CHAPTER TEN

Refinery Off-Site Facilities and Utility Systems

REFINERY TANKAGE

Tanks are required in refineries for storage of crude, blend stocks, and products for shipping. Tanks are also required as charge tanks for many secondary processing units. In a refinery, the cost of tanks alone roughly equals that of all the process units in it.

From an operational point of view, refinery tankage can be divided into the following categories: crude storage tanks, charge tanks for secondary processing units, base stock or component storage tanks for product blending, and shipping tanks. Tanks used in various utility services are not considered here.

CRUDE STORAGE

From the viewpoint of operational safety, a refinery located close to an oilfield or pipeline terminal requires a minimum inventory equivalent to 16 hr throughput. This includes a 4-hr allowance for settling, sampling, and testing. The total minimum operating inventory comprises the following elements: crude oil working stock (= 16 hr crude throughput), unavailable tank heels (of all crude tanks in operation), and line content. In practice, a storage capacity equivalent to 48 hr crude throughput is generally considered adequate for such refineries.

For coastal refineries, which are supplied crude by marine tankers, the crude storage capacity is dictated by the parcel size and frequency of crude tankers. Normally, storage capacity equivalent to 15 days throughput is considered adequate.

CHARGE TANKS

Charge tanks are required for most secondary processing units. Charge tanks are required as surge tanks, to insulate the unit from any temporary upset upstream of the unit from which it is receiving feed. These are essentially low-capacity tanks with a working capacity of approximately 3–4 days operation of the unit it is feeding. For example, if a refinery has a naphtha unifiner, cat reformer, diesel hydrodesulfurizer, and hydrocracker, each unit may have a charge tank. Any upset in the crude unit is prevented from affecting operation of these units. Crude storage tanks can be considered charge tanks for crude distillation units.

BASE STOCK TANKS

Product received from any single unit of the refinery may not necessarily be a finished product. It can be feedstock for another processing unit or a blend stock for a product or group of products. For example, reformate from the cat reformer unit may be a base or blend stock for all the gasoline grades being produced by the refinery. If a tank is utilized to store an intermediate stock from a refinery unit for product blending, it is called a *base stock tank.* In refineries with a continuous on-line blending system, base stock tanks also serve as shipping tanks.

SHIPPING TANKS

Various base stocks are blended to yield finished products. Finished products, after blending and testing in the refinery laboratory, are stored in shipping tanks. The shipping tanks constitute the major part of tankage in a refinery, if batch blending methods are employed. The working storage capacity required for any product group is determined from the following factors: production rate, maximum parcel size, number of different product grades in a product group, and product loading rates.

The production rate, in tons or barrels per day, for all product groups (naphtha, gasoline, kerosene, diesel, and fuel oil) can be determined from the overall material balance of the refinery.

The maximum parcel size is the quantity, in tons or barrels, lifted from the terminal by a single ship at a time. It depends on the dwt (dead weight tons) of the tanker arriving to lift products and storage capacity available for that product in the refinery. All refinery terminals have norms for the maximum allowable loading time for different-sized tankers, within which loading must be completed.

SHIPPING TERMINALS AND SEA LINES

Blended products are stored in shipping tanks away from the process area. From shipping tanks, the products are pumped by high-capacity shipping pumps through dedicated sea lines to loading arms at the piers and finally by hoses to individual tankers. The terminal product transfer lines sizes and pumping capacities are designed to achieve the required loading rates for different product groups. For example, if the maximum parcel size of naphtha is 80,000 tons, the loading pumps be able to pump the product from a number of shipping tanks to the ship within a reasonable time. A 30-hr loading time may be allowed for a 80,000 dwt tanker, requiring a loading rate of 2700 tons per hour. Also, the sea lines must be suitably sized to take this product rate within the permissible pressure drop. The sea line required for this service may be 16–20 in. in diameter. Marine terminals usually have a number of berths. Each berth, in turn, has restrictions as to the minimum and maximum dwt of the tanker it can accept. Specifications of a typical marine terminal serving a 250 mbpd refinery are shown in Table 10-1. Each of the berths may not have connection to all sea lines. Normally, each product group has at least one dedicated sea line.

Facilities available at the marine terminal (maximum size of the tanker accepted, tanker loading rates, etc.) decide the maximum parcel size and capacity of shipping tanks required for a given production rate of the refinery.

The working capacity of base stock and shipping tanks is computed taking into account the following components:

- 10 days product storage.
- Contingency equivalent to 10 days production of the refinery.
- One maximum size parcel for each product group.
- Any fixed requirement for each product group.

Contingency storage capacity is required for unforeseen situations, such as slippage of vessels causing lifting delays, disruption of export schedule due to bad weather conditions, or scheduled and unscheduled shutdowns of key refinery units. Working capacity also takes into account

Table 10-1
Specifications of a Typical Refinery Marine Terminal

	SHIPPING LINE					
PRODUCT	**1**	**2**	**3**	**4**	**5**	**6**
NAPHTHA	X					
MOGAS		X				
ATK/KEROSENE			X			
DIESEL				X	X	
FUEL OIL						X
MAXIMUM PUMPING RATE 000' tons/hr	2.22	2.22	2.22	2.22	2.22	2.22

	dwt RESTRICTIONS		
BERTH	**MIN.**	**MAX.**	**SHIPPING LINE CONNECTIONS**
1	10	160	1, 3, 4, 5, 6
2	10	50	1, 3, 4, 5, 6
3	10	160	1, 2, 3, 4, 5, 6
4	10	50	1, 2, 3, 4, 5, 6
5	10	50	1, 2, 3, 4, 5, 6

loss of storage capacity due to release of tanks for scheduled and unscheduled maintenance.

REFINERY TANKAGE ESTIMATION

For estimating the tankage requirements for a refinery, the following information is required:

1. Refinery process unit capacities, in tons and barrels per day.
2. Refinery material balance and product blending schedule. (Figure 10-1).
3. Rundown temperature of all streams flowing to the base stock and shipping tanks (Table 10-2) to determine product density.
4. Information on the refinery marine terminal product loading facilities; that is, the available sea lines, product pumping rates, and connections to various berths (Table 10-1). A refinery maintains

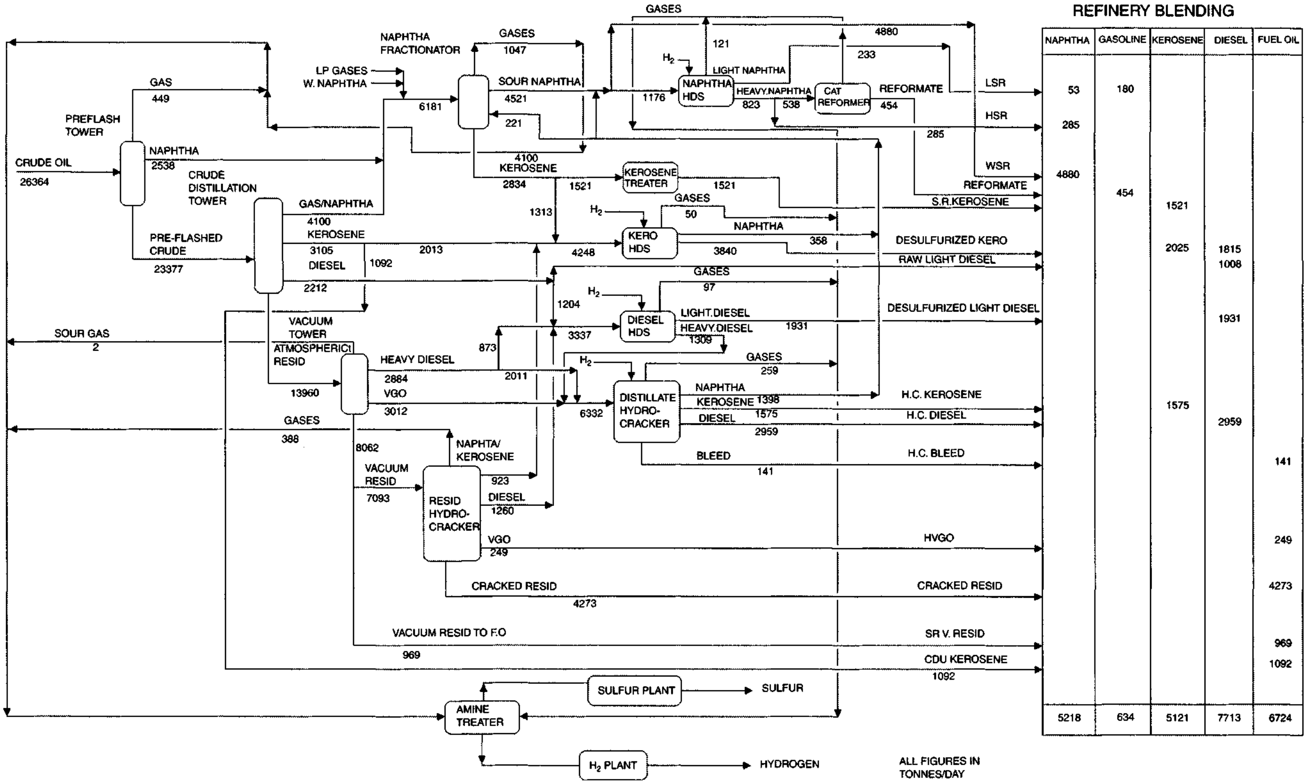


Figure 10-1. Refinery block flow diagram and blending schedule. SR = straight run; LSR = light straight run; HSR heavy straight run; WSR = whole straight run; VGO = vacuum gas oil; HVGO = heavy vacuum gas oil; CDU = crude distillation unit; H.C. = hydrocracker; SR.V.Resid = Straight Run Vacuum Resid.

Table 10-2
Storage Temperatures of Refinery Streams

STOCK	TYPE	NORMAL FLASH POINT, °F	MINIMUM FLASH POINT, °F	NORMAL RVP, psi	MAXIMUM RVP, psi	NORMAL STORAGE TEMPERATURE, °F
CRUDE OIL	FLOATING			6.0		115
FULL RANGE NAPHTHA				7–9.5		105
CAT REFORMER CHARGE	FLOATING			1.5		100
REFORMATE	FLOATING			8–9	9.5	100
UNLEADED GASOLINE	FLOATING			8–10	10.5	100
KEROSENE UNIFINER CHARGE	FLOATING					125
KEROSENE/DIESEL	FIXED	100–160	100/140			110
DIESEL	FIXED	150–200	140			125
MARINE DIESEL OIL	FIXED	150–180	130			110
DIESEL HDS CHARGE	FLOATING	>200	200			160
RAW LIGHT DIESEL	FLOATING	150–230	150			140
DESULFURIZED GAS OIL	FIXED	>200	150			125
HYDROCRACKER CHARGE/HVGO	FLOATING	>200	200			175
FUEL OIL	FIXED	150–230	150			155
RESID HYDROCRACKER CHARGE/V.R	FIXED	>200	200			490
SLOP	FIXED			0–15		110

HVGO = HEAVY VACUUM GAS OIL; VR = VACUUM RESID.

historic data of previous years on the average and maximum size of tankers calling on the terminal to take product, by product group (naphtha, kerosene, diesel, fuel oil. etc.), which serves as the basis for future projections (Table 10-3).

An example for determination of the working capacity of refinery tankage follows.

EXAMPLE 10-1

A coastal refinery processes 180,000 barrels per day of 30.6 API Middle Eastern crude. The capacity of various processing units in mbpd and tonnes/day are shown in Table 10-4. Figure 10-1 shows the overall material balance and product blending schedule of the refinery. Table 10-2 shows the rundown temperatures of base stocks and blended products. Table 10-5 shows the facilities available at the refinery marine terminal. Table 10-1 shows the historic for the distribution of tanker fleet arriving at the terminal for product removal.

The refinery employs a batch blending system. The crude is received into the refinery tankage from the pipeline from oil fields. We want to estimate the tankage requirement for storing crude oil, charge tank capacities, and shipping tankage capacities for the product slate of this refinery.

SOLUTION

Crude Oil and Charge Tanks Capacities

Estimated crude oil storage requirements are based on 48-hr crude storage. Various processing units charge tanks are based on 3–4 days of feed storage, depending on the process requirements of the unit (Table 10-6).

Base Stocks and Shipping Tanks

Table 10-5 shows the calculations for estimating the shipping tankage required for every product group. Base stock tankage capacity is also considered a part of shipping tankage capacity in a given product group. As discussed earlier, operational capacity is based on 20 days production (10 days production and 10 days contingency) plus one maximum parcel

Table 10-3
Distribution of Tanker Fleet

TANKER DWT RANGE, 1000 TONS			PERCENT OF CARGO VOLUME				
MINIMUM	MAXIMUM	AVERAGE	NAPHTHA	KEROSENE	MOGAS	DIESEL	FUEL OIL
10	20	15	0	0	0	1	0
20	30	25	2	10	10	10	4
30	40	35	31	47	46	42	4
40	60	50	10	28	18	24	6
80	100	90	37	0	0	4	33
100	130	115	11	3	0	3	28
130	160	145	0	0	0	1	12
160	190	175	0	6	0	4	2
190	220	205	0	1	0	0	0
AVERAGE PARCEL SIZE, 1000 TONS			53	44	38	45	86

Table 10-4
Refinery Unit Capacities

UNIT	000' bpsd	000' TONS/DAY
CRUDE DISTILLATION	180.00	24.98
VACUUM DISTILLATION	85.00	13.23
NAPHTHA UNIFINER	36.00	4.16
CATALYTIC REFORMER	15.00	1.92
KEROSENE UNIFINER	31.50	4.02
DIESEL UNIFINER	22.50	3.16
KEROSENE MEROX	15.00	1.90
DISTILLATE HYDROCRACKER	41.30	6.00
RESID HYDROCRACKER	41.20	6.72

BPSD = BARRELS PER STREAM DAY.

size. To the capacity so estimated is added any fixed product requirements for a product group; for example, tankage required for local marketing, bunker sales, or meeting seasonal requirements for a particular grade.

PRODUCT BLENDING SYSTEM

The process units produce various product components and base stocks, which must be combined or blended, sometimes with suitable additives, to manufacture finished products. These finished products are generally grouped into the broad categories of gasoline, kerosene, diesel and fuel oil, and so forth.

Different methods of product blending are used to suit variation in the type of product, available components, operating procedures, shipping and marketing requirements, and available storage facilities. Blending methods normally employed include batch blending, partial in-line blending, and continuous in-line blending.

Petroleum products are shipped in bulk using pipelines, marine tankers, and occasionally road or rail facilities.

BATCH BLENDING

In batch blending, the components of a product are added together in a tank, one by one or in partial combination (see Figure 10-2). The materials are then mixed until a homogenous product is obtained.

Table 10-5
Estimation of Product Tankage Requirements

PRODUCT	PRODUCT TYPE	PRODUCTION RATE[2] TONS/DAY	OPERATIONAL REQUIREMENTS[1] 000' TONS	PARCEL SIZE[3] 000' TONS	FIXED[4] REQUIREMENTS 000' TONS	TOTAL CAPACITY	
						000' TONS	000' BARRELS
NAPHTHA	LSR	848.0	17.0				
NAPHTHA	WSR	1998.6	40.0				
NAPHTHA	GROUP TOTAL	2846.6	56.9	80	11.0	147.9	1321
REFORMATE	98 RON	0.0	–				
REFORMATE	96 RON	69.6	1.4				
MOGAS 90	90 RON	289.5	5.8				
MOGAS 98	98 RON	1179.6					
MOGAS	GROUP TOTAL	1538.7	30.8	35	12.0	77.8	676
KEROSENE	DPK	1005.5	20.1				
KEROSENE	JP-5	805.2	16.1				
KEROSENE	GROUP TOTAL	1810.7	36.2	80	108.0	224.2	1771
DIESEL	0.2% S	6494.1	129.9				
	53 CETANE	2494.1					
DIESEL	GROUP TOTAL	8988.2	179.8	80	0.0	259.8	1933
MARINE DIESEL		615.9	12.3				
MARINE DIESEL	GROUP TOTAL	615.9	12.3	80	70.0	162.3	1152
FUEL OIL	3.5% S, 380 CST	3995.7	79.9				
1% SULFUR FUEL OIL	3.5% S, CRACKED	2585.7	51.7				
FUEL OIL	GROUP TOTAL	6581.4	131.6	100	80.0	311.6	2029
TOTAL PRODUCTION		22381.5	447.6			1183.6	8882

NOTES:

[1] OPERATIONAL REQUIREMENTS EQUIVALENT TO 20 DAYS PRODUCTION.

[2] CORRESPONDING TO REFINERY CRUDE THROUGHPUT OF 180 MBPSD.

[3] MAXIMUM PARCEL SIZE DEPENDENT ON TANKER SIZE FOR PRODUCT LIFTING, CAPACITIES OF SHIPPING TANKS, AND LOADING RATES OF THE TERMINAL.

[4] FIXED REQUIREMENTS CORRESPOND TO STORAGE CAPACITY REQUIRED FOR SPECIFIC PRODUCT GRADES TO MEET SEASONAL REQUIREMENTS, LOCAL MARKETING, OR OTHER SPECIFIC USES.

Table 10-6
Crude Storage and Units' Charge Tank Capacities

UNITS	STORAGE TIME hr	WORKING CAPACITY 000' TONS	000' BBLS
CRUDE STORAGE	26	27.05	195
NAPHTHA UNIFINER	72	12.47	108
CATALYTIC REFORMER	96	7.67	60
KEROSENE UNIFINER	72	12.07	94.5
DIESEL UNIFINER	72	9.48	67.5
DISTILLATE HYDROCRACKER	72	17.99	123.9
RESID HYDROCRACKER	96	26.88	164.8

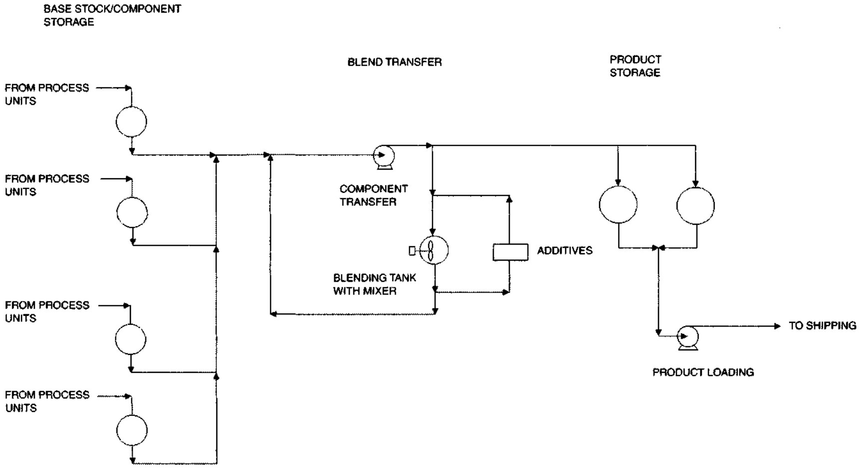


Figure 10-2. Batch blending system.

The components are run from process units to "base stocks" tanks. Each component stream is next pumped separately from base stock tanks into a blending tank, and the tank is gauged after each addition. Additives such as gasoline dyes, TEL (tetraethyl lead, a gasoline additive for increasing octane number of gasoline) kerosene antistatic or antiicing agents, diesel flow improvers, and the like are then added and mixed thoroughly. After laboratory analysis, the blended product is pumped to storage or shipping tanks.

When butane is blended into gasoline, the batch procedure is varied to bring butane into the tank after line-blending it with another component. In this manner, the butane blended is dissolved in the heavier material with less butane waste and without the fire hazards introduced by static electricity generated by in-tank blending of butane.

Storage tanks are required for base stocks and finished product shipping. The required capacity can be estimated depending on the refinery production rate and shipping parcel size. The capacity of mixing or blending tanks is not included in the total storage capacity. These tanks are usually of sufficient capacity to allow blending two to three days product per batch.

Components are transferred to the mixing tank by one or more pumps. A pump of relatively high capacity is required because each component must be transferred and gauged separately. In general, each component transfer pump is large enough to fill the blending tank in approximately 3 hr.

The blended material must be mixed thoroughly by propeller mixers, in-tank jet mixers, or recirculation pumps and piping. For large tanks, multiple mixers are required. For blending by in-tank jet mixers, a pump is necessary. The pump takes suction from the blend tank and discharges it, through suitable piping, back to the tank.

If the discharge into the tank is through a distribution spider or a swing line, a large-capacity pump is necessary. The mixing is considered complete when the entire contents of the tank has been pumped through the pump at least once.

A jet mixer consists of a nozzle instead of a spider or swing line. This nozzle is directed upward from the bottom of the tank at an angle. The high velocity of the jet stream induces circulation of the entire contents of the tank. The pump used with the in-tank jet mixer can be a low-capacity, high-head pump. After the required mixing hours, samples of the blended product are drawn from the top, middle, and bottom of the blending tank, and the three samples analyzed in the laboratory. If the three analyses are identical, the blending is considered satisfactory and the blended material can be transferred to the shipping tank. If the three analysis results are not identical, more mixing time is allowed until the tank contents are uniformly mixed.

Batch blending is most adaptable to use in small refineries, in which a limited variety of blends are to be produced. In a refinery, the cost of extra blending tanks, pumps, and related equipment may not be as large as the cost of instrumentation and equipment needed for in-line blending; and for this reason, many large refineries continue to use the batch blending system because of its ease and flexibility of its operation.

PARTIAL IN-LINE BLENDING

Partial in-line blending is accomplished by adding together product components simultaneously in a pipeline at approximately the desired ratio without necessarily obtaining a finished specification product (see Figure 10-3). Final adjustments and additions are required, based on laboratory tests, to obtain the specification product. In partial in-line blending, the mixing is required only for final adjustment. Additives, if any, such as dye for gasoline, are added as a batch into the blending header during the final stages of the blend or final adjustment stage.

The required components are pumped simultaneously from each base stock tank through the appropriate flow controller into a blending header. The component is mixed by turbulence in the header, as combined components flow to the finished product storage tank. Additives are introduced into the blend by a bypass stream with a suitable booster pump to an aductor or by a proportioning pump delivering a premix.

For partial in-line blending, an individual pump is required for each component. The capacity of the pump must be established to permit simultaneous pumping and delivery of one day's blend to product tanks within a reasonable time. The usual practice is to complete a blending operation within about 6 hours. The quantity of each component of a blend must be proportioned by the use of a flow meter and control valve.

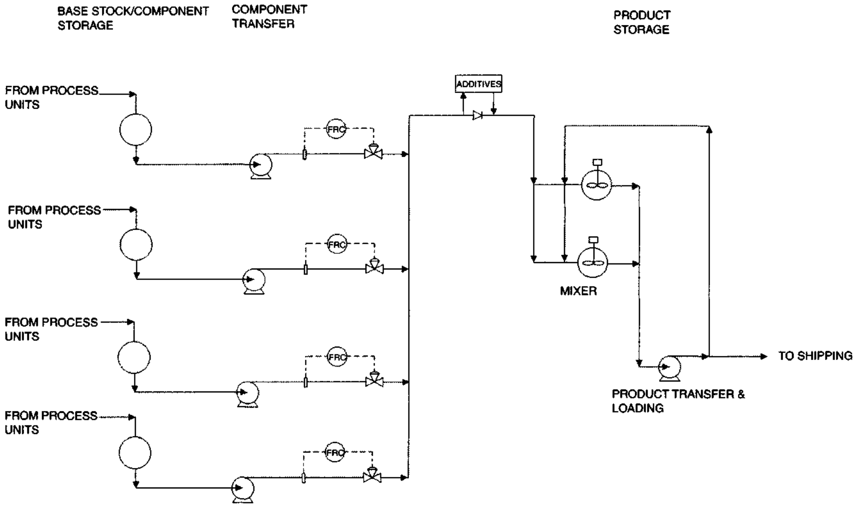


Figure 10-3. Partial in-line blending system. FRC = flow recorder and controller.

Flow controllers are set to a predetermined rate and flow is recorded. Flow meters used for partial in-line blending need not be extremely accurate. Accuracy ranges of 5% as attained with orifice meter are suitable. Mixers are required in final storage tanks for correction of blends by addition of components.

Partial in-line blending is suitable for moderate-sized refineries, where the cost of blend tanks would be excessive and blending time must be minimized. Blending time is substantially reduced because of the following:

1. Simultaneous pumping of components instead of consecutive pumping, as is the case in batch blending.
2. Reduction of overall mixing time.
3. Elimination of multiple gauging operations.

Many refineries prefer partial in-line blending as an initial installation that can be adapted to continuous blending in the future with minimal change in pumps, piping, and tankage. The disadvantages are the cost of additional meters, flow controllers, and pumps and high maintenance costs of the instruments.

CONTINUOUS IN-LINE BLENDING

In continuous in-line blending, all components of a product and all additives are blended in a pipeline simultaneously, with such accuracy that, at any given moment, the finished specification product may be obtained directly from the line (see Figure 10-4). As a result of the accuracy and safeguards included in the system, no provision is necessary for reblending or correction of blends.

Each base stock component is stored in two tanks. Samples of the component are test blended in the plant laboratory, and blends are analyzed to determine the most suitable proportion of components and additives for a specified product. The required components and additives are then pumped simultaneously, at a controlled rate, into a blending header. Various methods of controlling individual flow rates with interlock provisions have been used to ensure delivery of only the specified material.

The product can be sent to final storage, delivered to the product pipeline for transmission to a remote terminal, or loaded directly onto marine tankers.

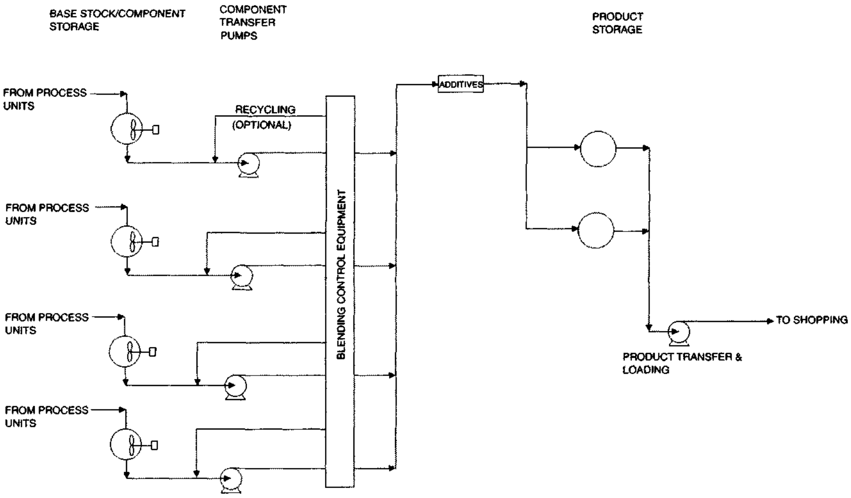


Figure 10-4. Continuous in-line blending system.

Storage tanks are required for components and most additives. Storage of the blended product is required only to suit shipping methods. Thus, the greatest proportion of storage can be in the form of components or base stocks, with minimum finished product storage.

An individual pump is required for each component. Pumps are also required for dyes and additives preparation and delivery. Dyes and additives are stored in solution form and added by proportioning pumps.

The quantity of each component of a blend must be accurately delivered. The recording flow meters and flow control valves used to proportion components are similar to those used for partial in-line blending, but a greater degree of accuracy is necessary. An accuracy of 0.25% or better is expected. Orifice meters are unsuitable for use in continuous in-line blenders. Positive displacement meters, venturi tubes, or velocity meters are generally used.

To ensure continued accuracy of the blends under varying operating conditions, the blending equipment is designed to provide for adjustment of individual component flow in proportion to total flow. Failure of the system to readjust should result in complete shutdown of the blending operations by means of flow stoppage or recycle.

Two types of blending controls are used to adjust component flows to desired rates: a mechanical system or an electronic system. In the mechanical system, the rotary motion generated by component flow in the meter is matched through a differential gear device against preset rotary motion. When the metered rate differs from the preset rate, pneumatic or electronic controls are actuated to adjust the flow control valve and change the flow rate to the desired value.

In the electronic system, electronic pulses are generated as a result of fluid flow through the meter. These are matched against preset pulses generated by an electronic device. Differences in pulse rate are detected by a digital totalizer, which feeds back a signal to adjust the flow control valve and adjust the flow to desired value.

To ensure the accuracy of the blend, it is necessary to calibrate meters frequently. One method of meter calibration is to remove the meter from the system and replace it with a calibrated space meter. This requires use of a prover tank or similar device, which can also be used to calibrate product shipping meters.

As a result of work involved in replacing a large numbers of meters frequently, many refineries that use continuous in-line blending system use a metering loop in the blending system. Such a loop is basically a pipe of known length and, therefore, known volume. The flowing fluid forces a "pig" through the loop, passing control points from which signal are sent for comparison. Loops are generally made of 600–1000 feet of 8-in, diameter pipe to ensure sufficient accuracy with electronic controls and digital totalizers.

Continuous in-line blending is best for large refineries that make several grades of products. When products can be transported directly to a pipeline or bulk transport, such as tankers, continuous in-line blending is economically more attractive than the batch methods because of the following factors:

1. Reduced blending time.
2. Minimum finished product storage, since components are stored and blended as required.
3. Increased blending accuracy with minimum "give away" on quality.
4. Reduction in loss through weathering of the finished product.
5. Minimum operating personnel.

However, the following disadvantages are associated with a continuous in-line blending system:

1. When products are transferred directly to a pipeline or bulk transport, a complete blender is required for each product, which must be

loaded simultaneously. For example, if a tanker is to be loaded with two grades of gasoline simultaneously, two blenders are necessary; otherwise, the advantage of reduced product tankage cannot be realized.

2. There is extreme difficulty in correcting errors, if they occur. As a result of safeguards built into the system, the only possible errors are human errors.
3. High initial investment and high maintenance cost of instruments.

REFINERY FLARE SYSTEM

Flaring is used as an effective and safe method of hydrocarbon vapor disposal whenever excess hydrocarbons must be controlled due to equipment failure or major emergencies, such as instrument malfunction, power failure, or plant fire. Before the utilization of flares, the gaseous waste streams were vented directly to atmosphere. This created two problems. The first is personnel and neighborhood safety. There was always the possibility of combustible vapor reaching the ground in sufficient concentration to be ignited. The result would be an explosion and fire, with devastating consequences for the operating personnel. The second problem was that the hydrocarbon discharges produced a major strain on the environment, and their emissions had to be controlled. Flaring provided a good solution to these problems but not without its own problems of heat, smoke, light, and noise. By burning the hydrocarbon vapor, the pollutants are converted to safe, less-noxious components: carbon dioxide and water vapor. The combustion process, however, generates a lot of heat, and thermal radiation from the flame must be reduced to levels safe for nearby operating personnel and equipment.

FLARE SYSTEM DESIGN

The flare system is designed to provide safe receipt and disposal of combustible, toxic gases and vapors released from process equipment during normal operation and during upset conditions. The safe disposal is achieved by knocking down the heavy ends and condensables in the flare knockout drum and burning the gases through an elevated stack. A controlled amount of steam is used to ensure smokeless burning and easy dispersion of combustion products. The process helps maintain an acceptable level of pollution at ground level.

A flare facility, particularly the flare burner, must have a stable flame capable of burning the hydrocarbon vapor released during a major operational failure. Also, the vapor must be sufficiently free from liquid droplets before entering the stack. Smoke is minimized by the injection of steam into the flame. The stack is located remote enough from operating units to provide safety for operating personnel and equipment. The flare system is purged with inert gas to prevent flame flashback.

BURNER DIAMETER

A flare stack, particularly the flare burner, must be of a diameter suitable to maintain a stable flame and prevent a blowout should there be a major failure. Flame blowout occurs when vapor exit velocities are as high as 20–30% of sonic velocity of the stack vapor.

The diameter of the flare burner can be determined from the following relationship:

$$d^2 = \frac{W}{1370}\sqrt{\frac{T}{M}}$$

where

D = diameter of the flare tip, in.;

W = mass flow, lb/hr;

T = temperature of vapor, °Rankine;

M = molecular weight of vapor.

This equation is based on specific heat ratio of $K = 1.2$, which is generally true for most hydrocarbon vapors. For vapors of significantly different values of K, the stack diameter obtained above is multiplied by $1.25\,K^{-0.25}$.

KNOCKOUT DRUM

A knockout drum in a flare system is used to prevent the hazards associated with burning liquid droplets escaping from flare stack. Therefore, the drum must be of sufficient diameter to effect the desired liquid/vapor separation. The drum diameter can be obtained from the following empirical relation (for a horizontal knockout drum to separate drops of up to 400 micron particle size):

$$D^2 = \frac{W}{9900}\sqrt{\frac{T}{M}}$$

where

D = diameter of the drum, ft;
W = mass flow rate, lb/hr;
T = temperature of vapor, °Rankine;
M = molecular weight of the vapor.

This equation is applicable to a single-flow knockout drum. Split-flow drums, where vapor enters in the middle of the drum and leaves it at both ends, have twice the capacity of single-flow drums. The diameter of split-flow drums is, therefore, 0.7 times the diameter obtained from this equation. The equation is based on an empty drum. An increase of diameter may be required if the drum is to hold a large volume of liquid. Vertical drums usually require a larger diameter, about 1.4 times the diameter for single flow drums. The length/diameter ratio for a horizontal drum is between 3 and 4. Also, the diameter of the knockout drum is three to four times the stack diameter.

HEIGHT AND LOCATION OF THE FLARE STACK

In designing a flare, the effect of heat radiation on operating personnel and equipment is considered. The selection of height and location of flare is done on the basis of safety for operating personnel and equipment. The effect of heat radiation on human beings is as follows:

HEAT INTENSITY, Btu/(hr)(ft^2)	PAIN THRESHHOLD	BLISTERING
2000	8 sec	20 sec
5300	—	5 sec

With a heat intensity of 2000 Btu/(hr)(ft^2), which is six times the solar radiation, the pain threshhold is 8 sec. Therefore, if time is to be allowed for a person to run to safety, the individual should not be subjected to a heat intensity of higher than about 1500 Btu/(hr)(ft^2) in the event of a major refinery failure (Figure 10-5(c)). A stack of sufficient height can be selected to satisfy this condition. Radiation levels used for design are

Service	**Btu/hr(ft^2)**
Equipment protection	3000
Personnel, short-time exposure	1500
Personnel, continuous exposure	440

Solar radiation adds to the calculated flame radiation. Typical values are 200–300 Btu/hr(ft^2).

Thermal radiation is of prime concern in flare design. Thermal radiation must be calculated to avoid dangerous exposure to personnel, equipment, and the surrounding area (trees, grass, etc.). The following calculation procedure is a convenient way to find the height of the flare stack and intensity of radiation at different locations.

The heat intensity is given by the following relation:[1]

$$I = \frac{\text{flow} \times \text{NHV} \times \varepsilon}{4\pi R^2}$$

where

I = radiation intensity at point X, Btu/hr (ft^2);

flow = gas flow rate, lb/hr;

NHV = net heating value of flare gas, Btu/lb;

ε = emissivity;

R = distance from flame center to point X.

This equation has been found quite accurate for distances as close to the flame as one flame length. The preceding equation is perfectly valid so long as proper values of emissivity are inserted. Emissivity is considered a fuel property alone. Emissivity of some common gases follow:

GAS	EMISSIVITY
CARBON MONOXIDE	0.075
HYDROGEN	0.075
METHANE	0.10
HYDROGEN SULFIDE	0.070
PROPANE	0.11
BUTANE	0.12
ETHYLENE	0.12
PROPYLENE	0.13

To calculate the intensity of radiation at different locations, it is necessary to determine the length of flame and its angle with respect to stack. A convenient expression to estimate the length of the flame is as follows:[2]

$$L_f = 10 \times D \times \left(\frac{\Delta P}{55}\right)^{0.5}$$

where

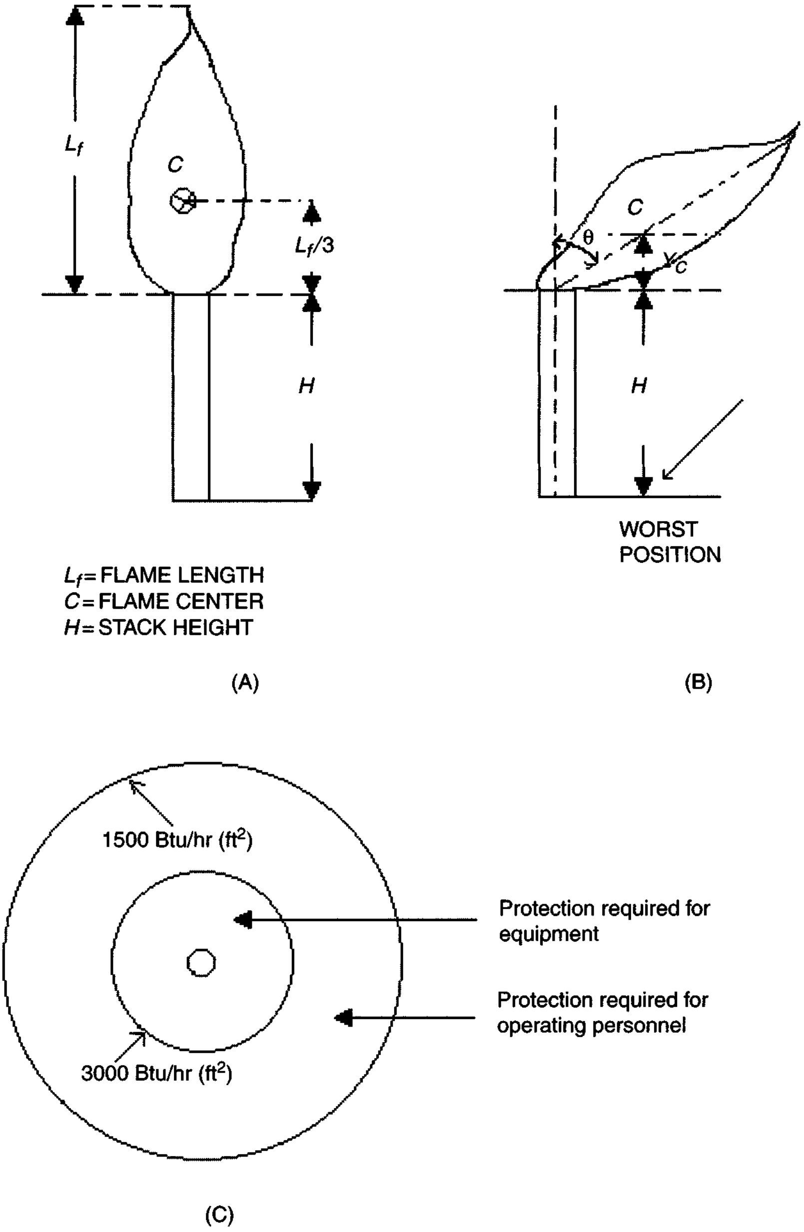
L_f = length of flame, ft;
ΔP = pressure drop, in. water;
D = tip diameter, in.

The center of the flame is assumed to be located a distance equal to one third the length of the flame from the tip.

The angle of the flame results from the vectorial addition of the velocity of the wind and the gas exit velocity (Figure 10-5B):

$$\theta = \tan^{-1}\left(\frac{V_{\text{wind}}}{V_{\text{exit}}}\right)$$

$$V_{\text{exit}} \approx 550\left(\frac{\Delta P}{55}\right)^{0.5} \text{ ft/sec}$$



(A) (B)

(C)

Figure 10-5. Thermal radiation from elevated flares.

and the coordinates of the flame center (located at $L_f/3$), with respect to the flare tip, are

$$X_c = \left(\frac{L_f}{3}\right)\cos\theta$$

$$Y_c = \left(\frac{L_f}{3}\right)\sin\theta$$

The distance from any point on the ground level to the center of the flame is

$$R = \sqrt{(X - X_c)^2 + (Y - Y_c)^2}$$

These equation allow you to determine the radiation intensity over any location.

The worst position for a given gas flow and wind velocity is vertically below the center of the flame (Figure 10-5(B)). For this location,

$$R = [(H + Y_c)^2]^{0.5}$$

or

$$R = H + Y_c$$

$$H = R - Y_c$$

This method assumes that there is no effect of wind on the flame length, which is not true at high wind velocities.

EXPLOSION HAZARD

An explosion could occur in a flare system if the oxygen concentration reaches the lower explosive limit for the gas or vapor contained in the system. Basically, two methods are used to minimize air concentration in the flare system: purging and sealing.

Purging is required during start-up to initially displace air from the flare system or when waste gas flow rate decreases below a certain critical level or stops completely. Any gas can be used, provided it contains no oxygen.

Sealing involves two aspects: Sealing the piping header up to the base of the stack is generally accomplished by a liquid seal drum. The stack is protected by a sealing device placed, ideally, as close to the tip of the flare as possible. The seal should be able to prevent reverse flow due to flow oscillations and thermal contractions.

LIQUID CARRYOVER

Flammable liquid droplets greater than 150 microns should be stopped before reaching the tip of the flare; otherwise, they can be dangerously projected over the surrounding area as a burning rain. During normal flaring conditions, which are usually low flow rates, a simple settling-chamber-type knockout drum is completely effective in removing the liquid droplets. However, during emergency flaring conditions, drums of excessively large diameter are required to knock out liquid particles.

POLLUTION CONTROL

Sometimes, flared gas or its combustion products could be toxic. In these cases, the stack is designed to ensure ground-level concentration below the safe limit, even for the worst possible situation—that is, flame out. Typical norms for emission of sulfur dioxide, particulate matter, carbon monoxide, and so forth, with which refineries must comply by choosing the appropriate technology for processing units, sulfur recovery, refinery fuel, and stack height are shown in Table 10-7.

Igniter reliability contributes to minimizing possible release of unburned hydrocarbons. The flare tip and the pilot must be capable of sustaining a stable flame and positive ignition even under the most severe winds. This capability is achieved by special devices, such as flare and pilot windshields. The highest reliability is obtained from flame front igniters, which automatically adjust for changes in the properties of the igniter gas/air mixture.

SMOKELESS FLARE

Smokeless flaring is based on the principle of increasing the burning rate by the injection of steam into a flame, creation of turbulence in the

Table 10-7
Ambient Air Quality Standards

PARAMETER	TYPICAL REFINERY STANDARDS	U.S. STANDARDS
SULFUR DIOXIDE	0.03 ppm ANNUAL ARITHMETIC MEAN	0.03 ppm ANNUAL ARITHMETIC MEAN
	0.14 ppm MAX 24-hr CONCENTRATION	0.14 ppm MAX 24-hr CONCENTRATION
PARTICULATE MATTER	0.075 mg/m^3 ANNUAL ARITHMETIC MEAN	0.05 mg/m^3 <10 MICROGRAM SIZE ANNUAL ARITHMETIC MEAN
	0.286 mg/m^3 24-hr CONCENTRATION ONCE/yr	0.15 mg/m^{3}MICROGRAM SIZE 24-hr AVERAGE
CARBON MONOXIDE	9 ppm 8-hr AVERAGE CONCENTRATION ONCE/yr	9 ppm 8-hr AVERAGE CONCENTRATION ONCE/yr
	35 ppm 1-hr, AVERAGE CONCENTRATION, ONCE/yr	35 ppm 1-hr, AVERAGE CONCENTRATION ONCE/yr
OZONE	0.08 ppm, 1-hr TOTAL/yr	0.12 ppm, 1-hr TOTAL/yr
NITROGEN DOXIDE	0.05 ppm, ANNUAL ARITHMETIC MEAN	0.053 ppm, ANNUAL ARITHMETIC MEAN
	0.25 ppm MAX, 24-hr CONCENTRATION	
LEAD	10 MICROGRAM/m^3, 30-DAY AVERAGE CONCENTRATION	1.5 MICROGRAM/m^3, QUARTERLY ARITHMETIC MEAN
VOLATILE ORGANIC COMPOUNDS	0.1 ppm FOR 1 hr	NO STANDARD

reacting gases, and the inspiration of air, thereby reducing the formation of soot. Soot formation is also reduced by a water/gas reaction:

$$C + H_2O = CO + H_2$$

The tendency of the hydrocarbon vapor to smoke when burned depends on its molecular structure, degree of unsaturation, and molecular weight. The products of combustion are mainly steam and carbon dioxide. The higher the molecular weight of the hydrocarbon, the lower is the ratio of steam to carbon dioxide and greater is the tendency to smoke. The rate of steam to the flare is automatically controlled to avoid excessive steam usage and ensure continued smokeless operation. Typical values for steam or fuel gas are 0.15–0.5 lb/lb hydrocarbon flow

Smokeless operation is obtained by proper flare tip design and optimum use of mechanical energy to induce air mixing with waste gas. The mixing energy can be obtained from the same gas when sufficient pressure is available or from steam.

However, steam is not the only medium that can be used for smokeless flaring. In situations where steam is unavailable, for example, around an offshore rig, other methods must be employed to achieve smokeless flaring.

The use of high pressure assist gas produces smokeless operation but has several drawbacks: the increased thermal radiation due to addition of the heating value of the high pressure gas and a waste of energy. Gas-assisted flares require approximately 0.15–0.3 lb high pressure gas per pound of waste flare gas.

Direct injection of water, sprayed into the flare, also eliminates smoke. The amount of water required depends on the degree of atomization of water stream. Approximately 1–2 lb water are required for each pound of hydrocarbon vapor. If the molecular weight of the flare gas increases, the amount of water injected also must increase. The degree of atomization of water is an important variable. With a coarse spray, the amount of water required can increase tenfold. Of course, most of this water falls through the flame without being utilized.

FIRED OR ENDOTHERMIC FLARES

Fired or endothermic flares are used for low heat waste streams, such as sulfur plant tail gas, ammonia vapor, and the like. Whenever the heat content of waste gas is below 150 Btu/ft^3, then a fired flare with high energy assist gas is required for complete combustion.

Certain gases, like ammonia, though having a relatively high calorific value of 365 Btu/ft^3, still require assist gas to increase the heat content and ensure complete combustion while minimizing NO_2 production. This is because the fuel-bound nitrogen has a quenching effect on the flare flame and can generate NO_x.

The basic design of fired or endothermic flare depends on the required amount and available pressure of the assist gas. Small flares or flares requiring small amounts of assist gas use inspirating incinerator burners to oxidize the waste gases. For large flares, flares with rings and center injection are used to supply the gas to produce turbulence mixing.

Thermal radiation of the fired flares is quite different from conventional hydrocarbon flares because of the very low heat content and flame temperature. The flame length is approximately 10% shorter than a conventional hydrocarbon flare, while flame emissivity is from 20 to 40% lower.

GROUND FLARES

Enclosed ground flares conceal the flame and provide smokeless operation without steam injection. By eliminating steam, one source of noise is completely removed. Combustion noise is also reduced by using many small burners and many small individual flames. The combustor is lined with an acoustically absorbent high-temperature ceramics to reduce the combustion noise. The combustion air inlet is acoustically shrouded and baffled to reduce noise outside the unit. The main disadvantages of ground flares are the larger ground area required and high initial cost. However, they provide the best overall control of noise and combustion problems and offer best solution for performance and reliability.

A refinery may have both elevated and ground flares (Figure 10-6). In this case, safe disposal of a normal load is achieved by knocking down the heavy ends and condensables in the flare knockout drum and burning the gases in an elevated stack. A controlled amount of steam is used to ensure smokeless burning. A water seal is used to prevent flame flashback.

In emergency loads, the high rate of gas flowing through the common header causes the flow to be partly diverted to a ground flare and, after passing through a ground flare water seal, are burned off in the ground flare.

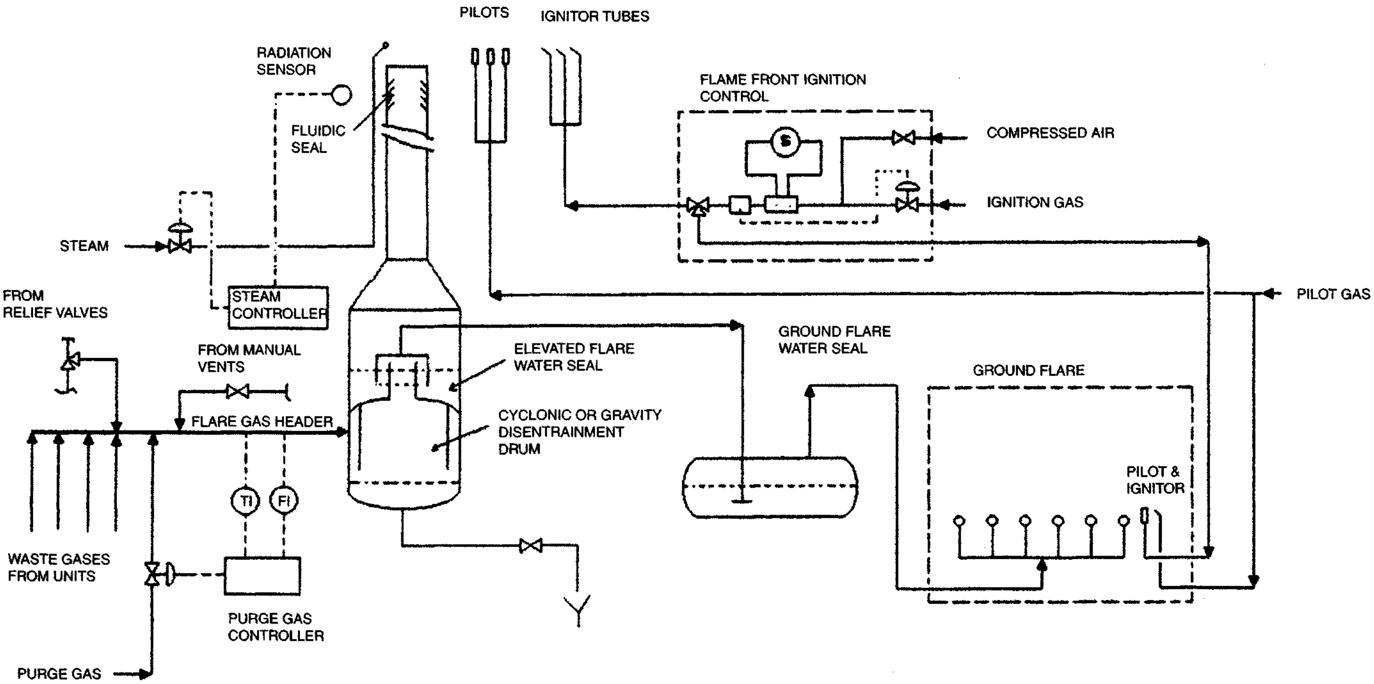


Figure 10-6. Flare system with elevated and ground flares. TI = temperature indicator; FI = flow indicator.

REFINERY STEAM SYSTEM

Roughly 10% of the crude throughput of the refinery ends up as refinery fuel. Steam generation alone accounts for about one third of the refinery total fuel consumption. The generation and distribution of steam and electrical power constitute a major part of a refinery's utility system.

There are three broad categories of usage of steam in the refineries:

1. *Heating loads.* These are usually well defined. Included in this category is steam for heat exchangers, reboilers, steam tracings, and off-site and utility plant heating. Variation in feedstock quality and throughput can sometimes result in maximum and minimum loads.
2. *"Process" or open steam loads.* These loads include fractionators, stripping steam, vacuum jet ejectors, spargers, smokeless flares, fuel atomizing steam, and the like. Included in this category could also be heating steam in remote areas where condensate return is not justified.
3. *Power loads.* These loads are represented by turbine drivers on pumps, compressors, generators, and so forth. Loads include turbines driven for reasons of reliability, economy, control, emergency coverage, and so on. These can be termed *fixed requirements.*

STEAM GENERATION AND DISTRIBUTION

Steam for refinery use can be generated from one or more of these following sources: fired steam or unfired steam generators, turbine exhaust or extraction. Figure 10-7 shows the general design principles for establishing refinery steam systems. The steam system consists of steam generators and a distribution network at different pressure levels for process and utility requirements.

The feed is a mixture of condensate and de-mineralized water which is deaerated before being fed to the boilers. The product is high-pressure steam, typically at 900 psig, depending on the end use of the steam. Many process units, such as hydrogen and sulfur plants, have waste heat boilers; and these also generate high-pressure steam. Only boiler feedwater is supplied to these unfired steam generators. The product HP (900 psig) steam is sent to an HP steam header.

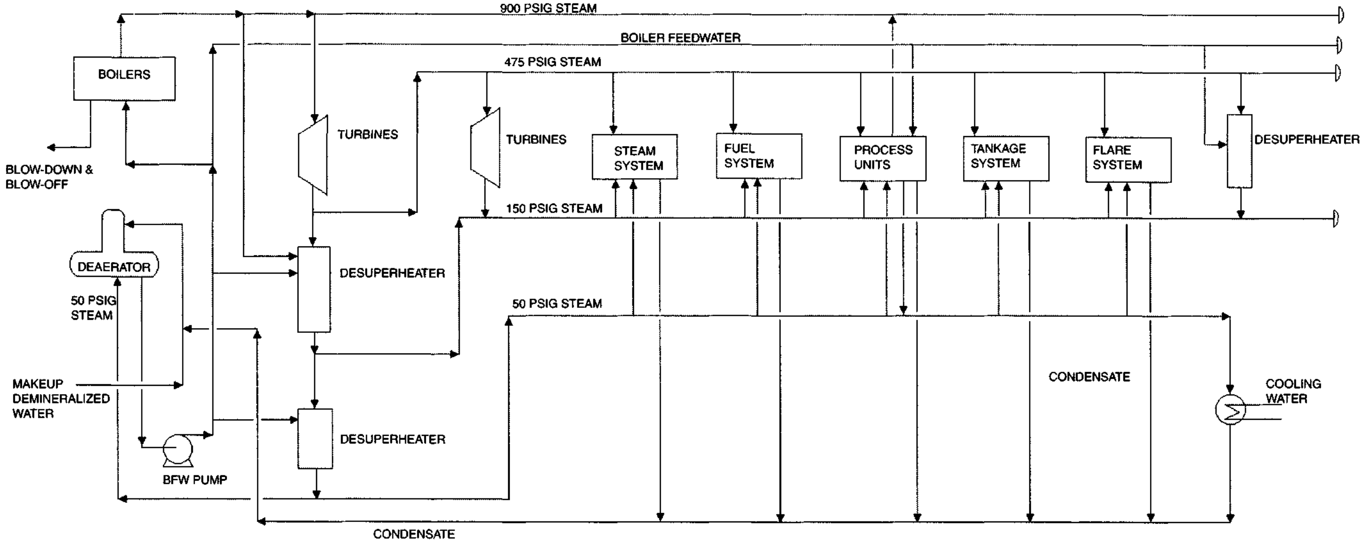


Figure 10-7. Refinery steam system. BFW = boiler feedwater.

Typically four types of headers are used for steam distribution in a refinery. In refineries with in-house power generation (Figure 10-8), steam is generated at a higher pressure of approximately 1450 psig instead of 900 psig, which increases the efficiency of power generation and thus lowers per unit cost of power produced. The four headers are as follows:

1. *900 psig*. Steam is supplied to the 900 psig header from the boiler plant. Some process units, such as hydrogen and sulfur plants, have waste heat boilers that also generate steam at 900 psig. The 900 psig steam is consumed by steam turbines to drive recycle compressors, charge pumps, and the like for many hydroprocessing units of the refinery and as makeup to 475-psig header through a reducing or desuperheating station.
2. *475 psig*. Sources of 475 psig steam are the exhaust steam of turbines and makeup from the 900 psig steam header. The 475 psig steam is consumed in steam turbines, reboilers, and certain process plants, such as hydrogen. All excess 475 psig steam is reduced and desuperheated to a 150 psig header.
3. *150 psig*. Sources of 150 psig steam are steam turbine exhaust, waste heat boilers in the process units, and makeup from 475 psig steam. The consumers are process stripping, reboilers, and steam tracing. All excess 150 psig steam is reduced and desuperheated to 50 psig steam header.

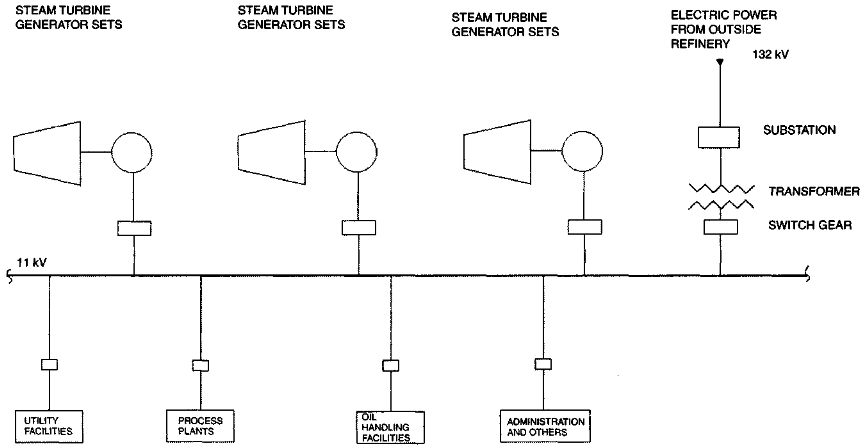


Figure 10-8. Refinery electrical system.

4. *50 psig*. Sources of 50 psig steam are steam turbine exhaust, waste heat boilers in certain process plants (sulfur plant condensers), boiler plant FD fans, and from 150 psig steam reduction and desuperheating. The 50 psig steam is consumed for process steam stripping, reboilers, and steam tracing. All excess 50 psig steam is condensed and returned to the reboiler feedwater.

NORMAL AND PEAK STEAM DEMAND

Normal steam demand at different pressure levels can be estimated by adding together the demand of the individual process units of the refinery. Steam demand for off-site areas is similarly estimated. To this is added the following:

1. Demand of steam for major equipment, which must be steam driven.
2. The quantities of steam generated by waste heat boilers (negative demand).
3. The exhaust steam demand for heating the building and off-site areas.
4. The exhaust steam demand for atomizing fuel and for deaerators.

In typical refineries, where most of the power is purchased and motors are backed up with turbines, the major peak load occurs during power failure. The other intermittent and emergency load may be for unit start-up. In colder climates, the winter heating load frequently overrides other factors, and the possibility of a winter power failure often fixes the maximum steam requirement. Elsewhere, the maximum boiler steam requirement might be set for peak start-up demand, a turnaround in which a major waste heat steam generator is down.

BOILER CAPACITY

Steam is preferably generated in multiple steam generators instead of one or two large-capacity boilers, and the boilers have a total installed capacity no less than 133% of normal requirements. All steam boilers are considered to be operating at partial load to supply normal refinery requirements. Multiple boiler units have more flexibility to match demand with supply of steam in the refinery due to variations in throughput or shutdown of any processing unit.

The total installed capacity must also equal at least the emergency steam requirements of the refinery. An additional factor to be considered is shutdown of the boilers. When a unit is out of service, the remaining units should be capable of fulfilling the process and off-site steam requirements of the refinery without the need for any emergency shutdown of any process unit.

The design conditions for an individual boiler and associated piping and auxiliaries should equal the rated capacity of the boiler. The emergency design conditions for each boiler should be equal to 110% of the rated capacity of the boiler, with pressure and temperature assumed equal to those at design conditions. The design pressure of boilers is 10% greater than the maximum operating pressure but no less than 25 psi in excess of this pressure.

COST OF STEAM GENERATION

The cost of steam generation is basically the cost of energy contained in steam. Steam boilers consume a the large percent of refinery total fuel consumption. Typical utility consumption per metric tonne of HP steam raised is presented in Table 10-8.

In addition to fuel, power, boiler feedwater, and cooling water, steam boilers require minor amounts of certain chemicals (caustic soda, soda

Table 10-8
Utility Consumption for Steam Boilers per Tonne HP (900 psig) Steam

UTILITY	UNITS	CONSUMPTION
FUEL	mmBtu	3.319
STEAM	mmBtu	0.176
ELECTRICITY	kWhr	4.848
DEMINERALIZED WATER	MIG*	0.088
COOLING WATER	MIG*	0.018
ASSUMPTIONS		
HEAT CONTENT OF BOILER FEEDWATER 20 psi AND AT 250°F	mmBtu	0.4408
HEAT CONTENT OF BOILER STEAM AT 900 psig AND AT 810°F	mmBtu	3.0856
HEATING EFFICIENCY OF BOILER	%	85
COST OF CHEMICALS EXCLUDED		

*MIG = 1000 IMPERIAL GALLONS.

ash, sodium phosphates, and hydrazine). The cost of chemicals, although small compared to energy cost, nevertheless must be taken into consideration in estimating the cost per tonne of steam.

The cost of steam at lower pressures is taken equal to high-pressure steam if lower-pressure steam is generated simply by pressure reduction of high-pressure steam. If lower-pressure steam is obtained through power turbines, the marginal value of steam equals high-pressure steam less the cost of power generated.

REFINERY FUEL SYSTEM

Heating may be required in the refinery at a number of places for various process applications and steam generation in its utility plant. Burning fuel provides the necessary heat. The refinery fuel system includes facilities for the collection, preparation, and distribution of fuel to users. The commonly used refinery fuels are fuel oil and gas. On average, for every 100 barrels of crude processed in the refinery, 10 barrels are used as refinery fuel.

FUEL SELECTION

Fuel gas and residual fuel are the most commonly used fuels in the refinery. Other refinery products of low monetary value, such as heavy pitch residues, visbreaker tars, FCCU decanted oil, vacuum tower bottoms from certain crudes, lube extracts, and waxes are also used as fuel in the refinery itself. The majority of these materials would be difficult to blend in a commercial fuel of acceptable specifications because of high viscosity, chemical aggressiveness, high contaminant level (sulfur, metals, etc.), and associated environmental problems in their use.

Gaseous streams diverted to the refinery as fuel are those gases that cannot be processed to saleable products economically. These include H_2, CH_4, C_2H_6, and frequently C_3 and C_4 gases. In a refinery of average complexity, approximately two thirds of refinery fuel requirements may come from refinery gases. The rest of the fuel requirement is made up from a natural gas supply, if available, or residual fuel oil produced in the refinery.

In many refineries, both gaseous and liquid fuels are used simultaneously. Furnaces and boilers are equipped with combination burners, suitable for both gas and oil firing. Exception to this are certain refinery units, such as cat reforming, where only gas firing is permissible because of the need for precise temperature control. Furnaces that are operated when no gaseous fuel is available as during refinery start up must be equipped with oil burning capability.

REFINERY FUEL OIL SYSTEM

The purpose of refinery fuel oil system is to ensure a constant, regular supply of oil to burners of steam boilers and to process furnaces. The system includes facilities for storage, pumping, heating, and distribution of oil at suitable pressure and viscosities so that the atomization and burning of oil is possible. A typical refinery home fuel system is shown in Figure 10-9. The aim of the fuel oil system design is that operational changes to one furnace will not cause fluctuation of supply to another portion of the refinery.

Storage is an essential need, which must be met with availability of at least 5 days supply at normal firing rate of the furnaces and boilers, which are usually oil fired. This may require one or more tanks for storage. If the refinery fuel is obtained from more than one source, it may be necessary to store the blended material, too, and so more than one tank may be required. It is often possible to line blend the various fuel components as these leave their units without the need for intermediate storage. Precise blending control is not required. Oil is delivered to the burner at a pressure of approximately 100 psig for control and atomization. To

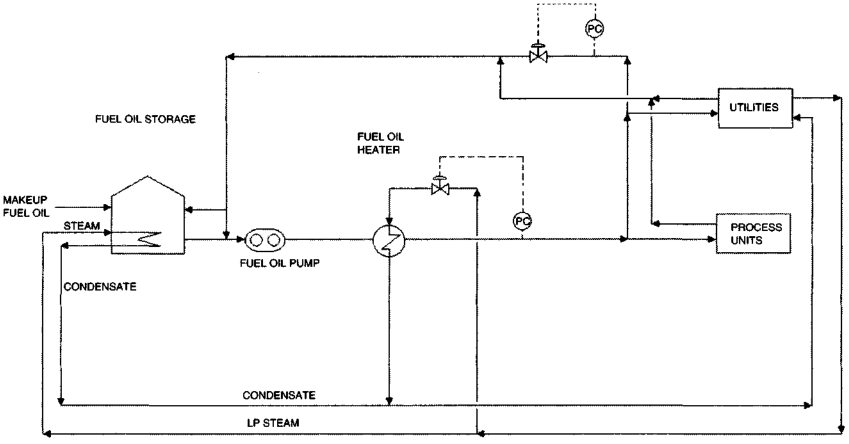


Figure 10-9. Refinery home fuel (liquid) system. LP = low pressure; PC = pressure controller.

provide this pressure at the burner and allowing for pressure drop in the lines, oil is pumped from storage at 120–150 psig.

The temperature at which fuel oil is discharged from fuel oil storage varies with the material being pumped. For proper atomization, the temperature at which oil is being pumped should be sufficient to lower the viscosity of oil to 30–40 centistokes.

The design capacity of fuel oil heating and pumping equipment usually equals 125% of the design requirement of the plant, assuming simultaneous firing at the design rate of all fuel oil burning furnaces and boilers. This allows for 25% recirculation of oil. Rotary pumps are used, one driven by electric motor and the other by steam turbine. Heaters used are steam heaters. Relief valves are located on the discharge side of the pumps and on oil heaters. Relief valve discharge is piped back to storage tank. Strainers are provided at the pump inlet and outlet to strain out any precipitated carbon particles. Piping from the suction line to the fuel oil pumping equipment is sized for a pressure drop not exceeding 3 psi/1000 ft. The discharge piping supplying burners and recirculation piping returning to storage have protective heating. Separate nozzles are provided on storage tanks for makeup fuel and for recirculation and withdrawal of oil.

REFINERY FUEL GAS SYSTEM

The refinery fuel gas system is designed to supply fuel gas to steam boilers, process furnaces, gas engines, and gas turbines at a regulated pressure and reasonably constant heating value. The system includes mixing drum controls and distribution piping. Wherever necessary, a stand by storage of liquefied petroleum gas (LPG) is included. A typical refinery fuel gas system is shown in Figure 10-10.

The mixing gas drum is typically operated at 30 to 40 psig, which allows for delivery of gas at burners approximately 15–20 psig. For refineries with an operating gas turbine, the drum pressure is much higher, at 125 psig. The mixing vessel is fitted with mixing baffles and a steam coil for vaporizing any liquid carryover or LP gases. Refinery gas burners are designed for a particular heating value and gas density. The composition of gas to the gas mixing drum is so adjusted that large changes in calorific value or density of gas to various refinery furnaces are avoided. For example, it may not be possible to replace refinery gases with high calorific value and density totally with natural gas with lower calorific value and density without affecting performance of the furnaces using them.

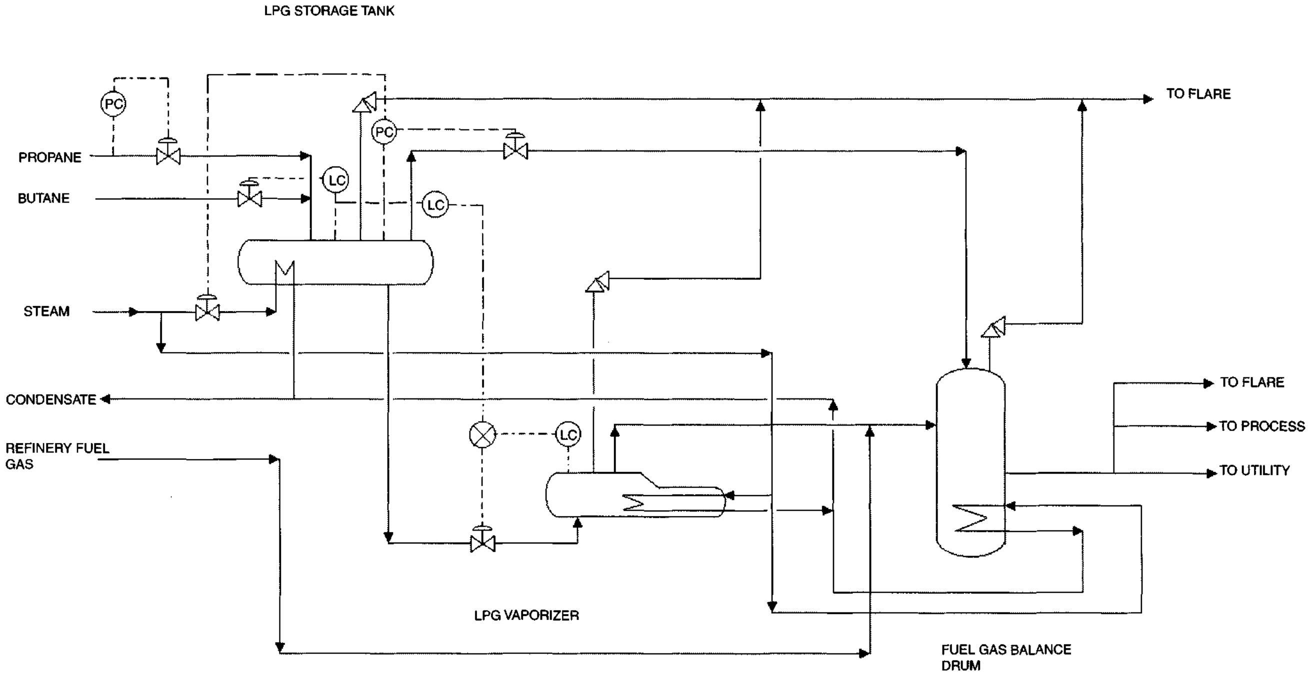


Figure 10-10. Refinery home fuel (gas) system.

NOTES

1. T. A. Brzustowski and E. C. Sommer, Jr. "Predicting Radiant Heating from Flares," *Proceedings of the Division of Refining, A.P.I.* 53 (1973), pp. 865–893.
2. J. F. Straitz and R. J. Altube. "Flare Design and Operation." National Airoil Burner Company (USA) bulletin.