plant water management scheme.

8.12 Air Cooled Exchangers

8.12.1 Tubeside fouling factors shall be the same as specified for shell and tube exchangers (Table 8.1).

8.12.2 Air side fouling factors shall be assumed negligible.

8.12.3 The design inlet air temperature shall be 88°F. Minimum design temperature of -15°F will be considered for process reasons but not for winterization.

8.13 Piping at Exchangers

8.13.1 All heat exchangers, coolers, condensers, and reboilers that can be removed from service without a unit shutdown shall have block valves and isolating spectacle blinds provided on, or immediately adjacent to, all inlets and outlets. Heat exchangers, coolers, condensers, and reboilers that require a unit shutdown for isolation need not have block valves.

PROCESS CRITERIA

8.13.2 Air coolers and condensers shall also have isolation block valves and spectacle blinds only if a unit shutdown is not required for isolation. Individual cooler sections in fouling service (0.002 $ft^2hr°F/BTU$ or greater fouling factor) shall have block valves and spectacle blinds provided at the inlet and outlet of each section.

8.13.3 Unless venting and draining can be done via other equipment, shell and channel side piping shall be provided with a vent and drain connection. Vent and drain valves shall be 3/4" minimum.

8.13.4 For coolers and condensers, connections for chemical cleaning shall be provided where specifically requested or agreed with Tri-State.

8.14 Plate Heat Exchangers

8.14.1 Plate heat exchangers shall be considered if the following conditions exist:

a. Low LMTD.

b. Temperature crossovers (true countercurrent flow required).

c. Corrosive services requiring alloy materials of construction.

d. Fouling services.

8.14.2 The design pressure and temperature limits for plate heat exchangers shall be 300 psig and 390°F respectively.

8.15 Brazed Aluminum Core Heat Exchangers

8.15.1 Brazed aluminum core heat exchangers shall be considered if any or all of the following criteria are met:

a. Operating temperatures are -50°F and below (nonfouling services).

b. Multi-stream heat transfer in a single unit is required.

c. Space limitations exist.

8.15.2 The design pressure limit for brazed aluminum core heat exchangers shall be 1100 psig.

PROCESS CRITERIA

8.16 Steam Surface Condensers

8.16.1 Steam surface condensers shall be in accordance with HEI Standards and SP-1001-44-5.

8.16.2 Tube material shall be carbon steel.

8.16.3 Cleanliness factor for carbon steel tubes shall be 65%.

8.16.4 For critical services and for services that do not involve parallel streams, divided water boxes shall be provided.

8.17 Slurry Handling

8.17.1 Slurry services shall be routed through the tube side of the exchanger.

8.17.2 Minimum tube size shall be 1 inch O.D. at 12 BWG wall thickness.

8.17.3 Velocity limits for cycle oil containing catalyst fines shall be as listed below. The optimum velocity is 5.75 ft/sec.

	Velocity, FPS	
	Maximum	Minimum
Straight Tube	7.0	3.75
U-Tube	5.75	3.75

8.17.4 Straight tube construction is recommended.

8.17.5 Horizontal units shall be designed with horizontal or downflow of slurry through the bundle.

8.18 HF Acid/Lethal Service

To minimize chances of acid leakage into the process area, exchanger design shall provide as few joint closures as is practical, (i.e. U-tubes, removable TEMA "C" stationary head, etc.)

8.19 Pulsating Flow on Shell Side

8.19.1 Maximum unsupported tube length for vapor or 2-phase flow shall be 36 inches.

8.19.2 Provide impingement plate.

PROCESS CRITERIA

8.19.3 Provide distribution belt or design as required for a maximum pV^2 of 500 lbs/ft-sec^2 into the bundle.

PROCESS CRITERIA

9.0 PUMPS

Process centrifugal pumps shall be specified and designed in accordance with API-610, Fifth Edition, "Centrifugal Pumps for General Refinery Services" as modified by Fluor SP-1001-46-1.

9.1 Rated Capacity

9.1.1 Pump rated flow capacity shall be set in accordance with the following table:

Service	Rated Capacity over Normal, %	
	Flow Control	Level or Temperature Control
Unit Feed	5	10
Unit Product	10	15
Feed Booster	10	15
Overhead Reflux	15	20
Pump Around Reflux	20	20
Reboiler Feed	15	20
Boiler Feed	--	10 *

*Above rated boiler capacity.

For pumps in intermittent service (e.g. product shipment), only the rated capacity need be specified.

9.1.2 All pumps in continuous service shall be either 100% spared or common spared. Common spare will be specified only if fluid characteristics, capacity and power requirements are similar. In large capacity services where parallel pumps are required, a common spare will also be specified.

9.2 NPSH Calculation

Calculation of NPSH shall be based on the following:

9.2.1 For subcooled liquids, the source pressure shall be the minimum normal operating pressure and the vapor pressure shall be at the maximum normal process temperature.

9.2.2 The suction line losses shall be based on rated flow capacity of the pump. Pressure drop through the permanent strainer shall be based on 50% clogging.

PROCESS CRITERIA

9.2.3 Static head shall be measured from the bottom of the horizontal drums and from the bottom tangent line of columns or vessels with bottom drawoffs, and from the elevation of the outlet nozzle for side drawoffs, to the centerline of horizontal pumps, or the outlet nozzle of vertical pumps.

9.2.4 For NPSHA calculations, assume the pump centerline for horizontal pumps to be 3 ft above the top of the foundation unless otherwise stated. The reference point to be used in determining the NPSH required for double case vertical pumps shall be the suction nozzle horizontal centerline.

9.2.5 No overplus shall be added to the calculated NPSH available.

9.2.6 The calculated NPSH available shall be at least 10% or 18 inches greater than the NPSH required by the selected pump, whichever is greater.

9.3 Pressure Casing Design

9.3.1 Centrifugal pump casings shall be designed for a pressure equal to or greater than maximum discharge pressure at pumping temperature with maximum impeller installed.

9.3.2 Positive displacement pumps shall be designed to withstand either the stalling pressure or shall be provided with a discharge relief valve which shall not be set higher than the casing design pressure.

9.3.3 Refer to Paragraph 9.7.5 for guideline to specify associated piping design conditions.

9.4 Minimum Flow

9.4.1 Normally all pumps shall be suitable for continuous operation for a flow of 30% of rated capacity. If flow conditions necessitate flow for less than 30%, then minimum flow provisions for centrifugal pumps shall consist of a line from the pump discharge to the suction source. Minimum flow required shall be based on manufacturer's recommendations. Minimum flow bypasses shall be used in the following services:

a. Multistage pumps.

b. Boiler feedwater pumps.

PROCESS CRITERIA

9.4.1 (Continued)

c. Where there is a possibility of a no-flow condition occurring in a pump discharge system.

d. High speed in-line pumps (Sundyne).

9.5 High Speed In-Line Pumps

High speed in-line pumps are preferred to reciprocating pumps for low capacity, high differential pressure services in most cases.

9.6 Injection Pumps

Injection pumps in acid, chemical and caustic service shall be capable of flow control by adjusting the stroke while the pump is in operation.

9.7 Pump Piping

9.7.1 Each centrifugal pump shall have a suction block valve, and discharge check and block valves, all of which shall be located as close to the pump nozzle as possible.

9.7.2 Special consideration should be given to sizing pump suction and discharge block and check valves. Some factors to take into consideraion are the following:

a. Pump nozzles are almost always smaller than the piping because different criteria are used in their sizing.

b. Smaller than line size valves have several advantages, i.e. economy, flexibility, and reduced congestion around the pump. The larger the line size, the more important these advantages become.

c. Process requirements have to be balanced against the above advantages. NPSH requirement is generally the governing criteria for pump suction, and must not be jeopardized by size reductions. On the discharge side, the pressure drop through the check valve becomes a factor to consider.

9.7.3 Velocity is the most convenient criteria for sizing pump valves. It can be calculated before the pump is purchased, and checked later, after the pump nozzle sizes are known. The following criteria may be used as a guide based on maximum pump design flow:

9.7.3 (Continued)

a. For line sizes 2" and smaller, use line size valves.

b. For suction lines 3" and above:

1. When NPSH is tight or governing, size for 4 fps maximum velocity.

2. When NPSH is not governing, suction valve may be sized for velocity up to 8 fps but suction valve size should never be less than the suction nozzle on the pump.

c. Discharge lines 3" and above, size for 15 fps maximum velocity.

These are general guides applicable to most situations but each case should be considered on its own merits.

9.7.4 All pumps shall have strainers installed on the pump side of the suction valve. Permanent strainers with a flanged side entry for screen removal (i.e., constructed such that the screen can be removed for cleaning without disturbing the suction piping or removing a spool) shall be installed in the suction lines to dirty service pumps, process solvent circulating pumps, pumps with a suction temperature greater than 300°F, cold insulated pumps, and pumps with RTJ flanges. When steam turbines are used, inlet piping to the turbine shall contain permanent strainers.

9.7.5 a. The design pressure of the piping and equipment not protected by relief valves on the discharge side of a centrifugal pump shall be specified for the greater of the following alternatives.

1. The normal suction pressure plus the shutoff differential head of the pump.

2. The maximum suction pressure plus the normal flow differential head of the pump.

b. Since piping is normally rated before pump curves are available, it is necessary to estimate shutoff pressure. The following rules shall be used as a guide.

1. Straight centrifugal pump with medium and high heads, 25 percent shall be added to the normal specified differential pressure.

9.7.5 b. (Continued)

2. For very low head centrifugal pumps, 35 percent shall be added to the differential pressure.

3. For axial flow pumps, 80 percent shall be added or use a relief valve.

c. The pump suction block valve and all pipe, fittings, strainers, and equipment downstream of it shall have a higher line class than the pump suction piping upstream of the block valve, if the pump discharge design pressure is more than 1.33 times the pump design suction pressure.

d. For positive displacement pumps, the discharge piping shall be designed for either the downstream relief valve setting or the casing design pressure.

9.7.6 Vent and drain connections for pumps shall be in accordance with Section 13 (Piping). The requirements listed below apply specifically to pumps.

a. Casing vents and drains for pumps in non-volatile services shall be piped to the sewer.

b. Casing vents for pumps in services handling materials near the auto-ignition point shall either be piped to a cooler and from the cooler to a conservation sewer or shall be discharged to a closed system.

c. Casing vents for pumps in hydrocarbon services handling C_4 fractions and lighter shall discharge to a closed system or flare.

d. Vents and drains in services releasing lethal vapors shall discharge to a closed system.

e. In abrasive services, valved vent and drain connections shall be located in adjacent piping and not in pump casings and liquid end cylinders.

f. Vent and drain connections shall be 3/4 inch nominal pipe size minimum.

g. In vacuum service, pump vent connections shall be permanently piped to the vapor space of the suction vessel.

PROCESS CRITERIA

9.7.7 Sight flow indicators shall be provided on cooling water lines to pump jackets.

9.7.8 3/4 inch warm-up bypasses shall be provided on all pumps that operate above 300°F or are in high viscosity service.

9.8 Materials

Material class designation of pumps shall normally be in accordance with API-610.

PROCESS CRITERIA

10.0 COMPRESSORS

Process centrifugal compressors shall be specified and designed in accordance with API-617, Fourth Edition, 1979, "Centrifugal Compressors for General Refinery Services" as modified by Fluor SP-1001-43-1. Process reciprocating compressors shall be specified and designed in accordance with API-618, Second Edition of July 1974, "Reciprocating Compressors for General Refinery Services" as modified by Fluor SP-1001-43-4 and SP-1001-43-5. In addition this section covers the general process criteria for the different types of compressors.

10.1 Compressors Selection and Rating

10.1.1 For all compressors the rated capacity shall be a minimum of 10 percent greater than the maximum material balance flow.

10.1.2 Approximate compressor calculations shall be performed for each compressor. Primary objectives of these calculations are:

a. Estimation of power requirement.

b. Estimation of temperature rise.

c. Approximate number of stages.

d. Estimation of utility requirements.

e. Establishment of control requirements.

10.1.3 Centrifugal compressors will be specified for high reliability and, in general, will not be spared.

10.1.4 Small reciprocating compressors in critical services will be 100 percent spared.

10.1.5 Large reciprocating compressors may be either 100 percent spared (two machines), or 50 percent spared (three machines).

The choice will depend on the particular service and the economics involved.

10.2 Mode of Control

10.2.1 Centrifugal Compressors

a. Turbine driven compressors may be rate controlled by adjusting turbine speed within limits allowed by the vendor, or by bypassing amount of flow as required.

PROCESS CRITERIA

10.2.1 (Continued)

b. Motor driven compressors may be rate controlled by:

1. Suction throttling.

2. Bypassing the amount of flow as required.

3. A combination of bypass and suction throttling.

4. Discharge throttling (not preferred).

5. Inlet guide vanes (not preferred).

c. If required, provisions shall be made for compressor bypassing at start-up.

d. Provision shall be made for surge protection.

10.2.2 Reciprocating Compressors

a. Reciprocating compressors that are not motor driven may, if necessary, be controlled by adjusting speed within limits allowed by the vendor. However, this is not the preferred mode of control.

b. For constant speed machines, bypass control may be used for less than rated compressor output. The bypass cooler system will be rated for 100 percent of rated compressor flow.

c. Inlet valve unloaders may be used for control to avoid horsepower waste. Clearance pocket unloading may also be used to control compressor throughput. They may be fixed and may be automatically or manually operated. Position indicators for these controls are required.

d. Recirculation bypass control, clearance pocket unloading, and inlet valve unloaders may be used in combinations for various capacity changes.

e. Small compressors in service such as air supply, where sufficient receiver capacity is provided, may be controlled by automatic start-stop or constant speed unloading.

PROCESS CRITERIA

10.2.2 (Continued)

f. Provisions shall be made for compressor unloading or bypassing at start-up.

g. Suction throttling is not to be used.

10.3 Performance Curves (Centrifugal Compressors)

10.3.1 The following process information shall be provided by compressor vendors:

a. Calculated power.

b. Accurate statement of discharge temperature.

c. Speed of compressor at design point.

d. Performance curves showing discharge pressure and temperature, brake horsepower, polytropic head and efficiency as a function of inlet volume. This shall include curves at 80, 90, 95, 100 and 105 percent of rated speed. Estimated surge points shall be shown at each speed. The variable speed data does not pertain to units on electric motor drive. Quandrant curves are required on all variable MW processes.

e. For variable speed drivers, characteristics shall be given at 80, 90, 95, 100 and 105 percent of rated speed.

10.4 Compressor Suction K.O. Drum

10.4.1 All reciprocating compressors shall be provided with K.O. drums in the suction lines as close as possible to the compressor. Discharge K.O. drums shall be provided only when required by the process. K.O. drums shall be sized to retain the calculated condensation and entrainment that will occur during four hours of operation. Inlet lines are to be steam traced with no pockets. Demister pads to be reinforced for pulsation protection.

10.4.2 Centrifugal compressors generally require suction K.O. drums. However, in certain cases it may be possible to take suction from a process vessel performing another function. Generally this vessel should be close to the compressor and have the same type of operating safeguards as for a special purpose K.O. drum. Demister pads to be reinforced for pulsation protection.

PROCESS CRITERIA

10.4.3 With vertical knockout drums, compressors shall be controlled to shut off if the knockout drum liquid level reaches 90 percent of the height of the bottom of the inlet nozzle. An alarm shall be activated if the knockout drum liquid level reaches 67 percent of the height of the bottom of the inlet nozzle.

10.4.4 With horizontal knockout drums, compressors shall be controlled to shut off if the knockout drum liquid level reaches 50 percent of the vessel diameter. An alarm shall be activated if the knockout drum liquid level reaches 25 percent of the vessel diameter.

10.4.5 The use of reinforced demisters will be considered on an individual basis.

10.5 Compressor Cooling Water

10.5.1 The compressor lube oil water coolers will have higher pressure on lube oil system side than the cooling water side.

10.5.2 Water side fouling factors shall be 0.002 $ft^2hr°F/BTU$. Oil side fouling factors shall be 0.001 $ft^2hr°F/BTU$.

10.5.3 Maximum allowable cooling water temperature rise shall be 15°F in lube oil coolers, and 10°F in compressor cylinder jackets.

10.5.4 Cylinder cooling water inlet temperature shall be at least 15°F above the inlet gas temperature.

10.6 Piping At Compressors

10.6.1 Compressor suction lines shall be heat traced and insulated if the process gas is within 25°F of its dew point at suction conditions. Traps in the suction lines should be avoided.

10.6.2 All compressor suction piping including pulsation bottles shall have the same pressure rating as the discharge piping back to and including the first suction block valve. This may be waived if the suction piping is protected properly by a relief valve.

10.6.3 All compressor piping shall have adequate valved drains, piped to a safe disposal area.

PROCESS CRITERIA

10.6.4 Compressors shall have inlet suction strainers located as close as practical (not to interfere with flow) with breakout flanges and Δ P indicators.

10.6.5 Spectacle blinds shall be provided on compressor side at the main isolating valves.

If the material being handled is toxic, flammable, or otherwise hazardous, proper purge facilities shall be provided. Consideration in these cases shall also be given to the provision of double-block-bleeder arrangements on the lines so that minor maintenance work may be performed without the necessity of installing the spectacle blinds.

PROCESS CRITERIA

11.0 FIRED HEATERS REFERENCE SP-1001-45-1

This criteria gives general guidelines for the process design of fired heaters. Fired heaters shall be designed in accordance with these design criteria and specification SP-1001-45-1.

11.1 Heater Selection

The type of furnace selected shall be suitable for the service conditions, the fuel specified, and the fuel efficiency.

11.1.1 Steam superheater and boiler coils shall be in accordance with Section I of the ASME Boiler and Pressure Vessel Code.

11.2 Heater Design

11.2.1 Heater type selection generally will depend on the service. Table 11.2 gives general guidelines for heater type selection based on whether the service is coking or noncoking.

11.2.2 Burners and fuels shall be specified to permit operation at up to 125 percent of design heat release. They shall also operate at air rates 10 percent higher than the 20 percent and 30 percent Excess air specified for Fuel Gas and Fuel Oil respectively.

11.2.3 Individual economic and environmental constraints shall determine whether natural or forced draft furnaces will be used.

11.2.4 Fired heater average flux densities, minimum coil pressure drops, and mass velocities shall be as shown in Table 11.1.

11.2.5 Fired reboiler shall be designed for a maximum of 60 percent by weight vaporization.

11.2.6 Surge volume for fired reboiler circulating bottoms shall be 17.5 ft^3/hr per million BTU.

11.2.7 Fired heater duty shall generally be designed for continuous service at 10 percent above the normally expected process operating duty. This shall be defined as design flow at lower inlet temperature.

11.2.8 Burner minimum operating range is 30 percent of design heat release.

PROCESS CRITERIA

TABLE 11.1

HEATER DESIGN GUIDE

Service	Average Flux Density BTU/hr ft^2	Pressure Drop (psi)	Mass Velocity lb/ft^2-sec
Naphtha/Kerosine Light Oil	12,000	30	160
Heavy Oil	10,000	30	180
Pitch	7,000	100	220

TABLE 11.2

HEATER TYPE SELECTION GUIDE

	Horizontal		Vertical	
Service	Individual Pass Control	Multi Pass Control	Individual Pass Control	Multi Pass Control
NONCOKING				
a. Single Phase		X		X
b. Vaporizing		X		X
c. Hydrotreater		X	X	
d. Hydrogen				X
COKING				
a. Single		X		X
b. Vaporizing	X		X	
c. Hydrotreater (1)	X		X	

(1) H_2 Added to Feed Oil

PROCESS CRITERIA

11.3 Allowable Film Temperatures, Decoking Requirements

11.3.1 For coking service, maximum oil film temperature should not be more than 50°F above the maximum bulk oil temperature.

11.3.2 For coking service, permanent steam-air decoking systems shall be provided. Two direction steam-air decoking manifolds shall be provided. A decoking pit or drum shall be provided to receive the decoking effluent.

11.3.3 For temperature sensitive process streams, the heater design shall not have an excessive temperature peak prior to the heater outlet. This peak should generally not exceed 5°F for vacuum or coking services.

11.4 Coil Design Pressure and Temperature

11.4.1 Coil design pressure shall be the maximum pressure determined by the upstream source (i.e., shutoff pressure).

11.5 Fuel Systems

11.5.1 Heat release for process heaters shall be based on the LHV of the fuel.

11.5.2 Provisions shall be made so that no condensation occurs in gaseous fuel lines.

11.5.3 Fuel oil and/or gas analysis, pressure and temperature shall be supplied with heater specification. Metals and sulfur shall also be included in the fuel oil analysis.

11.5.4 Atomizing steam shall be at least 100 psig at the burner valve and at least 30 psig above the fuel oil pressure.

11.5.5 Atomizing steam lines will be sized for 1.0 lb steam/lb oil.

11.5.6 Steam quality shall be dry and preferably have at least 50°F superheat. Adequate provisions shall be made for draining and blowing off steam lines.

11.5.7 For fuel containing sulfur, the minimum allowable convection metal temperature is 350°F.

PROCESS CRITERIA

11.6 Snuffing Steam

11.6.1 Snuffing steam rate to the firebox shall be 0.75 lb/hr-ft^3 firebox volume.

11.6.2 Snuffing steam rate to header boxes shall also be designed for .75 lb/hr ft^3 of header box volume.

11.6.3 Snuffing steam rate to the convection section should be designed for 30 lb/hr ft^3 of duct or stack area.

11.6.4 Snuffing steam supply pressure will be 60 psig.

11.7 Piping at Fired Heaters

11.7.1 Use of unsymmetrical piping at furnace multipass inlets and outlets should be minimized.

11.7.2 Fuel gas pilots shall be supplied on fuel oil fired heaters. Fuel gas fired heaters shall have minimum flow bypasses around the fuel gas control valves. The minimum flow bypasses shall have a pressure controller set for the minimum flow required to keep the burner lit. All drains from the fuel gas lines must be either piped to flare or ground level away from heater.

11.7.3 The burners shall be designed for firing refinery gas or fuel oil. Fuel characteristics are to be shown on the data sheet. Where both gas and liquid fuels are specified, burners of the combination type shall be capable of burning any of the specified fuels separately.

11.7.4 The smothering system shall have a header located at a safe distance from the furnace for providing smothering steam to various furnace sections. Smothering steam for firebox, header boxes and convection section shall be three separate laterals. Each line from the remote headers shall have a block valve a minimum of 50 ft from the furnace at grade level. A 1/4" drain hole shall be installed at the low point downstream of the block valve in each steam smothering line. The header supplying the smothering steam lines shall be alive during operation of the heater, and shall be drained through a steam trap.

PROCESS CRITERIA

11.7.5 The service steam header is intended for steaming out purposes. It shall have a block valve at the steam main that must always be kept active even when the unit is down. The service steam header shall have connections to individual furnace feed lines in oil service. The steam lines shall be provided with a bleeder located between the check valve and the second block valve and shall be connected directly downstream of the control valves.

11.7.6 When purging is required, furnace coils shall be served by piping permanently connected to each coil inlet and to a source of steam.

11.7.7 All burners shall be hooked up in such a way that they can either be blanked off or disconnected when not in use.

11.7.8 The fuel system, both liquid fuel and fuel gas, for each furnace shall have a block valve and a spectacle blind in the main supply line. These should be remote from heaters and accessible for rapid operation in an emergency.

11.7.9 The liquid fuel and fuel gas control stations shall be located on the operating platform. The block valves in the liquid fuel and fuel gas supply lines to the burners and the valves for steaming out of these lines shall be located close to the furnace observation doors.

11.7.10 At the extreme end of the main liquid fuel supply line to the furnace, an orifice cock shall be installed so as to maintain a constant fuel supply pressure and to ensure a permanent small flow in the fuel return line. This cock shall never be installed in the fuel lines to burners. The fuel return line shall be routed to the liquid fuel source.

11.7.11 Heavy fuel oil supply shall be arranged for continuous circulation of the oil through the headers.

11.7.12 Fuel gas supply piping shall be arranged to produce equal distribution of flow and sloped for condensate drainage.

PROCESS CRITERIA

12.0 CONTROL VALVES AND RELIEF VALVES

12.1 Control Valve Sizing

Sufficient pressure drop must be allowed for control valves to obtain good regulation, maintain flow characteristics, and obtain desired maximum capacity. It is important that a valve pressure drop allowance be made in specifying pumps, blowers, compressors and reboilers. The following minimum control valve pressure drops are for normal applications.

A check should be made for hydrostatic head, but this should not be included in the variable system pressure drop.

12.1.1 At normal design rate, 50 percent of the variable system pressure drop exclusive of the control valve, or in other words, one-third of the total variable system drop including the control valve should be allowed. On light hydrocarbon products to storage that are stored under product vapor pressure, the valve pressure drop shall be based on downstream vapor pressure at maximum ambient temperature of 108°F.

12.1.2 For reflux, charge and recycle pumps, 15 psi minimum or one-third of the total variable system pressure drop, whichever is greater, should be allowed. The pump curve should be reviewed to make sure that enough pressure drop has been built into the pump head for the control valve to operate at the maximum pump design rate. The pressure drop that has been allowed should be equal to a minimum of 15 percent of the variable system drop at the maximum pump design rate or 10 psi whichever is greater.

12.1.3 For control valves in the steam line to reboilers, the allowable pressure drop shall be 5 percent to 10 percent of the initial absolute steam pressure. When operating with low pressure steam of 30 psig or less, a minimum drop of 5 psi shall be used.

12.1.4 For large variable system pressure drops, 150 psi or more, such as may be encountered with heaters or furnaces, the minimum allowable pressure drop shall be 15 percent of the variable system pressure drop exclusive of the control valve.

12.1.5 For automatic pump startup where the control valve is in the steam line to the pump driver, the control valve shall be line size. The resulting pressure drop is not a factor for sizing and should be 5 psi or less.

PROCESS CRITERIA

12.1.6 Control valves will be sized for a maximum capacity of 1.3 times the normal flow or 1.1 times the maximum design flow, whichever is greater.

12.2 Control Valve Piping

The following criteria shall generally be used in the piping and valving of control valves.

12.2.1 Control valves in flashing service shall be placed as close as practical to the destination of the stream. Consideration shall be given to avoiding traps in the piping downstream of flashing control valves. Control valves in flashing service shall be so noted on the mechanical flow diagrams. Where possible, angle valves discharging directly into a vessel vapor space should be used. If it is not possible to use an angle valve discharging directly into a vessel, the downstream piping shall be sized such that cavitation does not take place.

12.2.2 The use of bypass valves around a control value must be justified in terms of safe operability. If it is necessary to use a bypass valve then the process variables must have local readouts visible at the valve location. If control valve operation is sufficiently critical, consideration should be given to a parallel, standby control valve.

12.2.3 Bypass valves shall have at least the same C_v as the control valve. Maximum C_v for the bypass valve shall be twice the C_v of the control valve. Bypass valve shall be globe up to and including 4" size.

12.2.4 Control valve block valves shall be at least one size larger than the control valve but not larger than line size.

12.2.5 Spools shall be provided between control valves and block valves. Valved 3/4" drains shall be provided on the isolatable spool upstream of control valves.

PROCESS CRITERIA

12.3 Relief Valves/Relief System

Relief systems shall be designed in accordance with ASME Pressure Vessel Code, Section VIII, Division I, ANSI B31.3, API RP-520 (Part 1), API RP-521 (Sections 1, 2, and 3). Simultaneous cases for maximum relief discharge are defined in Section 12.4. A flow diagram shall be prepared for each applicable case. Fluor's relief header optimization computer program shall be used to determine the optimum relief header size that does not violate allowable back pressures at relief valves. Advantages of diaphragm valves in low pressure services shall be considered. The Process Egineer shall also consider the economics and job impact of raising design pressure of limiting low pressure equipment. Heat and material balance calculations shall be the basis for the determination of required relief loads at individual relief valves. A relief valve design data sheet will be prepared for each PSV. The work will be performed during phase II of the project.

12.4 Simultaneous Cases for Maximum Relief Discharge

Maximum discharge rate to the relief system shall be considered from the following cases:

12.4.1 Operator error

a. Blocked discharge

b. Inadvertent opening of valves

12.4.2 Utilities failure

a. Cooling water failure

b. Electric power failure

c. Steam/boiler feedwater failure

d. Loss of fuel

e. Instrument air failure

12.4.3 Local equipment/operation failure

a. Reflux failure

b. Reboiler - abnormal heat input

c. Heat exchanger tube failure

12.4.3 (Continued)

d. Condenser failure

e. Fan failure on air cooled condensers

f. Accumulation of noncondensibles

g. Loss of absorbent flow

h. Automatic process control failure

i. Loss of refrigeration

12.4.4 External fire

12.5 Venting to Atmosphere or to Closed System

12.5.1 Relief and safety valves shall discharge to atmosphere when the valve releases nonhazardous vapors, liquids or hydrocarbon liquids, hydrocarbon vapors or mixtures of hydrocarbon and other vapors such as steam, with a molecular mass of 30 and less, except as modified below. Bonnet vents of back pressure type relief valves may discharge to atmosphere.

12.5.2 Relief and safety valves shall discharge to a closed system when the valves release one of the following:

a. Noxious vapors and liquids.

b. Hydrocarbon liquids, hydrocarbon vapors or mixtures of hydrocarbons and other vapors such as steam with a molecular mass greater than 30.

c. Hydrocarbon liquids, hydrocarbon vapors or mixtures of hydrocarbon and other vapors such as steam, irrespective of molecular mass, when released in process areas.

12.5.3 The outlet of relief and safety valves discharging vapor to the atmosphere in hydrocarbon service shall be located at least 10 ft above the highest working level or building roof within a radius of 35 ft. Adequate safety provision shall be made so that no unusual hazards are created at grade or other main operating levels due to the presence of combustible vapor mixtures, atmospheric pollution or heat radiation as a result of ignition of the emission from the relief valves at the outlet point.

12.5.4 a. Relief valves on the discharge of positive displacement pumps may discharge to the pump suction or to the suction source.

b. Thermal relief valves may discharge to an open drainage system or to a safe location.

c. Cold liquid relief valves may discharge to a large accumulator.

12.5.5 Heat exchangers shall be protected against internal failure due to a ruptured tube under certain conditions.

See SP-1001-70-1, for the full details pertaining to this item.

12.6 Relief Valve Set Pressure

Relief valves shall be set to open at or below the design pressure of the system or equipment to be protected.

12.7 Relief Valve Locations

12.7.1 Equipment that is connected together by a system of adequate piping not containing valves which can isolate any item may be considered as one unit in applying a relief valve or valves. If the equipment is isolated from one another by valves in the connecting piping, then each equipment shall be considered as a unit with its own relief valve or valves. The metallurgical flow diagram shall be considered when determining where relief valves are required.

12.7.2 Relief valves shall be supplied between block valves on the cold side of heat exchangers which can be blocked in. For exchangers in cooling water service, the relief device shall be located on the cooling water inlet line, which is the clean side.

12.7.3 Relief valves shall be provided for closed piping systems exposed to heating.

12.7.4 Relief valves shall be provided for the discharge of all reciprocating compressors on compressor side of block valve.

12.7.5 Relief valves shall be provided for the discharge of positive displacement pumps on pump side of block valve, unless internal relief valve is provided.

12.7.6 Relief valves shall be provided between the block valves on the low pressure side of heat exchangers, or other equipment subject to internal leaks or tube failures.

12.7.7 Piping systems for pumps, compressors, and blowers shall be provided with relief valves or an automatic shutdown device when the casing design pressure may be exceeded. Over pressure by fire shall not be considered.

If a noncondensing turbine is installed to start automatically, full relief capacity is required and shall be sized in accordance with NEMA Recommended Standards Publication No. SM-21 and 22.

12.7.8 For vessels in vapor service, relief valves shall be installed on the piping to or from the vessels. The pressure drop in the inlet piping to the relief valve shall not exceed 3 percent of the allowable pressure at design relief capacity.

12.7.9 For vessels in vapor and/or liquid service, relief valves shall be located to avoid two-phase flow.

12.7.10 For relief protection from a single source requiring multiple valves, one of the valves will be set at or below the design pressure and the remainder shall be staggered up to a maximum of 105 percent of design pressure.

12.8 Slope of the Relief Header

12.8.1 Relief system piping shall be self-draining toward the discharge end. Where pocketing of discharge lines cannot be avoided, piping shall be traced and provided with suitable drip legs, condensate pots, and drains.

12.8.2 A slope of 0.2 percent of run is desirable for all laterals and headers, taking into account piping deflections between supports.

12.8.3 Laterals receiving two-phase or liquid relief shall be equipped with a knockout drum with a liquid hold-up time of 10-30 minutes. This should be equipped with a gauge glass, alarm and drain.

12.8.4 Traps or other devices with operating mechanisms shall not be used.

PROCESS CRITERIA

12.8.5 Laterals shall enter the header from above. If unavoidable, laterals approaching from below the header shall rise continuously to the header entry point.

12.9 Thermal Relief

12.9.1 Relief valves shall not be provided for thermal expansion where piping and equipment other than heat exchangers can be blocked in between valves except for liquid lines outside process areas (i.e. offsites).

Protection against over pressure will be provided when low boiling liquids can be blocked in and the pressure can be increased due to vaporization.

These criteria should be considered as general rather than specific in regard to both location and application. Certain situations will arise that may require deviation from these norms.

12.9.2 Heat sources may be any of the following:

a. Solar Radiation
b. Tracing
c. Process Heat

12.9.3 Thermal relief valve set pressure shall be the design pressure of the weakest component in the system being protected.

12.9.4 Thermal relief valves may discharge to an open drainage system, or to a safe location.

12.9.5 Thermal relief valves shall be 3/4" x 1" in size except for the following applications (for which valve sizes shall be calculated in accordance with API RP-521, Appendix A).

a. Long pipelines of large diameter.

b. Large vessels or exchangers operating liquid full.

12.9.6 If the liquid being relieved is expected to flash or form solids while passing through the relief device, the procedure in API RP-521, Paragraph 3.18 (A), shall be used.

12.9.7 Heat exchangers shall be protected by thermal relief valves set to initiate relief at 100 percent of design pressure when the cause of the pressure is one of the following:

a. Thermal expansion of liquid when the closure of a single valve isolates contents.

b. Light hydrocarbons service blocked inlet and outlet when the vapor pressure at 95°F exceeds the design pressure.

12.10 Depressuring Systems

12.10.1 Depressuring systems shall be designed in accordance with API RP-521.

12.10.2 Depressuring systems shall be used to relieve a high pressure (such as a hydrocracker reactor) during certain defined emergencies (such as temperature runaway). Requirement for depressuring systems in specific applications shall be reviewed by the Process Engineer.

12.10.3 Depressuring systems shall be remote manually activated.

12.11 Flare System Knock-out Drums

12.11.1 A knock-out drum shall be provided at the entrance to all flare stacks. Additional knockout drums shall be provided in the relief system if required for the following reasons:

a. To quench a hot relief stream so that the entire relief system need not be designed for high temperatures.

b. To collect liquid from a two-phase or liquid stream at any lateral.

c. To re-elevate the latter portion of the header system to allow continuous sloping.

PROCESS CRITERIA

12.11.2 Knockout drums shall be sized using the following formula*:

$$V_a = K \frac{(P_L - P_v)^{1/2}}{P_v}$$

V_a = Allowable vapor velocity ft/sec
P_L = Liquid density lb/ft^3
P_v = Vapor density lb/ft^3
K = 0.25 for vertical drums
K = 0.50 for horizontal drums (minimum L/D ratio of 2 required)

*K.O. drum sizing formula is based on the removal of a particle 400 micrometers (μ) in size.

12.11.3 Horizontal K.O. drums shall be assumed to be filled with liquid up to 1/4 of the diameter when applying the K.O. drum sizing formula. This point shall be the high liquid level.

12.11.4 Demister shall not be used.

12.11.5 Flare K.O. drums shall be located as close as possible to the flare stack to remove hydrocarbon liquids from the gas to be flared. Locate the drum in a location where the design maximum radiation intensity is less than 1200 Btu/hr ft^2 (excluding normal solar radiation).

12.11.6 K.O. drum liquid removal shall be accomplished by a drain valve or pump out, either of which shall be actuated automatically by high and low level switches.

12.11.7 15 minutes maximum calculated design liquid storage capacity shall be available in the K.O. drum up to 1/4 of the drum diameter.

12.12 Flare Pump Out System

12.12.1 The pump out pump should be rated for 50 percent of the maximum instantaneous liquid flow into the K.O. drum or 50 gpm minimum.

12.12.2 Rated pump head shall be based on the heaviest liquid gravity that is antiticpated.

12.12.3 Driver horsepower shall be based on the heaviest liquid gravity that is anticipated and shall be capable for taking the pump to end of curve.

12.12.4 Centrifugal pumps shall be rated for the highest viscosity liquid anticipated.

12.12.5 If there is the possibility of pump operation against a blocked discharge, a minimum flow bypass line shall be provided.

12.12.6 Available NPSH shall be determined in the same manner as a process pump (see Section 9.0, Pumps). K.O. drum liquid shall be assumed to be at its bubble point.

12.12.7 Electric motors shall normally be used as drivers. If substantial liquid loads will be introduced into the K.O. drums in the event of a power failure, Steam turbine driver or direct acting steam pump should be considered.

12.12.8 Pump out pumps will not normally be spared unless entry of liquids into the K.O. drum is expected to occur continuously or quite frequently or if alternate drivers are required.

12.13 Purging and Sealing

12.13.1 Molecular seals shall be specified for all flares. Water seals shall not be used.

12.13.2 Purge gas shall have a dew point below -20°F or the flare stack shall be winterized to maintain a temperature above the dew point of the gas.

12.13.3 Purge gas shall be introduced into the relief system at the end of each branch header. Purging rates shall be 0.2 to 0.3 ft/sec in the flare stack. The purge rate through each branch header shall be obtained by multiplying the total purge rate by the ratio of flow area of the branch to the total flow area of the flare stack.

12.13.4 Inert gas may be used for flare purging during startup.

12.14 Piping at Relief Valves

12.14.1 If pressure relief valves are fitted with block valves at both upstream and downstream sides or at the upstream side only, these block valves shall be car sealed and in an open position. Block valves shall be full ported and the same size as the adjacent relief valve inlet or outlet.

12.14.2 If spare pressure relief valves are provided, block valves shall be supplied at both the relief valves. These block valves shall be car sealed in an open position, except when removed for testing or repairs.

12.14.3 Relief valves discharging flammable fluids to the atmosphere unignited shall have snuffing steam connections on the relief valve discharge standpipe or discharge piping.

12.14.4 Relief valves should be located as close as possible to the equipment being protected to minimize the inlet piping pressure loss. Excessive pressure loss may be caused by fittings within inlet piping. As a general rule, such losses should be avoided.

12.15 Instrument Symbols and Identification

Refer to specification SP-1001-70-1 for Instrument Symbols and Identification.

PROCESS CRITERIA

13.0 PIPING

13.1 Line Sizing

13.1.1 General

a. Piping shall be designed in accordance with these design criteria and Specifications SP-1001-50-1 and SP-1001-50-3.

b. The fluid quantities to be used in determining line sizes shall be those called for by the maximum process design conditions. However, proper consideration shall be given to equipment capacity (pumps, etc.).

c. In sizing lines, consideration shall be given to economics, pressure drop, and to maximum permissible velocity from the standpoint of vibration, noise, and erosion.

13.1.2 Friction Losses and Velocities in Straight Pipe

a. The friction loss shall be calculated in accordance with the Standards of the Hydraulic Institute on the basis of clean commercial pipe. To these calculated pressure drops, a design overplus of 20 percent shall be added.

b. Liquids

1. Where liquids are being pumped, friction losses and velocities should generally be held within the following limits:

	Pump Suction (1) (2)		Pump Discharge (2)	
	Friction Loss, psi/100 ft	Velocity, ft/sec	Friction Loss, psi/100 ft	Velocity, ft/sec
Boiling Liquids (at equilibrium conditions)	0.05 - 0.25	1 - 4	1.0 - 4.0	5 - 15
Subcooled Liquids (oils at least 40°F (22°C) below the bubble point; water at least 10°F (6°C) below the bubble point.)	0.2 - 1.0	1 - 8	1.0 - 4.0	5 - 15
Cooling Water	0.2 - 1.0	1 - 8	0.5 - 2.0	5 - 15

PROCESS CRITERIA

1. (Continued)

NOTE (1): Pump suction lines are sized primarily by NPSH considerations; the above values are typical operating ranges.

NOTE (2): For reciprocating pumps, maximum instantaneous flow rates shall be used.

2. Where liquids are being moved by a pressure differential (including static head), and pressure drop is not a consideration, the maximum permissible velocity from the standpoint of vibration, noise, and erosion shall govern. In general, the velocity of liquids should be kept below 25 ft/sec.

c. Gases and Vapors

1. In general, friction losses should be held between 0.1 and 2.0 psi/100 ft of pipe for atmospheric or higher pressure systems and between 0.02 and 0.5 psi/100 ft for subatmospheric systems; or about 1 percent of the absolute pressure.

2. Where excess pressure is available, the above unit pressure drops may be increased, using 250 ft/sec as a limiting velocity in most cases.

d. Steam

1. The friction loss shall be calculated in accordance with the Standards of the Hydraulic Institute on the basis of clean commercial pipe. No design overplus shall be added.

2. High pressure steam (over 50 psig) lines shall in general be sized for a friction loss of 0.5 to 1.5 psi/100 ft of pipe, or about 1 percent of the absolute pressure. Short leads to pumps, turbines and other equipment in which the steam flow is steady shall be sized for a friction loss of 1.5 to 4.0 psi/100 ft of length.

The usual maximum velocities are 30 ft/sec per inch of pipe diameter from sizes from 3" to 6"

2. (Continued)

diameter; over 6" diameter, 200 ft/sec for saturated steam and 250 ft/sec superheated steam.

3. Low pressure steam (under 50 psig) lines shall in general be sized for a friction loss of 0.25 to 0.5 psi/100 ft length. When the steam is above atmospheric pressure, short leads from pumps, turbines, and other equipment in which the steam flow is steady shall be sized for a fraction low of 0.5 to 1.5 psi/100 ft of length or about 1 percent of the absolute pressure. Vacuum lines shall be sized on the basis of pressure drop available.

e. Liquid-Vapor Mixtures

1. The average density of the liquid shall be used in the calculation.

2. The average velocity of the mixture shall be greater than the calculated entrainment velocity, but less than the calculated erosion velocity. In general, friction losses shall be held to less than 4.0 psi/100 ft of pipe.

13.1.3 Limitations on Velocity

a. Vortexing Velocity

Liquid drawn out of the bottom of a vessel where liquid and vapor are in equilibrium or where a two phase liquid exists can entrap vapor or the lighter liquid by a vortex. In general, vortexing occurs when the static head above a liquid drawoff nozzle is less than two velocity heads. The simplest solution to a vortex is to install a vortex breaker in the drawoff nozzle and to limit the line to a maximum outlet velocity of 7 ft/second.

b. Feed to Columns

The feed to fractionating columns should not enter the vessel at a velocity great enough to sweep the liquid seal off the tray and destroy its efficiency. To this end feed distributors, tangential nozzles, flash zones, etc., are used as necessary.

c. Column Drawoff Nozzles

The suction box nozzles and line used to withdraw a stream from the side of a fractionating column should be sized according to the following table:

	Liquid Falling from Above	From Quiet Zone
Suction box max velocity	1 ft/sec	2 ft/sec

Drawoff nozzle max velocity	Liquid Falling from Above	From Quiet Zone
4 ft/sec	3 ft	2 ft
3	2-1/2	1-1/2
2	2	1
1	1	6"
Less than 1	6"	6"

This limitation is set to prevent trapped vapors from getting into the pump. From a point 10 ft below the drawoff nozzle the line can be reduced to that required for NPSH or other applicable criteria.

d. Condensate from Steam Traps

The condensate line from a steam reboiler to continuous drainer shall be sized for a maximum velocity of 1 ft/second. This limitation is set so that vapors will not get into the trap and affect its operation. Lines to and from bucket traps should be sized for the maximum capacity of the trap which is usually 2 or 3 times the average calculated flow.

13.1.4 Special Considerations

a. Column Overhead Lines

In most cases, column overhead lines shall be sized as follows:

System	Pressure Drop
Atmospheric and higher pressure	0.10 to 2.0 psi/100 ft
Below atmospheric pressure	0.02 to 0.5 psi/100 ft

PROCESS CRITERIA

a. (Continued)

In general, for atmospheric and higher pressure column, 1 percent of the operating absolute pressure shall be used as a maximum pressure drop per 100 ft of overhead piping. Overhead lines in vacuum service are generally sized on an economic basis.

b. Vacuum Heater Transfer Line

Vacuum heater transfer lines shall be sized in accordance with the procedure given in Edmister's "Applied Hydrocarbon Thermodynamics". These are usually large lines operating at or near acoustical velocities. They must be sized early to set the pressure at the vacuum heater outlet which affects the heater outlet tube pass arrangement.

c. Reciprocating Compressor Suction & Discharge Lines

Pulsation dampeners shall be provided on all reciprocating compressor suction and discharge lines. 1 percent of the operating pressure shall be allowed for pulsation dampener pressure drop. A reduction in this allowance should be considered for high pressure and multistage machines.

d. Simplex Pump Lines

Suction and discharge lines for simplex pumps shall be sized for 1.6 times the pumping rate.

e. Proportioning Pump Lines

Suction and discharge lines of proportioning pumps shall be sized for 3 times the pumping rate.

f. Start-up, shutdown, full, off-test and unit bypass lines may be required in operating units. Start-up and shutdown lines shall generally be sized for 1/2 normal flow. Fill lines shall be sized to fill system in a reasonable time, depending upon service. Likewise, with pressuring lines. An off-test header shall be sized for 1/2 of the flow of all products into the header. Unit bypass piping shall generally be sized for full flow. Lines in these services shall be sized to consume all of the pressure available.

PROCESS CRITERIA

13.2 Design Pressure and Temperature

13.2.1 General

a. The pressure and temperature design criteria for piping systems, shall conform to the following standards, codes and references:

1. American National Standards Institute Code for Pressure Piping, ANSI B31-3 - 1976, "Petroleum Refinery Piping" and the following Adenda:

   a) ANSI B31.3a - 1978
   b) ANSI B31.3b - 1978
   c) ANSI B31.3c - 1978
   d) ANSI B31.3d - 1980

2. Pressure-temperature ratings for flanged components 1/2 inch through 24 inch nominal operation (including fluid head). The most severe condition of coincident pressure and temperature under normal operation shall be that condition which results in the greatest required pipe thickness and the highest flange rating.

b. External pressure is defined as the maximum differential pressure (including fluid head) at the coincidental temperature, that can act externally on the component in the piping system, taking into consideration the failure of external or internal pressure.

c. The design pressure of a line shall be set by one of the following:

1. The set pressure of the relief valve on equipment when connected to the line plus the static head and friction loss.

2. The set pressure of the relief valve when mounted on the line.

3. The maximum pressure that a piece of equipment can generate such as, the shutoff head of centrifugal pumps, the stalling pressure of reciprocating pumps, etc.

c. (Continued)

Piping downstream of a control valve station shall have a line class selected for the downstream design conditions; except when a block valve is installed downstream, the downstream piping through the first block valve shall have a line class selected for the design conditions of the control valve station.

d. The design pressure of the line and equipment on the discharge side of a centrifugal pump shall be sized for the greater of the following two cases.

1. The normal suction pressure plus the shutoff differential head of the pump.

2. The maximum suction pressure plus the normal flow differential head of the pump.

e. Since piping is normally rated before pump curves are available, it is necessary to estimate the shut-off pressure. The following rules shall be used as a guide.

1. Straight centrifugal pump with medium and high heads, 25 percent shall be added to the normal specified differential pressure.

2. For very low head centrifugal pumps, 35 percent shall be added to the differential pressure.

3. For axial flow pumps, 80 percent shall be added or use a relief valve.

f. Compressor suction piping, including pulsation bottles, shall have the same pressure rating as the discharge piping up to and including the first suction block valve.

g. If positive displacement pumps are not equipped with a built-in pressure relieving device and if the stalling pressure of the pump is greater than the maximum pressure rating of the discharge piping and pump casing, a separate relief valve from discharge to suction shall be installed. The following table shall be used for relief valve setting which also sets the pressure rating of the piping.

g. (Continued)

The table gives multiplying factors to the normal pump discharge pressure.

	Without Dampener	With Dampener
Simplex	1.50	1.30
Duplex	1.40	1.25
Triplex	1.30	1.20

13.2.3 Design Temperature

a. Design temperature is defined as the metal temperature representing the most severe condition of coincident pressure and temperature.

b. The design temperature is normally set above the normal operating temperature because it is usually impossible to be able to calculate the exact flowing fluid temperature. Variations in compositions and operating pressures will influence the operating temperature in the system. Fouling of heat exchangers and furnaces has a great influence on the fluid temperatures. This equipment when new and clean will usually have a much higher transfer rate and consequently higher temperatures. However, if a heat exchanger or a piece of equipment in which heat is being applied can be removed or bypassed, then the line downstream of that equipment should be designed for the higher temperature.

c. As a general rule, the design temperature should be specified 20 to 30°F higher than the normal flowing fluid temperature when the normal temperature is greater than 25°F. For normal temperatures of 25°F or less, the design temperature should be specified 10°F lower than the normal flowing fluid temperature.

d. Many instances will arise where the design of the line with respect to wall thickness, etc., is not influenced too much by the temperature selected, and therefore designers have a tendency to arbitrarily apply a high design temperature. This practice should be avoided because these temperatures are used for other purposes such as thermal expansion of the pipe, hydrotest pressure, etc.

13.2.4 Variations

Variations in the temperature or pressure, or both, for normal operating conditions are characteristic of certain services. However, the lines that have short term variations should be noted on line sizing calculation sheets.

13.3 General Piping Details

13.3.1 Instruments

All gauge glasses and level instruments in all process services shall be provided with 1/2" minimum drain connection. Butanes and lighter, compounds shall be piped to the flare header. Gauge glasses in fouling service shall be piped for flushing.

13.3.2 Utility Piping

a. Steam and Steam Condensate Piping

1) Block valves for steam and condensate piping shall be provided as follows:

a) At the takeoff point of each major steam and steam condensate header lateral to a specific building or area.

b) At the header takeoff point of each steam and steam condensate lateral to and from individual equipment.

2) All steam laterals shall be taken off from the top of steam headers.

3) Steam lines shall be provided with condensate drip legs at low points and at the ends. Drip legs shall be line sized for lines 4 inches and smaller. For continuous headers 6 inches and larger, drip pots shall be sized for one line size smaller than the header. For non-continuous headers 6 inches and larger (i.e., end of header, change of direction, or pocketed line) use 1/2 header size (4 inches minimum).

PROCESS CRITERIA

3) (Continued)

In addition to the normal drain connection (to the steam trap) off the side of condensate drip pots, a valved drain connection (sized one and a half inch) should be provided off the bottom of the drip pot, to allow the periodic draining of stagnant condensate or accumulated solids.

4) Drip pots shall be provided on steam supply laterals to steam turbines only when the steam temperature is within 50°F of the saturation point.

5) Drip leg drains shall be provided immediately upstream of the steam inlets to turbines.

6) Steam traps discharging to the condensate header shall be isolated by means of valves, and equipped with a bypass valve to condensate header. Trap bypasses shall not be installed when trap discharge is into a closed condensate return system. Standby traps shall be considered on an individual basis. A flanged globe type bypass valve shall only be installed on steam traps with open discharge. Those valves will also be considered on an individual basis.

7) Process steam lines to equipment such as columns or to process lines should have a check valve at the inlet together with a double block bleed arrangement.

8) Steam traps discharging into the condensate system shall have isolating valves. Condensate shall be returned to the steam plant whenever practical.

9) All steam condensate which can be contaminated with hydrocarbons during normal operation or equipment failure, may not be connected to the steam condensate system and require special design consideration, such as analysis by a hydrocarbon detector.

10) In steam heated, exchanger or reboiler service, continuous drainers or pumps shall be used for condensate collection. In designing the condensate return system, it should be considered that steam pressure within the reboiler or exchanger will at times be throttled down to a pressure equivalent to a temperature nearly approaching the process fluid being heated.

11) Provide blowout connections at extremities of steam distribution headers, as close as possible to blank capped ends of headers. to allow flushing/clean-out prior to start-up. These blowout connections should consist of flanged drain connections sized two inches for headers eight inches and larger, and sized one and a half inches for headers smaller than eight inches.

b. Cooling Water

1) Cooling water lines entering the plot area should be provided with block valves at the plot limit.

2) Provisions shall be made to allow measuring water flow to each unit or group of integrated units.

3) Back flush piping shall be provided for all heat exchangers which are cooling by cooling water. Back flush piping shall be one line size smaller than the cooling water piping.

4) A circulating by-pass with valve shall be installed upstream of the supply and downstream of the return block valve for each unit or group of integrated units.

5) For cooling water systems provided with a cooling tower, block valves shall be installed at the inlet to each cell of the cooling water tower. The valves shall be accessible from ground level or operating platform.

PROCESS CRITERIA

c. Air Systems

Air systems shall include instrument air and plant air (total air) systems which shall be completely separated except for a tie-in to provide emergency instrument air, located upstream of driers.

1) The instrument air system shall be designed for a normal working pressure of 115 psig. A block valve shall be provided for each take-off connection from these headers. Instrument air lines shall also be provided with drains at the lowest points.

2) The plant air system is intended to supply for air-operated tools, cleaning, etc., and shall be designed for a working pressure of 125 psig. Hose connection at plant air lines shall be located where required for maintenance. These connections shall be one inch and of the quick-coupling type. The system shall be provided with drain connections at the lowest points.

3) Provide flanges on the ends of all instrument air distribution headers, to enable flushing/clean-out of system prior to consumption of air in instruments.

4) All laterals should be taken off the top of instrument air distribution headers.

d. Utility Stations

1) Pump and compressor area shall have manifolds provided with hose connections for steam, air and water. The manifolds should be located so that the whole area can be reached by hoses 50 feet long.

2) Steam, air and water supply manifolds should also be installed near columns, vessels, furnaces, heat exchangers, etc., where required for maintenance or cleaning purposes.

3) Steam connections shall be suitable for 50 psig and 300°F.

4) Nitrogen utility stations are to be provided in process areas where nitrogen is required for purging equipment at start-up and shut-down. A check-valve should be provided on all nitrogen utility stations.

13.3.3 Sample Connections

Attached is a typical engineering standard for sample connection details.

a. Unless otherwise specified by Tri-State, double valved sample connections (using a 3/4 inch line class main block valve, and a 1/2 inch bar stock needle valve for regulation) shall be provided as required to permit full evaluation, without disconnecting piping or instruments, during plant performance tests and on the steam outlet line from each steam generator. Liquid sample connections shall be taken off the side of the pipe. Vapor sample connections shall generally be taken off the top of the pipe. Sample connections shall be located so as to be accessible from ground level (preferably) or from principal platforms.

b. Sample points shall not be located in dead ends of piping.

c. Sample connections should be located in cooled product lines and grouped near the plot limit wherever possible. Where hot samples are necessary, sample connections above 200°F shall be provided with a permanently installed sample cooler.

d. If the vapor stream contains H_2S, the bleed connection shall be piped to a safe location.

13.3.4 Underground Piping

a. Firewater distribution systems, portions of cooling water systems, atmospheric drains and sewer systems, may be installed underground.

b. Underground piping shall be 3 inches minimum. Underground drains shall be 4 inches minimum.

PROCESS CRITERIA

13.4 Valves

13.4.1 General: (Refer to SP-1001-50-1 Section 5.10)

a. Every valve shall have the valve size identified on the mechanical flow sheet. All valves shall be line size unless the valve size is reduced for reasons listed in this criteria.

b. Control valves are considered operating valves. Any other valves which are operational shall be indicated on the MFD. Pump suction and discharge valves shall be considered as operating valves.

c. Operating valves requiring attention, observation or adjustment during normal operation, shall be located so as to be within reach from grade, platform or permanent ladder. Those valves will be identified on flow diagrams as "O.V." with the exception of control manifold bypass valves. Bypass valves around control valves shall also be accessible from grade, platform, or permanent ladder.

d. Except for the flare line, all piping entering and leaving the process area shall be provided with block valves and blinding provisions for unit isolation. The valves shall be located in a clear area and shall be accessible from grade or permanent platform.

e. Emergency plant shut-in valves and bypass valves around control valves (except battery limit header valves which shall be accessible from platform) shall be accessible from grade and shall be located in a clear area. The valves shall be tagged on the mechanical flow diagrams as ESD.

f. When the pressure differential across a manually operated valve used primarily for flow or pressure regulation exceeds 200 psi, and the valve is 2 inches or larger, the valve shall be a HIC type valve with handwheel.

g. Gear operators shall be used for valves in accordance with the following table:

13.4.1 g. (Continued)

Nominal Pipe Size

Rating	Globe Valve	Plug Valve
125#	-	12 inch and larger
150#	12 inch and larger	10 inch and larger
300#	8 inch and larger	10 inch and larger
600#	6 inch and larger	2 inch and larger
900#	4 inch and larger	2 inch and larger
1500#	3 inch and larger	2 inch and larger
2500#	3 inch and larger	2 inch and larger

h. All open ended valves shall be blanked.

i. Drain and sample lines connected to equipment or lines containing liquid butane and lighter hydrocarbons shall be provided with two valves in series. The two valves shall be at least 2 feet apart to provide for an emergency shutoff in case the line freezes during liquid flow.

j. Piping stress relief requirements for process reasons shall be indicated on the metallurgical flow diagram.

k. Pump suction and discharge valves should be considered as "operating valves" with regard to provision of good operating access.

13.4.2 Valve Selection

a. Gate Valves

1) Gate valves shall normally be used for manual isolation. Gate valves shall normally be hand wheel operated. Manual gear operators shall be specified on an individual basis.

2) Gate valves are the preferred type of block valve, unless other process conditions govern.

b. Plug Valves

1) Lubricated plug valves may be used in hot services up to a temperature of 500°F.

PROCESS CRITERIA

13.4.2 b. (Continued)

2) Nonlubricated mechanical lift-plug valves shall have gearing, as furnished by the valve manufacturer.

3) Plug valves are preferred in slurry or high solids content service.

4) Plug valves are preferred if a quick opening or tight shutoff valve is required.

5) Plug valve lubricant must be compatible with the process fluid.

6) Nonlubricated (teflon sleeve) plug valves may also be used.

c. Ball Valves

1) Allowable pressure/temperature ratings for ball valves shall be in accordance with MESC Code.

2) Ball valves may be used in slurry or high solids content service.

3) Ball valves may be used if a quick opening or tight shutoff valve is required.

4) Multiple port ball valves shall not be used.

d. Globe Valves

1) Globe valves are the preferred type of flow modulation valve, unless other process conditions govern.

2) Globe valves shall not be used if available system pressure drop is critical.

3) Globe valves are to be used in clean service; i.e., globe valves are unsatisfactory for use in high solid content service.

4) Manually operated valves used primarily for flow regulations shall be globe valves up to and including 12 inch and 14 inch size.

13.4.2 (Continued)

e. Angle Valves

1) Angle valves shall be used for high pressure drop services.

2) Angle valves shall be used instead of globe valves where a 90° change of direction in the piping is practical.

f. Y-Valves

1) Y-Valves are satisfactory for chemicals, nonabrasive high solids content or slurry service.

2) Y-Valves are preferred to gate or globe valves in above services.

3) Y-Valves shall not be used in abrasive service.

g. Needle Valves

1) Needle valves are preferred for sampling valves and control of flow in the low flow range.

2) Needle valves shall be used only in clean service.

h. Diaphragm Valves

1) Diaphragm valves are suitable as flow moduling valves for slurry service.

2) Diaphragm valves are suitable as flow modulating valves for toxic services.

3) Diaphragm valves shall not be used for control of flow in the low flow range.

4) The diaphragm material must be compatible with the process fluid; i.e., diaphragm valves are not suitable for high temperature or pressure.

5) Diaphragm valves are satisfactory for low available system pressure drop.

13.4.2 (Continued)

i. Drag Valves

1) Drag valves are preferred in high pressure letdown service, i.e., steam or hydrogen vent valves.

2) Drag valves must be used in clean service.

j. Butterfly Valves

1) Butterfly valves are preferred as flow modulating valves to control gas flows in low pressure systems.

2) High performance butterfly valves shall be used where tight shutoff is required.

3) Butterfly valves shall not be used if fine flow control is required.

4) Butterfly valves must be used in clean service.

5) Butterfly valves are preferred in cooling water systems for trim and shutoff valves.

k. Swing Check Valves

1) Swing checks shall be mounted only in the horizontal or upward position.

2) Swing checks are the preferred type of single direction flow valve unless process conditions otherwise govern. Use wafer type for 6" and larger services.

3) Swing checks are suitable for clean liquid or vapor service.

4) Swing checks shall not be used if tight shutoff is required.

l. Lift Check Valves

1) Lift checks shall be mounted only in the horizontal or upward position.

13.4.2 l. (Continued)

2) Lift checks shall not be used if tight shutoff is required.

3) Lift checks must be used in clean service.

m. Ball Check Valves

1) Ball check valves may be mounted either horizontally or vertically.

2) Ball check valves are satisfactory in viscous service.

3) Ball check valves are preferred for cyclical operation.

4) Ball check valves shall not be used if a tight shutoff is required.

5) Ball check valves must be used in clean service.

6) Ball check valves shall not be used if available system pressure drop is critical.

n. Foot Valves

Foot valves shall be used in nonsubmersible sump pump suction lines. Sump pump NPSH available shall include resistance for the foot valve.

o. Restrained Check Valves

1) Restrained checks are preferred in systems that cannot tolerate surge pressures.

2) Valve body selection shall be based on same criteria as nonrestrained check valves.

p. Steel valves shall be installed against water storage tank nozzles and at the battery limits in utility water supply and return lines. Such valves shall be identified on flow diagrams and drawings.

PROCESS CRITERIA

13.5 Fittings

The following charts present values for pressure drop determinations of various pipe fittings. The data sheets are an incorporation of information from the Crane Company Technical Paper No. 410 (1957) and Standards of the Hydraulics Institute (1954). The pressure drop values which are shown on the charts do not coincide exactly with either publication. However, these values are considered to be the most representative that can be obtained from existing knowledge. An effort has been made to maintain pressure drop consistency between fittings.