

Electrical Installations in Petroleum Processing Plants

API RECOMMENDED PRACTICE 540
FOURTH EDITION, APRIL 1999

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Electrical Installations in Petroleum Processing Plants

Downstream Segment

API RECOMMENDED PRACTICE 540
FOURTH EDITION, APRIL 1999



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FOREWORD

This recommended practice provides information on electrical installations in petroleum facilities. It is intended for all individuals and organizations concerned with the safe design, installation, and operation of electrical systems in petroleum facilities.

This recommended practice has been developed by individuals with many years' experience in the petroleum industry. Although of interest to anyone seeking information on electrical systems in petroleum facilities, it is primarily intended to be used by individuals knowledgeable in engineering fundamentals who require specific guidance concerning currently accepted practices in the petroleum industry.

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Certain serious adverse health effects are associated with asbestos, among them the serious and often fatal diseases of lung cancer, asbestosis, and mesothelioma (a cancer of the chest and abdominal linings). The degree of exposure to asbestos varies with the product and the work practices involved.

Consult the most recent edition of the Occupational Safety and Health Administration (OSHA), U.S. Department of Labor, Occupational Safety and Health Standard for Asbestos, Tremolite, Anthophyllite, and Actinolite, 29 *Code of Federal Regulations* Section 1910.1001; the U.S. Environmental Protection Agency, National Emission Standard for Asbestos, 40 *Code of Federal Regulations* Sections 61.140 through 61.156; and the U.S. Environmental Protection Agency (EPA) rule on labeling requirements and phased banning of asbestos products (Sections 763.160-179).

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Electrical Installations in Petroleum Processing Plants

SECTION 1—INTRODUCTION

1.1 PURPOSE

This recommended practice provides information on electrical installations in petroleum facilities. Petroleum processing requires specialized equipment that continually processes, often at high rates and elevated temperatures and pressures, liquids, and gases that undergo both chemical and physical changes. Consequently, it is necessary that electrical installations and equipment in petroleum facilities be designed to prevent accidental ignition of flammable liquids and gases.

To maintain safety and operating continuity, requirements for the electrical systems in petroleum facilities are more stringent than those for most other manufacturing facilities. This recommended practice addresses specific requirements for those electrical systems.

1.2 SCOPE

This recommended practice is limited to electrical installations in petroleum facilities. It provides a basis for specifications included in engineering and construction contracts. Electrical equipment test standards are excluded from the scope of this recommended practice. Operation and maintenance are addressed only insofar as they affect electrical system design and electrical equipment selection. The subject of energy conservation is reviewed.

1.3 REFERENCES

1.3.1 The following standards, codes, and specifications are cited in this recommended practice:

API

- RP 14F *Design and Installation of Electrical Systems for Offshore Production Platforms*
- RP 500 *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2*
- RP 505 *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2*
- Std 541 *Form-Wound Squirrel-Cage Induction Motors—250 Horsepower and Larger*
- Std 546 *Brushless Synchronous Machines—500 kVA and Larger*
- RP 552 *Recommended Practice for Transmission Systems*

- Std 610 *Centrifugal Pumps for Petroleum, Heavy Duty Chemical and Gas Industry Service*
- Std 614 *Lubrication, Shaft-Sealing, and Control-Oil Systems and Auxiliaries for Petroleum, Chemical and Gas Industry Service*
- RP 651 *Cathodic Protection of Aboveground Storage Tanks*
- RP 2001 *Fire Protection in Refineries*
- RP 2003 *Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents*

AEIC¹

- CS1 *Specification for Impregnated Paper-Insulated, Lead-Covered Cable, Solid Type*
- CS5 *Specifications for Thermoplastic and Crosslinked Polyethylene Insulated Shielded Power Cables Rated 5 Through 46 kV*
- CS6 *Specifications for Ethylene Propylene Rubber Insulated Shielded Power Cables Rated 5 Through 69 kV*

AGMA²

- 6019-E *Gearmotors Using Spur, Helical, Herringbone, Straight Bevel, or Spiral Bevel Gears*

ANSI³

- C80.1 *Specification for Rigid Steel Conduit, Zinc Coated*
- C80.5 *Specification for Rigid Aluminum Conduit*
- C84.1 *Electric Power Systems and Equipment Voltage Ratings (60 Hz)*

ASTM⁴

- D877 *Standard Test Method for Dielectric Breakdown Voltage of Insulating Liquids Using Disk Electrodes*

CSA⁵

- Canadian Electrical Code*

¹Association of Edison Illuminating Companies, P.O. Box 2641, Birmingham, Alabama 35291.

²American Gear Manufacturers Association, 1500 King Street, Suite 201, Alexandria, Virginia 22314.

³American National Standards Institute, 1430 Broadway, New York, New York 10018.

⁴American Society of Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959.

⁵Canadian Standards Association, 178 Rexdale Boulevard, Rexdale, Ontario M9W 1R3, Canada.

EPA ⁶	"Polychlorinated Biphenyls (PCBs) Manufacturing, Processing, Distribution in Commerce, and Use Prohibitions"	Std 841	<i>Recommended Practice for Chemical Industry Severe Duty Squirrel-Cage Induction Motors 600 Volts and Below</i>
40 CFR Part 761		Std 844	<i>Recommended Practice for Electrical Impedance, Induction, and Skin Effect Heating of Pipelines and Vessels</i>
IEEE ⁷	<i>Standard Requirements, Terminology, and Test Procedures for Neutral Grounding Devices</i>	Std 1015	<i>Recommended Practice for Applying Low-Voltage Circuit Breakers Used in Industrial and Commercial Power Systems (Blue Book)</i>
Std 32		Std 1100	<i>Recommended Practice for Powering and Grounding Sensitive Electronic Equipment</i>
Std 80	<i>Guide for Safety in AC Substation Grounding</i>	C2	<i>National Electrical Safety Code</i>
Std 100	<i>Standard Dictionary of Electrical and Electronics Terms</i>	C57.12.00	<i>General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers</i>
Std 141	<i>Recommended Practice for Electric Power Distribution for Industrial Plants (Red Book)</i>	C57.12.01	<i>Standard General Requirements for Dry-type Distribution and Power Transformers Including those with Solid-cast and/or Resin-encapsulated Windings</i>
Std 142	<i>Recommended Practice for Grounding of Industrial and Commercial Power Systems</i>	C57.92	<i>Guide for Loading Mineral-oil-immersed Power Transformers Up to and Including 100 MVA with 55°C or 65°C Average Winding Rise</i>
Std 242	<i>Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (Buff Book)</i>	C57.96	<i>Guide for Loading Dry-Type Distribution and Power Transformers</i>
Std 399	<i>Recommended Practice for Industrial and Commercial Power Systems Analysis (Brown Book)</i>	C57.106	<i>Guide for Acceptance and Maintenance of Insulating Oil in Equipment</i>
Std 422	<i>Guide for the Design and Installation of Cable Systems in Power Generating Stations</i>	C57.111	<i>Guide for Acceptance of Silicone Insulating Fluid and Its Maintenance in Transformers</i>
Std 446	<i>Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications</i>	C57.121	<i>Guide for Acceptance and Maintenance of Less Flammable Hydrocarbon Fluid in Transformers</i>
Std 493	<i>Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (Gold Book)</i>	NACE ⁸	<i>Control of External Corrosion on Underground or Submerged Metallic Piping Systems</i>
Std 515	<i>Standard for the Testing, Design, Installation and Maintenance of Electrical Resistance Heat Tracing for Industrial Applications</i>	RP 0169	
Std 518	<i>Guide for the Installation of Electrical Equipment to Minimize Noise Inputs to Controllers from External Sources</i>	RP 0176	<i>Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production</i>
Std 519	<i>Recommended Practice and Requirements for Harmonic Control in Electric Power Systems</i>	RP 0675	<i>Control of External Corrosion on Offshore Steel Pipelines</i>
Std 576	<i>Recommended Practice for Installation, Termination, and Testing of Insulated Power Cable as Used in the Petroleum and Chemical Industry</i>	NEMA ⁹	<i>General Standards for Industrial Control and Systems</i>
		ICS 1	
		ICS 6	<i>Enclosures for Industrial Controls and Systems</i>
		MG 1	<i>Motors and Generators</i>

⁶United States Environmental Protection Agency/National Center for Environmental Publications, P.O. Box 42419, Cincinnati, Ohio 45242-2419.

⁷Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08855-1331.

⁸NACE International, 1440 South Creek Drive, Houston, Texas 77084.

⁹National Electrical Manufacturers Association, 1300 North 17th Street, Suite 1847, Rosslyn, Virginia 22209.

MG 2	<i>Safety Standard for Construction and Guide for Selection, Installation and Use of Electric Motors and Generators</i>	UL ¹¹ 674	<i>Electric Motors and Generators for Use in Hazardous Locations, Class I, Groups C and D, Class II, Groups E, F, and G</i>
WC 3	<i>Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy</i>	698	<i>Industrial Control Equipment for Use in Hazardous (Classified) Locations</i>
WC 5	<i>Thermoplastic-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy</i>	913	<i>Intrinsically Safe Apparatus and Associated Apparatus for Use in Hazardous (Classified) Locations</i>
WC 7	<i>Cross-Linked-Thermosetting-Polyethylene-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy</i>	1242	<i>Intermediate Metal Conduit</i>
WC 8	<i>Ethylene-Propylene-Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy</i>	1.3.2 The following publications are not specifically referenced in this recommended practice, but provide guidance in the design of electrical systems for petroleum facilities:	
NFPA ¹⁰	<i>Fire Protection Handbook</i>	IEEE ⁷ Std 493	<i>Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems</i>
	30 <i>Flammable and Combustible Liquids Code</i>	Std 739	<i>Recommended Practice for Energy Conservation and Cost Effective Planning in Industrial Facilities</i>
	37 <i>Standard for Stationary Combustion Engines and Gas Turbines</i>		
	54 <i>Fuel Gas Code</i>	IES ¹² RP 7	<i>Practice for Industrial Lighting Handbook</i>
	69 <i>Explosion Prevention Systems</i>	ISA ¹³ RP 12.1	<i>Definitions and Information Pertaining to Electrical Instruments in Hazardous Locations</i>
	70 <i>National Electrical Code</i>	S12.4	<i>Instrument Purging for Reduction of Hazardous Area Classification</i>
	70E <i>Electrical Safety Requirements for Employee Workplaces</i>	RP 12.6	<i>Installation of Intrinsically Safe Systems for Hazardous (Classified) Locations</i>
	77 <i>Recommended Practice on Static Electricity</i>	S12.13,	Part I, <i>Performance Requirements, Combustible Gas Detectors</i>
	90A <i>Standard for the Installation of Air Conditioning and Ventilating Systems</i>	RP 12.13,	Part II, <i>Installation Operation and Maintenance of Combustible Gas Detection Instruments</i>
	91 <i>Standard for Exhaust Systems for Air Conveying of Materials</i>	Note: Includes former Bureau of Mines Bulletin 627, <i>Flammability Characteristics of Combustible Gases and Vapors</i> (no longer in print).	
	110 <i>Emergency and Standby Power Systems</i>	S12.16	<i>Electrical Apparatus for Use in Class I, Zone 1 Hazardous (Classified) Locations: Type of Protection—Increased Safety “e”</i>
	325 <i>Guide to Fire Hazard Properties of Flammable Liquids, Gases, and Volatile Solids</i>	S12.24.01	<i>Electrical Apparatus for Explosive Gas Atmospheres, Classifications of Hazardous (Classified) Locations</i>
	496 <i>Standard for Purged and Pressurized Enclosures for Electrical Equipment</i>		
	497 <i>Classification of Flammable Liquids, Gases, or Vapors and of Hazardous Classified Locations for Electrical Installations in Chemical Process Areas</i>		
	499 <i>Classification of Combustible Dusts and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas</i>		
	780 <i>Lightning Protection Code</i>		

¹⁰National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02269.

¹¹Underwriters Laboratories, Inc., 333 Pfingsten Road, Northbrook, Illinois 60062.

¹²Illuminating Engineering Society of North America, 120 Wall Street, Floor 17, New York, New York 10005-4001.

¹³International Society for Measurement and Control (ISA), P.O. Box 12277, Research Triangle Park, North Carolina 27709-2277.

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| <p>S51.1 <i>Process Instrumentation Technology</i></p> <p>David N. Bishop, <i>Electrical Systems for Oil and Gas Production Facilities</i>,</p> <p>P. J. Schram and M. W. Earley, <i>Electrical Installations in Hazardous Locations</i></p> <p>Ernest C. Magison, <i>Electrical Instruments in Hazardous Locations</i></p> <p>D. G. Fink and H. W. Beaty, <i>Standard Handbook for Electrical Engineers</i> (12th ed.), McGraw-Hill, New York, 1987</p> | <p>NFPA¹⁰</p> <p>499 <i>Classification of Combustible Dusts and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas</i></p>
<p>OSHA¹⁴</p> <p>29 CFR</p> <p>Part 1910 <i>Occupational Safety and Health Standards</i></p> <p>Part 1929.K <i>Electrical Standards for Construction</i></p> |
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| <p>NACE⁹</p> <p>RP 0176 <i>Corrosion Control of Steel Fixed Offshore Platforms Associated With Petroleum Production</i></p> <p>RP 0675 <i>Control of External Corrosion on Offshore Steel Pipelines</i></p> | <hr style="width: 20%; margin-left: 0;"/> <p>¹⁴Occupational Safety and Health Administration, U.S. Department of Labor, 200 Constitution Avenue, N.W., Washington, D.C. 20210. The <i>Code of Federal Regulations</i> is available from the U.S. Government Printing Office, Washington, D.C. 20402-9325.</p> |
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SECTION 2—CLASSIFIED LOCATIONS OR ELECTRICAL EQUIPMENT

2.1 PURPOSE

This section briefly reviews the classification of flammable liquids and gases, the classification of locations where fire or explosion hazards may exist due to flammable gases or vapors, or flammable liquids, and the application of electrical equipment in classified locations.

2.2 SCOPE

This section discusses only the general guidelines pertaining to the classification of locations. A more detailed discussion of the classification of locations can be found in API RP 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2* and API RP 505, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2*.

2.3 CLASSIFICATION OF FLAMMABLE AND COMBUSTIBLE LIQUIDS AND GASES

Note: Classifications used for defining liquids and gases should not be confused with the NFPA 70 classifications used for hazardous (classified) locations.

2.3.1 Definition of Flammable Liquids

As defined by NFPA 30, flammable liquids are liquids that have a flash point below 37.8°C (100°F) and a vapor pressure not exceeding 276 kilopascals absolute (40 pounds per square inch absolute) at 37.8°C (100°F). These liquids are divided into the following general classes:

- Class IA includes the liquids that have flash points below 22.8°C (73°F) and boiling points below 37.8°C (100°F).
- Class IB includes the liquids that have flash points below 22.8°C (73°F) and boiling points at or above 37.8°C (100°F).
- Class IC includes the liquids that have flash points at or above 22.8°C (73°F) and boiling points below 37.8°C (100°F).

2.3.2 Definition of Combustible Liquids

As defined by NFPA 30, combustible liquids are liquids that have flash points at or above 37.8°C (100°F). These liquids are also divided into general classes:

- Class II includes the liquids that have flash points at or above 37.8°C (100°F) and boiling points below 60°C (140°F).
- Class III includes the liquids that have flash points above 60°C (140°F), and Class III liquids are subdivided as follows:
 - Class IIIA includes the liquids that have flash points at or above 60°C (140°F) and boiling points below 93.3°C (200°F).

- Class IIIB includes the liquids that have flash points at or above 93.3°C (200°F).

2.3.3 Flammable Gases—Lighter-than-Air

Lighter-than-air gases that commonly are encountered include methane and a mixture of methane with small quantities of low-molecular-weight hydrocarbons, the mixtures generally being lighter-than-air. Hydrogen must be given a special mixture consideration because of its properties: a wide flammable (explosive)-mixture range, a high flame-propagation velocity, a low vapor density, a low minimum-ignition-energy level, and a relatively high ignition temperature [585°C (1085°F)].

2.3.4 Flammable Gases—Heavier-than-Air

Liquefied petroleum gases include propanes, butanes, and mixtures of the two having densities from 1.5 times to approximately 2.0 times that of air. Vapor pressures of these gases exceed 276 kilopascals absolute (40 pounds per square inch absolute) at 37.8°C (100°F).

2.4 CLASSIFICATION OF LOCATIONS

The National Electrical Code, NFPA 70, has established criteria for classifying locations that do or may contain flammable gases or vapors, flammable liquids, combustible dust, or ignitable fibers or flyings. Once a location has been classified, NFPA 70 specifies equipment requirements for each particular classification. The major effort involved in classifying a location is determining whether flammable gases are likely to exist in the location to be classified and, if they may exist, under what conditions and for how much of the time.

A Class I location is a location in which flammable gases or vapors are or may be present in the air in quantities sufficient to produce explosive or ignitable mixtures. NFPA 70 recognizes two systems for the classification of Class I locations, the Division system and the Zone system. In the Division system, Class I locations are subdivided into Division 1 and Division 2. Division 1 indicates that a flammable mixture may be present under normal operating conditions, and Division 2 indicates that a flammable mixture may be present only in the event of abnormal operating conditions or equipment malfunction. In the Zone system, Class I locations are subdivided into Zone 0, Zone 1, and Zone 2. In a similar manner to the Division system, NFPA 70 contains criteria for defining Zones based on the possibility of releases. In both systems, locations that are not classified as Division 1, Division 2, Zone 0, Zone 1, or Zone 2 are termed unclassified.

Once the existence and degree of ignitable substances in an area has been determined, the physical boundaries of the classified location must be determined. The most important factor to consider is that flammable gas or vapor alone will not produce an ignitable atmosphere; flammable gas or vapor must mix with a sufficient amount of air to become ignitable. Other factors to consider are the quantity and physical characteristics of whatever substance might be liberated and the natural tendency of gases or vapors to disperse in the atmosphere.

Once established, a location's classification and boundaries can be drawn on a plot plan of the process equipment for a given area. Such a drawing is a convenient reference source when selecting electrical equipment for and locating it in the classified area. The classification is incomplete until the dimensions around a source of liquid or gas are defined and documented. Typical height, width, and length dimensions are available in API RP 500 and 505 as well as NFPA 497.

API RP 500 and 505 are practical guides that specifically apply the NFPA 70 classification criteria to electrical installations in petroleum facilities. The recommended practices cover the factors that must be considered in area classification; they provide a questionnaire-type procedure for determining the proper classification of a location; and they illustrate methods for establishing the degree and extent of a location to be classified.

Sound judgment must accompany the use of the recommendations in API RP 500 and RP 505. When, in the opinion of a qualified person, particular conditions are better or worse than average, the pertinent recommendations should be modified accordingly.

2.5 ELECTRICAL EQUIPMENT FOR CLASSIFIED LOCATIONS

Each location in a petroleum facility that is classified must be carefully evaluated to ensure that proper electrical equipment is selected. Most classified atmospheres in petroleum facilities are Class I, Group D; however, certain areas may involve other classes and groups: in particular, Class I, Groups B and C and Class II, Group F. (See NFPA 70 and NFPA 499 for further discussion of Class II locations. See NFPA 70 and 497 for the correlation of material groupings for Division and Zones) To comply with NFPA 70, electrical equipment suitable for the specific area classification must be used.

One indication that electrical equipment installed in classified locations is suitable for the defined locations is that it is approved by a Nationally Recognized Testing Laboratory (NRTL). Certain electrical equipment, such as induction motors for installation in Division 2 and Zone 2 areas, are specifically permitted in NFPA 70 and do not require specific markings or NRTL approvals for use in classified areas.

2.6 ALTERNATIVE DESIGN IN CLASSIFIED LOCATIONS

For applications where it is necessary to install equipment that is not suitable or available for the classification, the following alternative designs may be utilized. These applications may be desirable because equipment is not suitably manufactured for a particular classification, it is more cost effective to secure the alternative equipment, or design preference prohibits such equipment.

2.6.1 Physical Isolation

Physical isolation is an effective, and perhaps the most commonly used, method for installing electrical equipment not otherwise suitable for classified locations. For example, where motors are located in a classified location, the motor starters and control equipment can be installed outside the classified location. This permits the use of less expensive equipment in locations that are more convenient for maintenance.

2.6.2 Pressurized Rooms and Enclosures

According to NFPA 70, classified locations may be reduced or eliminated by adequate positive-pressure ventilation. Authoritative information on design criteria is provided in NFPA 496. Positive-pressurization and purging are based on the principle that an enclosure or room located in a classified location can be purged with clean air or inert gas at sufficient, continuous flow and positive pressure to reduce the original concentration of flammable gas or vapor to a safe level and to maintain this level.

There are three types of purging, each having specific design requirements:

- Type X purging reduces the classification within an enclosure from Division 1 to unclassified.
- Type Y purging reduces the classification within an enclosure from Division 1 to Division 2.
- Type Z purging reduces the classification within an enclosure from Division 2 to unclassified.

2.6.3 Intrinsically Safe Installations

One approach to the application of electrical equipment in classified locations is to use intrinsically safe devices and wiring methods. This method is used primarily for instrumentation and process control. Intrinsically safe equipment and wiring are incapable of releasing the electrical or thermal energy necessary, under normal or abnormal conditions, to ignite a specific hazardous atmospheric mixture in its most ignitable concentration. Information on the design and evaluation of intrinsically safe equipment and wiring to be used in classified locations is provided in UL 913. Intrinsically safe installations should comply with NFPA 70 Article 504.

2.6.4 Other Alternatives

2.6.4.1 NFPA 70 describes several other acceptable protection techniques for electrical equipment and installations in classified areas. These include: oil immersion, nonincendive, and hermetically sealed.

2.6.4.2 Adequate ventilation methods and the use of combustible gas detection, as defined in API RP 500 and RP 505, are techniques that may allow the reduction of the area classification.

SECTION 3—ELECTRICAL ENERGY EFFICIENCY

3.1 PURPOSE

This section reviews energy efficiency as it applies to the selection of electrical equipment for petroleum facilities and to the application of the equipment in those facilities.

3.2 SCOPE

Electrical efficiency is discussed as a part of the broader concept of energy conservation. The definition of efficiency is given, and design considerations are reviewed for specific types of equipment. Economic evaluation is addressed. Other efficiency related topics, such as power factor and demand control, are briefly discussed. Useful definitions and conversion factors are provided at the end of the section.

3.3 THE ROLE OF ELECTRICAL EFFICIENCY

a. Electrical systems provide an important opportunity for energy conservation. The electrical losses in the distribution and utilization equipment of a refinery power system can range as high as 20%. For a 60 megawatt (MW) facility operating 8,000 hours per year and paying \$0.07 per kilowatt-hour (kWh), the cost of these losses would exceed \$6.5 million per year. A similar plant using an energy efficient electrical design could have 15% fewer losses and save \$1 million per year compared to the less efficient design.

In addition to the direct benefits of increased electrical efficiency, there are also some indirect benefits. Reduced losses in electrical equipment can result in lower operating temperatures and prolonged equipment life. For indoor applications, reduced losses also decrease the heat load on air conditioning equipment.

When considering electrical efficiency, it is also useful to recall that, due to losses in the generation, transmission, and distribution of electricity, a 1 kWh reduction in electrical usage saves the equivalent of 4 to 5 kWh of raw fuel.

3.4 DEFINITION OF EFFICIENCY

Efficiency is defined as the ratio of power output to power input or energy output to energy input:

$$\text{Efficiency} = \frac{\text{Power output}}{\text{Power input}} \text{ or } \frac{\text{Energy output}}{\text{Energy input}} \quad (1)$$

Power output can be related to power losses in equipment by the following:

$$\text{Power output} = \text{Power input} - \text{losses} \quad (2)$$

Therefore, efficiency can also be defined in terms of losses and power input

$$\text{Efficiency} = \frac{\text{Power input} - \text{losses}}{\text{Power input}} \text{ or } = 1 - \frac{\text{losses}}{\text{Power input}} \quad (3)$$

or in terms of losses and power output:

$$\text{Efficiency} = 1 - \frac{\text{losses}}{\text{Power output} + \text{losses}} \quad (4)$$

All the above formulae can be applied to energy by substituting kWh for power. In either case, higher efficiency is achieved by reducing operating losses.

3.5 SPECIFICATION CONSIDERATIONS

The specification of electrical equipment should include consideration for energy efficiency. The operating points for which efficiency data are desired should be specified. Usually $\frac{1}{2}$, $\frac{1}{4}$, and full load data are requested. For large equipment, an efficiency curve should be requested. Guaranteed efficiency values, rather than nominal or average values, should be specified.

An economic evaluation factor (in dollars per kWh) should be included in the specification. See 3.6. Any economic penalty clauses should be clearly stated, and the operating point at which efficiency will be evaluated should be specified.

The testing method to be used for determining efficiency should be stated. Witnessed testing is recommended if economic penalty factors are involved. Payment terms that are to be contingent on receipt of the test results should be clearly stated.

3.6 ECONOMIC EVALUATION

3.6.1 Evaluation Factors

Competitive pressures to reduce the cost of processing have provided an incentive for adding capital investment that can cut the energy cost per barrel processed. The cost of adding new equipment, or replacing inefficient equipment must be offset by future energy cost savings. An economic evaluation is necessary to determine if the equipment costs will be offset by the future energy savings. Energy efficient electrical equipment normally demands a premium price. It is useful to develop a dollar-per-kilowatt factor to determine the value of saved energy for projects at a specific site. Several different methods for developing a \$/kW factor are covered in the following sections.

3.6.2 Simple Payback

The least complex dollar-per-kilowatt factor is based on simple payback, which does not account for the depreciated value of future savings:

$$\$/\text{kW} = ChN (1 - T) \quad (5)$$

where

$\$/\text{kW}$ = profit to the user for reducing power usage by 1 kW,

C = cost of electricity, in dollars per kWh,

h = hours of operation per year,

N = number of years in evaluation period,

T = income tax rate paid by the user.

The use of the factor is demonstrated in the following example. Assume a piece of electrical equipment operates *continuously* at a location where the cost of electricity is \$0.05/kWh, and the desired payback period is 5 years. Income is taxed at a 40% rate. The factor would be calculated as follows:

$$\$/\text{kW} = \frac{\$0.05}{\text{kWh}} \times \frac{8760h}{\text{yr}} \times 5\text{yr} \times (1 - 0.40) = \$1,314/\text{kW} \quad (6)$$

This factor is the expected cost for continuously operating a load of one kW for 5 years. This cost factor is then compared to the ratio of the price premium for high efficiency equipment divided by the loss reduction. If the ratio is less than \$1,314, then it pays to spend the money for the high efficiency equipment. For example, if an energy efficient transformer costs \$4,000 more than a standard transformer, and it reduces the losses by 5 kW, the incremental cost is (\$4,000/5 kW) or \$800/kW. The energy efficient unit should, therefore, be selected.

3.6.3 Time Value of Money

Equation 5 does not take into account the time value of money. Future savings should be adjusted for increases in power costs and the required cost of capital. The following equation provides a dollar-per-kilowatt factor that allows for power cost inflation and desired rate of return on investment.

$$\$/\text{kW} = Ch (1 - T) \frac{1 + i^N - 1}{i(1 + i)^N} \quad (7)$$

where

$\$/\text{kW}$ = profit to the user of reducing power usage by 1 kW,

C = cost of electricity, in dollars per kWh,

h = hours of operation per year,

N = number of years in evaluation period,

T = income tax rate paid by the user,

i = effective interest rate

$$= i = \frac{1 + R_2}{1 + R_1} - 1 \quad (8)$$

R_1 = anticipated annual escalation rate for cost of electricity,

R_2 = desired annual rate of return on investment.

Using the example of equation 5 along with a 15% rate of return and an 8% power cost escalation rate, the dollar-per-kilowatt evaluation factor would be calculated as follows:

$$i = \frac{1 + 0.15}{1 + 0.08} - 1 = 0.0648 \quad (9)$$

$$\$/\text{kW} = (1 - 0.40) \times \frac{1 + 0.0648^5 - 1}{0.0648 (1 + 0.0648)^5} \quad (10)$$

$$= \$1,093/\text{kW}$$

This equation is a useful way to include the time value of money, and is suitable for most economic evaluations of energy efficiency improvements. For very large projects it may be desirable to use an evaluation method which further refines the preceding equations to allow for such factors as depreciation, tax investment credits, and variable escalation rates.

3.7 COGENERATION AND ENERGY RECOVERY

Power costs can be reduced by investing in-plant generation. The generation normally is added in the form of cogeneration. *Cogeneration* means using the waste heat from a power generating cycle for process heating; or conversely, using waste heat from a plant process to generate power. The generation cycle thermal efficiency thus can be increased from about 25% (typical industrial generating efficiency) to about 70% when waste heat is recovered. Power generated in the cogenerating mode is normally less expensive than purchased power and results in direct savings to the plant. Typical utility generating units operate at 35% efficiency, so the higher efficiency of cogenerating can make it an attractive option.

One of two power cycles are used for cogenerating, depending on the plant processes used to absorb the waste heat. The Brayton cycle includes a gas turbine to generate power, and a waste heat boiler to generate steam from the hot 500°C to 600°C ($\approx 950^\circ\text{F}$ to 1100°F) exhaust gas. In some

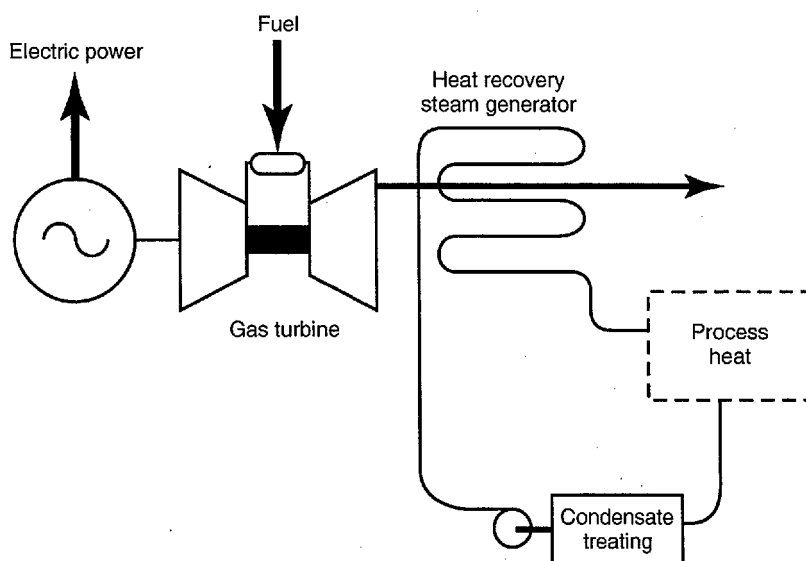


Figure 1—Brayton Cogeneration Cycle

instances, the exhaust flow can be sent into a process furnace to heat process feed. The recovery of the turbine exhaust heat reduces the amount of fuel normally required to provide an equal amount of thermal energy to the plant. The value of the saved fuel can be subtracted from the cost of the fuel to the gas turbine to arrive at the cost of power generated.

The Brayton (gas-turbine) cycle is considered a “topping” cycle because it consumes fuel and provides by-product heat to a consumer operating at a lower temperature. By contrast, a “bottoming” cycle consumes by-product heat from a higher temperature process and produces electric power.

The Carnot cycle uses a boiler and a steam turbine to recover thermal power, and can be configured as a topping cycle, or a bottoming cycle. When configured as topping cycle, the plant steam boilers generate steam at a higher pressure and temperature than is needed for heating plant processes. The

steam turbine is used to extract from the steam while reducing the pressure and temperature from boiler steam conditions to process conditions. The extra fuel cost for raising the steam pressure and temperature above process conditions is the fuel cost for generating the power developed by the turbine.

A typical bottoming cycle uses a steam turbine to extract power from steam being generated from process waste heat, or steam being let down from one plant steam pressure level to a lower level, or being sent to a condenser on the way to a cooling tower. The bottoming cycle finds use in plants where large amounts of waste heat are available from the cooling of exothermic processes. This cycle generates electricity from some of the heat which would otherwise be sent into the atmosphere at the cooling tower.

Hot exhaust from gas turbine generators is sometimes used directly in a process without using a heat recovery steam gen-

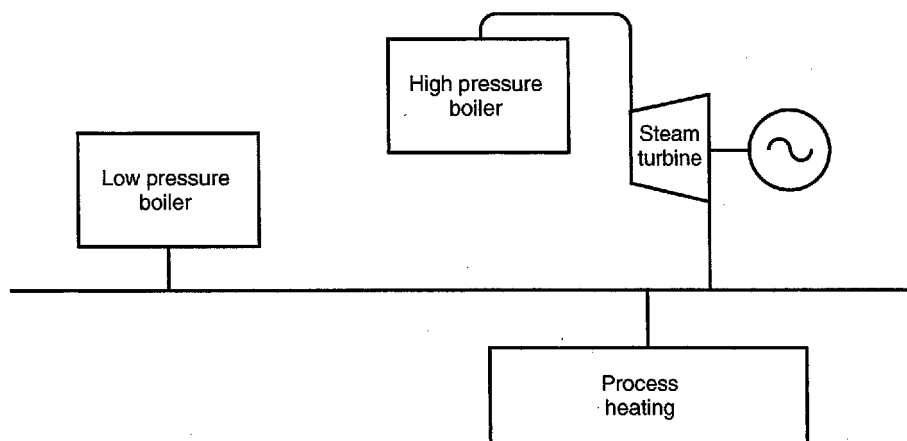


Figure 2—Carnot Topping Cycle

erator. Three examples of direct heating with turbine exhaust are: reducing the viscosity of products in transport pipelines; heating process feeds to process units; and supplying thermal energy for absorption refrigeration cycles.

Heating viscous products will lower viscosity and reduce the pumping energy required to transport the products through pipelines. Fired heaters are normally used for this. When gas turbines are sometimes used as generator drives to provide power for the transport pump motors, or are used to drive the pumps directly, the exhaust can be passed through an exchanger to heat the product, instead of using a fired heater. Using the waste heat from the gas turbine's exhaust will save the cost of the fuel used for a fired heater.

In process plants, gas turbine exhaust is used to heat feed stocks to processes, or to preheat combustion air for the process furnaces. This displaces much of the fuel that would otherwise be consumed.

The absorption refrigeration cycle uses a heat source to change the state of a refrigerant. The hot exhaust from a gas-turbine generator can be used with an absorption cycle to provide cooling. Absorption cycle equipment manufacturers can provide pre-engineered system elements to match the exhaust flow conditions of a number of gas turbines.

Sometimes there are opportunities to recover energy from process or utility streams. One method of energy recovery is the power recovery turbine, which is often used on catalytic cracking units to recover energy from the regenerator flue gases. The flue gases are directed through an expander which drives the unit's air blower, and an electric generator. The output of the generator is usually in the range of 5 megawatts to 10 megawatts (MW). Typically, an induction generator is used for this service.

A high-pressure fuel gas feed to a petroleum facility can also be used as a source of electric power by dropping the line pressure to plant utility pressure through an expander instead of a let-down valve. The expander is used to drive an induction generator adding power to the electric system. The majority of the gas flow goes through the expander, while a pressure control flow goes through a parallel control valve.

3.8 DESIGN CONSIDERATIONS

3.8.1 Transformers

Transformer efficiencies vary, depending on transformer characteristics. High-efficiency units can be purchased that provide efficiencies in excess of 99%. The importance of transformer efficiencies is that all power received from utilities (and much, if not all, received from in-plant generation) is transformed one or more times to reach utilization voltage levels; thus, the 1 or 2% losses occurring in transformers are applied to large blocks of power.

Transformer losses consist of no-load losses and load losses. No-load losses are losses resulting from energizing the primary winding at rated voltage with the secondary winding

open-circuited. These losses include eddy current losses, hysteresis losses, dielectric losses, and losses due to the resistance of the primary winding to excitation current. The eddy current and hysteresis losses are the most significant component of no-load losses. Because these losses occur in the core of the transformer, no-load losses are sometimes referred to as core losses or iron losses. For a given voltage, no-load losses can be considered to be constant.

Load losses vary with the flow of load current and include I^2R losses, eddy current losses, and stray load losses. The I^2R losses are the most significant and are caused by the flow of load current in both primary and secondary windings. Higher efficiency transformers usually have copper windings to minimize I^2R losses. Where forced cooling is specified, additional energy is consumed by fans or oil circulating pumps.

While transformers should be sized on the basis of maximum load, they should be designed for maximum efficiency at normal operating load, and efficiency should be evaluated accordingly. When specifying transformers, the load at which efficiency will be evaluated should be given.

3.8.2 Motors and Generators

Motor loads are the major consumers of energy in process plants. Typically, they can account for 70% of the electrical energy consumption. Motor efficiencies vary from 65% for the smallest HP motors, to 98% for the largest motors. High efficiency designs are available for motors in the standard frame size range. In the United States, the 1992 Energy Policy Act requires energy efficient motors for most motor categories.

Motor losses consist of the following:

- Stator I^2R loss.
- Rotor I^2R loss.
- Core loss (hysteresis and eddy current).
- Friction and windage.
- Stray-load loss.
- Excitation equipment losses (for synchronous machines).

Manufacturing design parameters that affect motor losses include:

- Quality and thickness of lamination steel.
- Size of the air gap.
- Stator and rotor resistances.
- Slot configurations.
- Number of poles (lower design speeds result in lower efficiencies).

Much effort is made to optimize these parameters because they also affect motor power factor, inrush current, and starting torque.

Operating conditions also affect motor efficiency. Typically, motor efficiency falls off rapidly as motor load is decreased below one-half of rated load. Operating a motor at

less than rated voltage will cause a decrease in efficiency due to higher stator losses and rotor losses. Operating at overvoltage decreases efficiency because higher magnetizing current and saturation cause increased stator and core losses. Operating with unbalanced voltages will increase losses (due to negative sequence torque) and result in higher winding temperatures. Motors connected to variable speed drives experience higher losses because of the harmonic content of the supply voltage and the load current. This is due to higher than normal hysteresis and eddy currents induced in the stator and rotor steel by the harmonic currents.

3.8.3 Lighting Equipment

Although lighting does not represent a major percentage of the electrical energy consumption of a petroleum facility, it nonetheless provides another area where energy savings can be achieved. The following guidelines can result in an energy efficient lighting system:

- a. Use the highest efficacy [lumens per watt (lm/W)] lamp that is capable of directing light to the task area involved.
- b. Select efficient ballasts (e.g., electronic ballasts for fluorescent fixtures).
- c. Maximize use of floodlights to illuminate general process areas.
- d. Use photocell or time controls to turn off outdoor lighting during daylight hours.
- e. Use manual controls for tower lighting with controls located at the tower base.
- f. Monitor lighting levels and reduce them where appropriate. For building lighting, this produces additional energy savings because of the reduced load on air conditioning equipment.
- g. Keep lamps and reflectors clean to obtain maximum light output.

3.8.4 Adjustable Speed Motor Control

Centrifugal pumps, fans, and compressors constitute a large percentage of the motor-driven loads in a petroleum facility. The torque requirements of these centrifugal loads vary as the square of the speed; thus, the brake horsepower required varies as the cube of the speed.

Traditionally, centrifugal loads have been designed to operate at constant speed with the process flow being controlled by some type of throttling means (pump control valves, fan dampers, or compressor inlet guide vanes). The energy losses from throttling can be substantial.

As an alternative to throttling, the speed of the centrifugal load can be controlled to obtain the desired flow rate without producing excessive pressure. Because the flow rate varies directly with speed while the horsepower requirement varies as the cube of the speed, using speed reduction to lower flow rates will result in a significant

horsepower reduction. For example, reducing the flow to one-half its initial value by lowering the speed of the load will cause the brake horsepower of the load to be reduced to one-eighth of its initial value.

A typical pump head-flow curve is depicted in Figure 3 to further illustrate the attractiveness of using speed adjustment to control flow rate. The darker-shaded area to the lower left of each operating point indicates the power required for that operating point. The lighter-shaded area indicates the power savings that result from using speed reduction rather than throttling to control flow rate. In general, a steep system curve, or a steep pump curve, will accentuate the potential power savings. Also, the lower the static head involved, the greater the power savings will be as a percentage of overall power consumption.

The conventional methods for achieving speed adjustment include hydraulic couplings, adjustable sheave belt systems, eddy current clutches, and wound-rotor motors. These devices are relatively inefficient, however, and usually require frequent maintenance. DC motors allow speed adjustment with improved efficiency but are also prone to requiring frequent maintenance and are difficult to apply in classified areas. Electronic adjustable-frequency controllers also provide speed adjustment and have been improved over the last decade. They are now the method of choice when adjustable speed drives are needed. The maintenance level for these controllers is the lowest of the alternative methods, however, these drives create voltage and current harmonics which may require remedial modifications to the power system and drive motor. Adjustable-frequency controllers have relatively high efficiencies and can be used with induction motors which require low maintenance and are readily available for classified areas. (See also Section 2.)

The capital cost of adjustable-speed drive equipment is higher than for constant speed equipment, so an economic evaluation as outlined in 3.6 is required to determine if the potential energy savings offsets the increased cost. A major factor in such an evaluation will be the duty cycle of the equipment involved; i.e., the percentage of time that equipment will function at operating points requiring less horsepower than the design point. If the equipment is expected to operate at close to its design point for a high percentage of time, then using an adjustable-speed drive system is probably not warranted. It is also important to remember that the application of adjustable-speed drives requires the consideration of other design factors, such as avoiding the operation of equipment at critical speeds and evaluating the effects of system harmonics that may be generated by adjustable frequency drive equipment. (See also 6.10.4.)

3.8.5 Conductor Sizing

Power cables are another source of energy loss in an electrical system. The magnitude of the energy loss depends on the

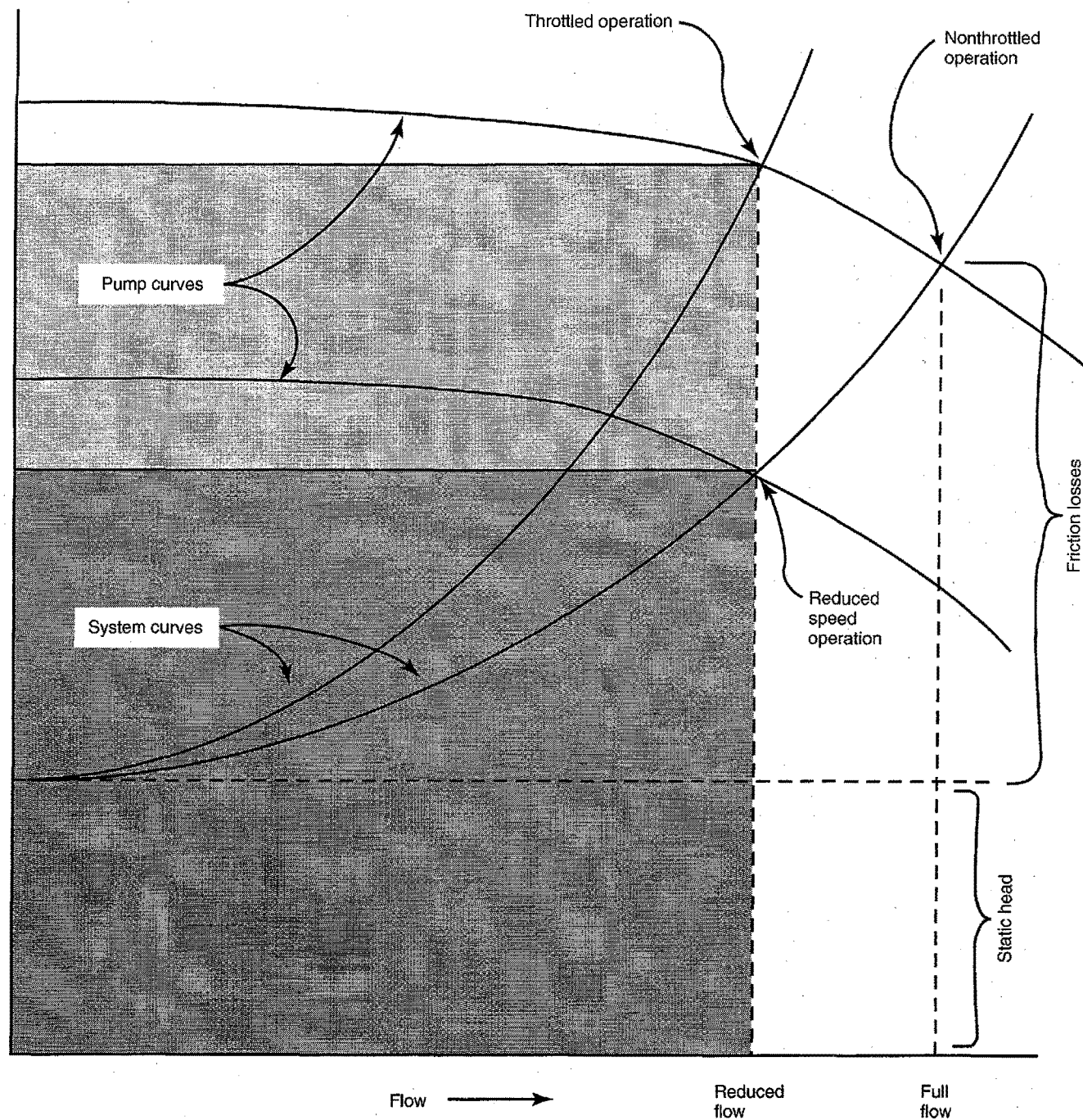


Figure 3—System Energy Losses: Adjustable Speed Versus Throttling

resistance of the cable as well as the amount of current expected to flow in the circuit. After power cables have been sized to meet the governing criteria (voltage drop, spare capacity, and the requirements of NFPA 70), a check should be made to determine if the anticipated energy loss in the cable would justify purchasing and installing the next larger size cable.

3.9 RELATIONSHIP TO POWER FACTOR

The apparent power consumed by an electrical system is expressed in kilovolt-amperes (kVA), and is composed of a kilowatt (kW) component and a kilovolt-ampere reactive (kvar) component. The kW component represents the real work extracted from the power system. The kvar component represents the magnetizing energy necessary for exciting electrical equipment such as motors and transformers, as well as the inductive and capacitive components of other devices on the system. Power factor is the ratio of kW to kVA and provides a measure of the percentage of kVA that is doing useful work.

The total current passing through the power system components (e.g., transformers, cables, transmission lines, switchgear) produces heating losses proportional to the square of the current (I^2R). The total current is proportional to the kVA, so by reducing kVA, losses can be reduced. To reduce kVA, it is only practical to cut exciting energy (kvar). In addition to wasting energy through transmission losses, excessive kvar loading uses up transformer, cable, and transmission line capacity, causing the supplying utility to overbuild their system. To control this, utilities pass on the excess cost through the use of power factor penalty clauses in power contracts. To avoid paying these penalties, power factor must be kept above a fixed value—normally between 0.90 and 0.94.

The large number of induction motors typical in a process plant can result in a low overall power factor on the system (0.85 power factor or less). Motors that are lightly loaded accentuate the problem because motor power factor decreases rapidly with decreasing load. The low power factor results in higher-than-necessary currents on the distribution system, resulting in higher losses. Improving the power factor will increase the overall efficiency of the power system. An improved power factor can also reduce or even eliminate power factor penalty charges if utility contracts contain such provisions.

The following actions can increase power factor, and reduce the associated losses:

- Using high power factor rated equipment, such as high power factor lighting ballasts.
- Using synchronous motors which can be operated at unity, or leading (capacitive) power factor.
- Operating high efficiency induction motors at close to design horsepower.

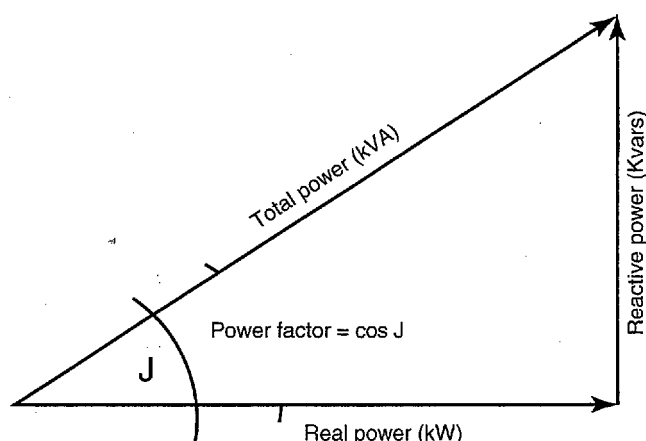


Figure 4—Power Relationship

- Using power factor correction capacitors to supply the reactive requirements of inductive loads.
- Increasing the excitation from in-plant generators.
- Installing a static var compensator.
- Controlling voltage so as to avoid overvoltage conditions.

When capacitors are applied to induction motors, the greatest benefit is obtained if the capacitors are installed at the motor terminals, and are switched on and off with the motor. Care must be taken in the application of power factor correction capacitors. Proper attention must be given to the effect that capacitors have on harmonic resonance, thermal overload sizing, circuit breaker switching capability, the lengthening of motor open-circuit time constants, and the possibility of motor self-excitation.

A synchronous condenser can also be used to improve power factor. This device is used mainly by utilities, however, and is not practical in most industrial plants.

3.10 DEFINITIONS AND CONVERSION FACTORS

The following is a list of definitions and conversion factors that are often useful in energy discussions:

- 1 British thermal unit (Btu) equals the heat required to raise the temperature of 1 pound of water by 1°F.
- 1 quad (quadrillion Btu) equals 1,015 Btu.
- 1 therm equals 100,000 Btu.
- 1 horsepower (Hp) equals 0.746 kW.
- 1 kWh equals 3,413 Btu.

Note: Due to thermal losses, approximately 10,000 Btu of raw fuel are consumed to produce 1 kWh of electricity in a conventional utility generating station.

- One 42-gallon barrel of fuel oil contains about 6 million Btu.
- One cubic foot of natural gas contains about 1,000 Btu.
- One ton of coal contains about 25 million Btu.

SECTION 4—FACILITY POWER SYSTEMS

4.1 PURPOSE

This section discusses the design considerations that must be evaluated for the development of a reliable and cost effective power system for continuously run petroleum facilities.

4.2 SCOPE

All aspects of facility power systems, from the point at which power is introduced into the facility to the points of utilization, are covered by this section. Topics include incoming lines for purchased power, in-plant generation, substations, transformers, switchgear, overhead distribution systems, voltage levels, system arrangements, protective relaying, fault currents, and system stability.

4.3 POWER SOURCES

4.3.1 Generated Power

Facility power stations not connected to public utility systems must be designed with redundancy to ensure a self-sufficiency for various operating contingencies. These power stations should have provisions for a cold (black) start and, as a minimum, should be designed to supply 100% of plant electrical loads after the loss of any single major component of the power generating system. Other contingencies, such as the capability of motor starting at reduced generation, should be considered.

4.3.1.1 Power Station Auxiliaries

Facility power stations that produce process steam and electricity must be provided with highly reliable station auxiliaries. The auxiliaries should be spared and supplied from a minimum of two independent sources devoted solely to providing auxiliaries. Critical auxiliaries for air, fuel, and water supplies should have steam-driven spares.

4.3.1.2 Power Station Bus Arrangements

The size and importance of the power station will determine the type of bus arrangement utilized for the main electrical connections. Small stations (less than 10 MW) frequently have only a single main bus as shown in Figure 5. Bus failures are not common, and fair reliability is obtained. It is necessary to shut down, however, when performing preventive maintenance to the main bus or when additions are made to the main bus. Circuit breakers must be taken out of service to be worked on, but this problem can be minimized by using drawout-type breakers. These disadvantages can result in disruption to essential station auxiliaries, such as draft fans, preheaters, boiler feed pumps, air compressors, and lighting.

Unit construction, illustrated in Figure 6, can be used in isolated power stations. With this construction, each generator has its own boiler or turbine, main bus, and boiler, or turbine auxiliary bus. Normally, the tie circuit breaker between the main buses is closed but will open in the event of a fault on either bus. In effect, the arrangement operates much the same as two independent power stations tied together. The main buses are tied together during normal operation, so each side must be rated for the total fault duty resulting from both generators.

A synchronizing bus scheme, shown in simplified form in Figure 7, is often used for a power station bus. This scheme offers a high degree of flexibility to add or remove generators and loads. The reactors serve to limit the amount of fault duty imposed on any one bus and to isolate voltage dips, to a degree, during faults. In this arrangement the loads on each bus are matched to the generating capacity on that bus to minimize the amount of load transfer through the synchronizing bus under normal operation.

The design of the power station bus arrangement should allow for future expansion, such as expanding a single or dual bus arrangement to a synchronizing bus arrangement. The design should also minimize the loss of generating capacity which would occur during a single fault or operating error.

4.3.1.3 Power Station Excitation Systems

The reliable generation of reactive power is a vital task performed by the generator field. The field is powered from an excitation system controlled by a voltage regulator system that maintains desired bus voltage conditions when operated in isolation. When operated in parallel with a utility, the voltage regulator system is biased to maintain a fixed reactive power or power factor. The two types of excitation systems in general use are brushless exciters, which are similar to those used on brushless synchronous motors; and static exciters, which feed power through slip rings to the generator field. With either system, means should be provided to ensure continued generator fault-current output for faults in close electrical proximity to the generator terminals, since these faults will severely depress the generator bus voltage. This will require the use of power current transformers for static excitation systems or a constant voltage source for the exciter field on a brushless system.

4.3.2 Purchased Power

When power is purchased from a utility, the following items, as a minimum, should be considered:

- a. Source and number of feeders.
- b. Reliability of utility system.
- c. Capacity and voltage of circuits.
- d. Power contracts and demand limitation.

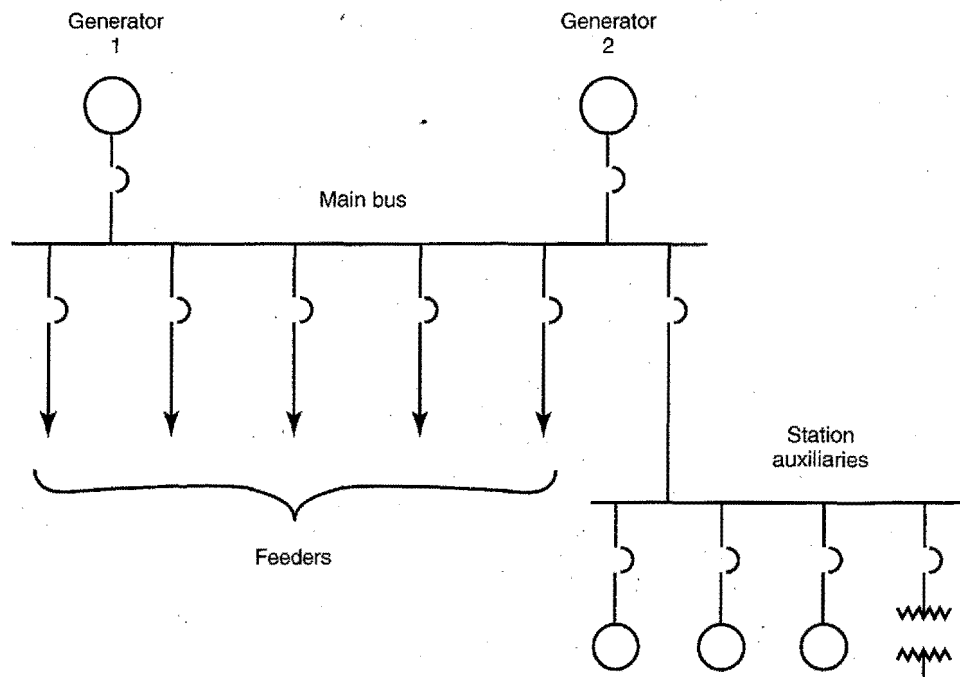


Figure 5—Single Main Bus Arrangement

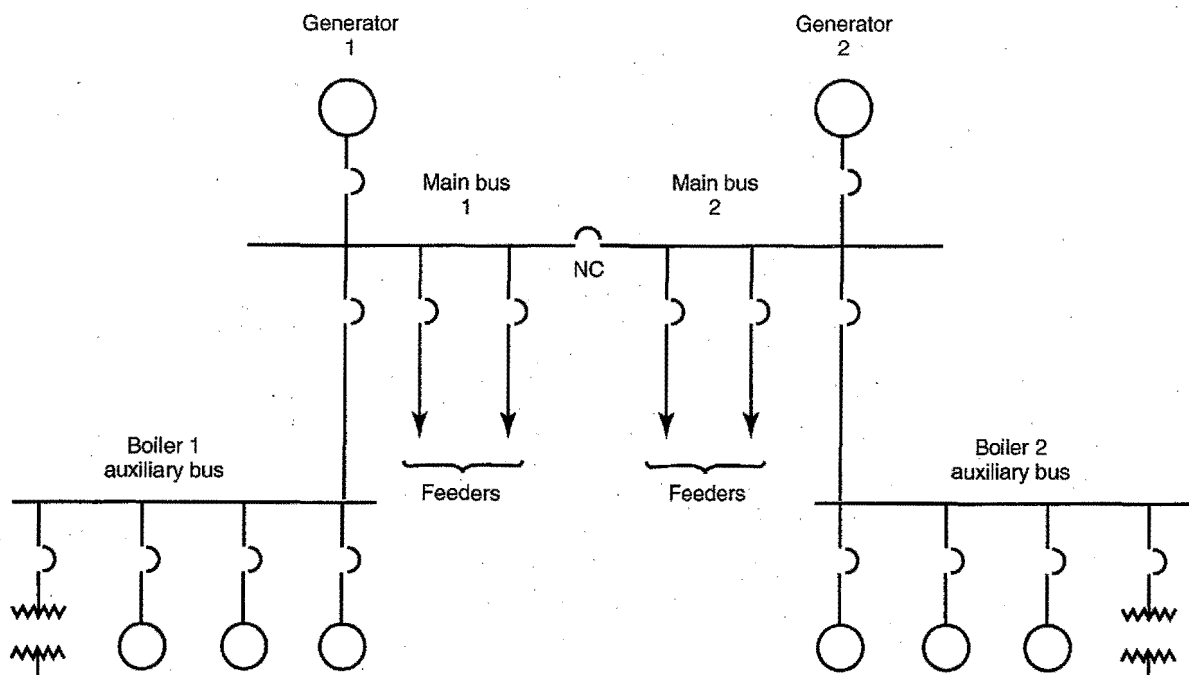


Figure 6—Unit Construction Bus Arrangement

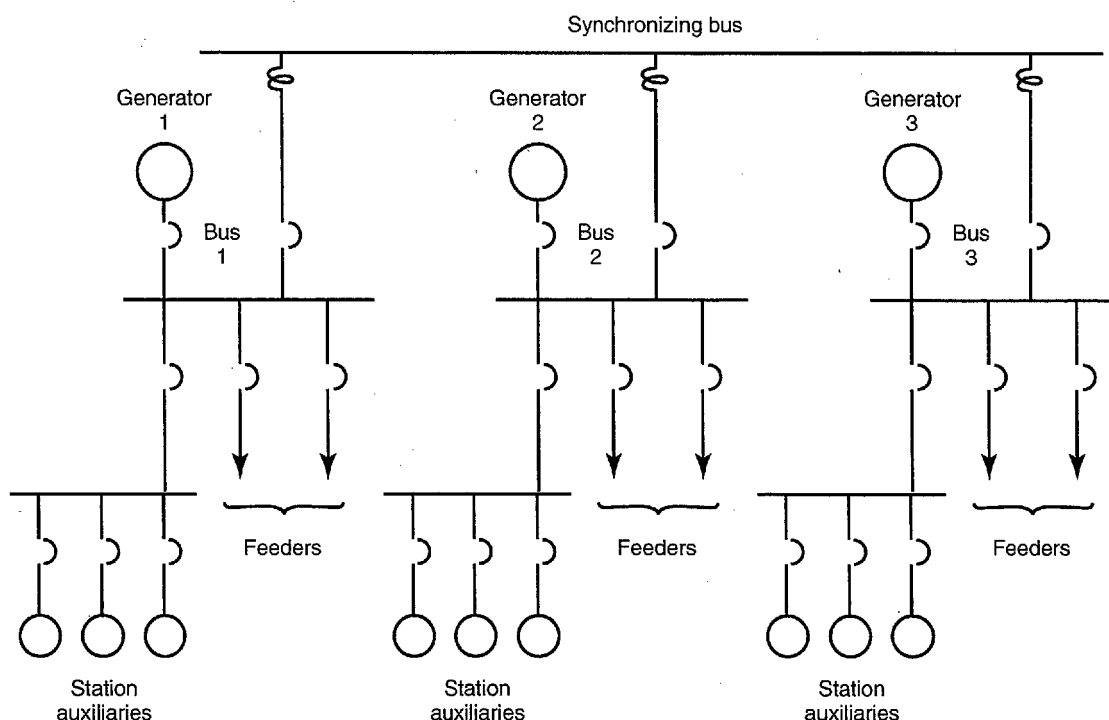


Figure 7—Synchronizing Bus Arrangement

- e. Parallel operation of multiple incoming lines.
- f. Automatic transfer scheme.
- g. Voltage regulation.
- h. Harmonic distortion, or harmonic current limitations.
- i. Short-circuit current.
- j. Coordination with utility relaying.
- k. Motor starting requirements.
- l. Reclosing procedures.
- m. Substation and metering requirements.
- n. System maintainability.
- o. Future potential additions or modifications to the petroleum facility.

4.3.2.1 Source and Number of Feeders

When major portions of the plant load are supplied by purchased power, multiple feeders should be provided to increase service reliability. Circuits should have maximum electrical isolation or redundancy. Where possible, circuits should be separately routed to minimize the possibility of total outage resulting from exposure to fire or to mechanical damage.

4.3.2.2 Reliability of Utility System

Utilities should provide information concerning routing, the type of construction, and the extent to which their circuits are protected against outage. Performance records of pertinent utility feeders should be examined to determine

the frequency and nature of service disturbances, the existence and speed of automatic reclosures, and the length of outages. Performance records should also be examined to determine if any actions have been taken to prevent recurrences of previous interruptions.

4.3.2.3 Capacity and Voltage of Circuits

Circuits should be sized so that if any one circuit is out of service, the remaining circuits have the capacity to carry the load continuously. Circuit voltage in most cases will depend on utility standards and the amount of purchased power required. When the voltage of incoming feeders is higher than the voltage selected for the facility, transformers of proper voltage rating will generally be included in each substation where utility feeders are terminated.

4.3.2.4 Power Contracts and Demand Limitations

The exact form of and terms set forth in power contracts will vary with the utility and region of the country. Energy charges include fuel adjustment costs as part of the contract. Demand charges are based both on kilowatts with power factor adjustments and on kilovolt-amperes. Power contracts may have maximum demand limitations or provisions under which demands beyond specified levels are supplied on an interruptible basis only. To determine the most favorable rate

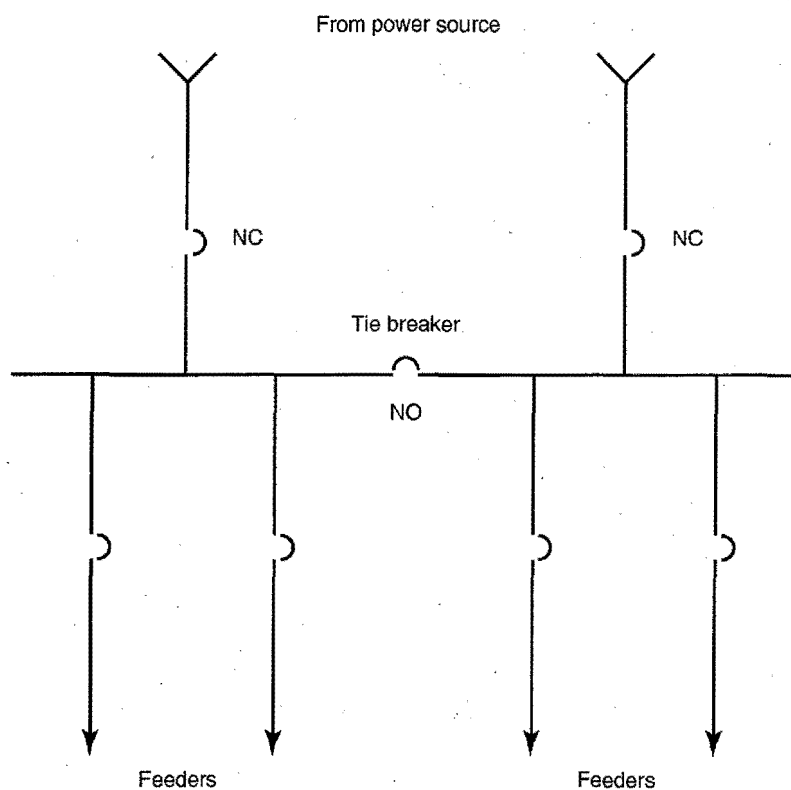


Figure 8—Purchased Power: Divided Feeder Operation

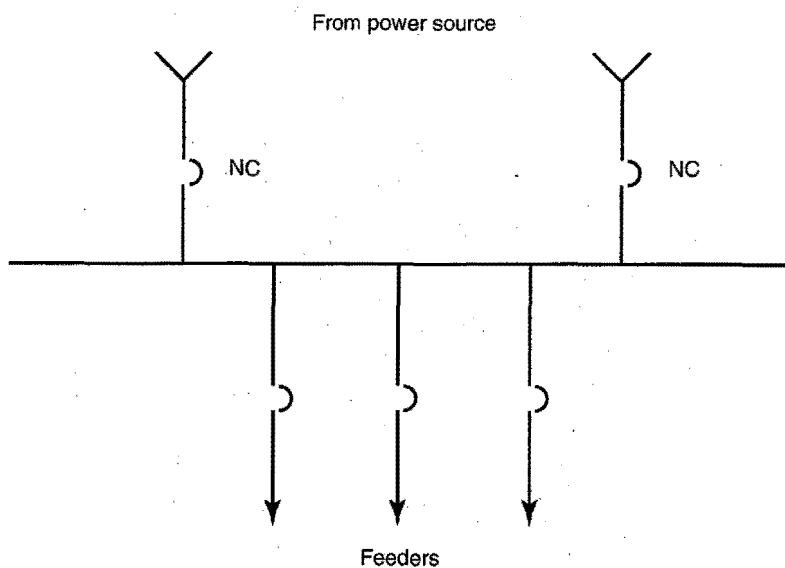


Figure 9—Purchased Power: Parallel Feeder Operation

it is essential to know firm demand and energy requirements as well as daily and seasonal load profiles.

4.3.2.5 Parallel Operation of Incoming Lines

The preferred operation of incoming utility lines is to parallel them on the substation bus. Typical arrangements are shown in Figures 8 and 9. Suitable relaying must be provided for proper system protection, and, before the feeders can be operated in parallel, protection must be provided (e.g., through the use of synchronization check relays) to verify that the voltages of the feeders are equal and synchronized.

4.3.2.6 Automatic Transfer Scheme

When incoming circuits cannot be paralleled, automatic transfer between the circuits should be considered. Load requirements should be checked carefully, and a regular testing method for the automatic transfer scheme should be included. Fast transfer schemes must consider the effects of residual voltage on motors and driven loads.

4.3.2.7 Voltage Regulation

Where utility or plant voltage varies (to unacceptable levels), automatic load-tap-changing transformers or other methods should be considered for maintaining close voltage regulation.

4.3.2.8 Harmonic Distortion, or Harmonic Current Limitations

Harmonic distortion, typically generated by nonsinusoidal waveforms originating from SCR rectifiers, adjustable speed drives, and similar electronic voltage and frequency controlled devices, can cause serious problems in electrical systems. Problems can include overloading and overheating of phase and neutral power systems; problems associated with high electrical noise on the system; inability of electronic hardware to synchronize; failure of frequency-sensitive circuits such as lighting ballasts; failure of adjustable speed drives and motor windings due to reflected waves; and many other abnormalities. IEEE Std 399 and Std 519 should be reviewed for systems with appreciable nonsinusoidal harmonics. Often, utilities will impose limitations on the maximum amount of harmonic current being generated by the customer into the utility supply.

4.3.2.9 Short-Circuit Current

The electrical system must be designed to accommodate the maximum short-circuit current that would result from the combined effect of both utility and in-plant sources. All system components, such as circuit breakers, transformers, and buses, must have ratings that can adequately withstand and interrupt the effects of the fault currents to which they are exposed. The minimum utility short-circuit level must also be

known so that its effect on motor starting and protective relay settings can be determined.

4.3.2.10 Coordination with Utility Relaying

Proper coordination between substation and utility protective relaying is essential to minimize the number and duration of power outages. The proper relaying should be selected by the user in collaboration with the utility company.

4.3.2.11 Motor Starting Requirements

The voltage drop which occurs on the plant bus during motor starting should be calculated to ensure that plant and utility company limitations are met. The voltage-drop calculation should be based on the starting of the plant's largest motor with all other required plant loads in operation. Reduced-voltage starting or an auxiliary starting driver may be required when the utility system is not stiff enough to allow full-voltage starting.

4.3.2.12 Reclosing Procedures

Utilities may employ automatic reclosing schemes on overhead lines because the faults which occur on overhead lines are often transient in nature. The delay time and number of automatic reclosures are based on a review of such factors as the voltage level of the feeder and the feeding of the plant from either a radial distribution feeder or a tap on a transmission tie line. The delay time before and between automatic reclosures and the number of reclosures are required for the design of protective relaying and system control schemes.

4.3.2.13 Substation and Metering Requirements

Characteristics of a facility substation, should take into consideration:

- a. Largest single load.
- b. Total connected load.
- c. Maximum allowable voltage drop.
- d. Utility reliability.
- e. Substation ownership (utility versus user).
- f. Primary versus secondary metering.
- g. Spare transformer capacity.
- h. Future load growth and expansion requirements.
- i. Grounding.
- j. Isoceraunic (lightning frequency) level and protection schemes.
- k. Facility life.
- l. Maintainability as it would affect substation design.

4.3.2.14 System Maintainability

The electrical distribution and utilization system must be designed so that it can be inspected and maintained on a regular basis to assure reliable operation. Other factors to be considered are:

electrical facilities for a petroleum facility are maintained at the same maintenance intervals as other process equipment. The connection of unrelated process equipment should be avoided if it cannot be shutdown during the primary facility shutdown.

4.3.2.15 Facility Additions or Modifications

Design of electrical systems should take into consideration any potential additions or modifications of the facility. This is especially important when selecting equipment fault duty ratings and designing provisions for future expansion or additions.

4.3.3 Parallel Operation with Purchased and Generated Power

When a utility supplies a part of the facility power requirements and operates in parallel with plant generated power, the following must be considered:

- a. Division and interchange of real and reactive power.
- b. Protective relaying.
- c. Service restoration procedures.

4.3.3.1 Division and Interchange of Real and Reactive Power

Power interchanges between utility and industrial systems can vary due to excess plant power generation, utility power restrictions, or load adjustments to maintain constant demand on the utility system. Contracts for the purchase of utility power should include the amount of kilowatts and kilovars and the division or interchange of them between the utility and the facility. If the utility line voltage is subject to wide variations, a method for controlling kilovar interchange as well as regulating voltage should be considered. Possible methods include automatic load-tap changers on transformers, power factor correction capacitors, and power factor control of the generator or synchronous motor excitation systems.

4.3.3.2 Protective Relaying

Protective relaying must be provided to protect the plant and its generation from faults or power loss in the utility system. The relaying must protect against adverse interactions between the systems and, if necessary for system stability, must act to isolate plant generation from the utility system. Impedance, reverse power, directional overcurrent, or underfrequency relays may be used to trip the incoming supply circuit breakers. If plant load exceeds generation, an automatic load-shedding system should be provided to relieve generation overloads after isolation and to maintain plant system stability.

4.3.3.3 Service Restoration Procedures

Various fault or switching conditions may cause facility and utility generating systems to separate. The usual sequence involves a fault transient disturbance affecting both systems until separation occurs, followed by recovery of the isolated systems. The fault transient may cause a voltage dip which will cause motors to drop off the line; however, if process conditions allow, important drives can have their control equipped to permit their restarting automatically when plant voltage recovers.

Operation of plant generation after separation may require automatically adjusting the load on plant generation to the load level that it can successfully restart automatically and supply continuously with acceptable voltage and frequency levels. If the plant has been receiving power from the public utility, voltage and frequency will fall unless load-shedding restores the proper balance or the plant turbine-generators can increase output to the proper level. If the plant had been sending power to the public utility before isolation, electrical output must be reduced. The effect of this reduction on plant steam system conditions must also be determined.

Paralleling of the plant generation and the utility system should be possible only at selected circuit breakers that are equipped with synchronizing switches connecting these breakers into the plant synchronizing system. Other circuit breakers where inadvertent paralleling is possible should be equipped with synchronizing-check relays that prevent closing unless voltage and frequency conditions at both terminals of the breakers are within prescribed limits. Relays which protect the system during fault conditions must be applied and set carefully to prevent separation from occurring during synchronizing swings.

A power system study is normally required to provide the proper protective relaying and settings as well as the generating system and load shedding system parameters necessary for system stability during the fault and recovery transients.

4.4 SYSTEM VOLTAGES

4.4.1 Selection

The selection of system voltages in a facility is based primarily on economics, with consideration given to the following factors:

- a. Class of service available from the utility.
- b. Total connected load.
- c. Planning for future growth.
- d. Plant standardization of equipment.
- e. Density and distribution of the load.
- f. Safety.
- g. Interconnection to existing systems.
- h. Equipment availability.
- i. Practical conductor and equipment size.

4.4.2 Voltage Levels

The voltage levels in a facility can be divided as follows:

- a. Less than or equal to 600 V (low).
- b. From 601 V to 69,000 V (medium).
- c. Greater than 69,000 V (high).

The low-voltage level is normally used to supply small motors, lighting, and controls. The medium-voltage level is normally used for larger motors and for distribution of small and medium blocks of power. Voltage levels of 34,500 V to 69,000 V may be used for large blocks of power. The high-voltage level is used for the transmission and distribution of bulk power.

4.5 POWER SYSTEM ARRANGEMENTS

Four basic types of power system arrangements are available: the radial, the primary-selective radial, the secondary-selective radial, and the secondary-selective parallel. The selection of a system arrangement is governed by factors such as service continuity, flexibility, regulation, efficiency, operating costs, investment costs, and reliability of the power source. Maintainability of equipment should be carefully considered because it affects all of these factors. Systems that utilize multiple supplies, loops, and ties can be quite complex. The number of relays, switches, and interlocks required by these systems necessitates careful engineering to avoid shutdowns resulting from equipment failures or improper operation.

4.5.1 Simple Radial System

The easiest system to understand, operate, and troubleshoot is the simple radial system shown in Figure 10. It is the least expensive system to install and is expandable. The disadvantage of the simple radial system is that it provides no alternate source of power. A failure in the primary breaker, cable, switch, or transformer can result in a process shutdown. Placing a single load group or process unit on a radial feeder will reduce the effects of a circuit failure on the overall facility.

4.5.2 Primary-Selective Radial System

The primary-selective radial system shown in Figure 11 provides better service continuity and more flexibility than the simple radial system because only half the transformers are on one feeder. Should a feeder fail, the affected loads can be switched to the other feeder. Voltage regulation in a primary-selective radial system is comparable to that of a simple radial system; however, the initial investment in a primary-selective radial system is higher.

4.5.3 Secondary-Selective Radial System

The secondary-selective radial system, shown in Figure 12, provides service continuity and voltage regulation. A feeder

fault will cause half the load to be dropped, but service can be restored quickly through manual or automatic operation of the secondary tie breakers. Investment costs of this system are relatively high.

4.5.4 Secondary-Selective Parallel System

The secondary-selective parallel system, shown in Figure 13, provides uninterrupted service continuity and voltage regulation to all loads. The unit substation tie breaker is normally closed and an interruption of either of the source supplies will not interrupt any of the loads. This configuration is by far the most complex and costly, but may be justified based on consequences associated with process disruption. A consideration is that disturbances on one bus may affect loads connected to the other bus. Equipment fault ratings must be sized for the total fault duty from all sources.

4.6 POWER SYSTEM STUDIES

4.6.1 General

The planning, design and operation of a power system requires continual and comprehensive analyses to evaluate current system performance and to establish the effectiveness of alternative plans for system expansion.

4.6.2 System Studies

Studies that will assist in the evaluation of initial and future system performance, reliability, safety and ability to grow with production and/or operating changes are:

- a. Load flow.
- b. Cable ampacity.
- c. Short-circuit.
- d. Protective Device Coordination.
- e. Stability.
- f. Motor starting.
- g. Insulation Coordination.
- h. Reliability.
- i. Grounding.
- j. Harmonics.

The procedures for performing the above system studies are outlined in many publications devoted to the subject. Included among these are the following:

- a. IEEE Std 80.
- b. IEEE 141 (Red Book).
- c. IEEE Std 242 (Buff Book).
- d. IEEE Std 399 (Brown Book).
- e. IEEE Std 493 (Gold Book).
- f. IEEE Std 519.



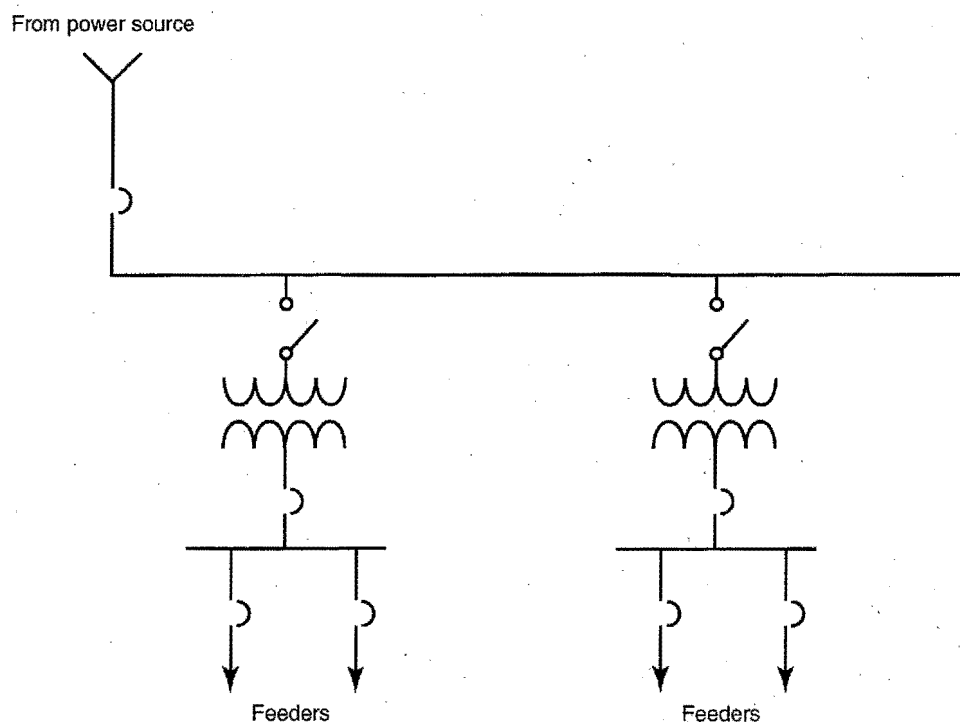


Figure 10—Simple Radial System

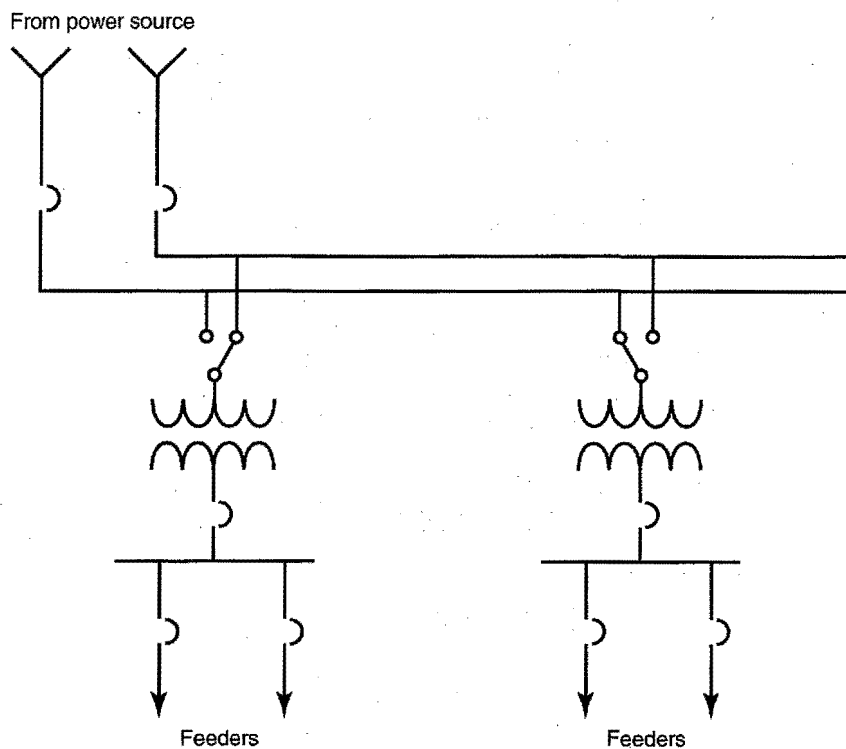
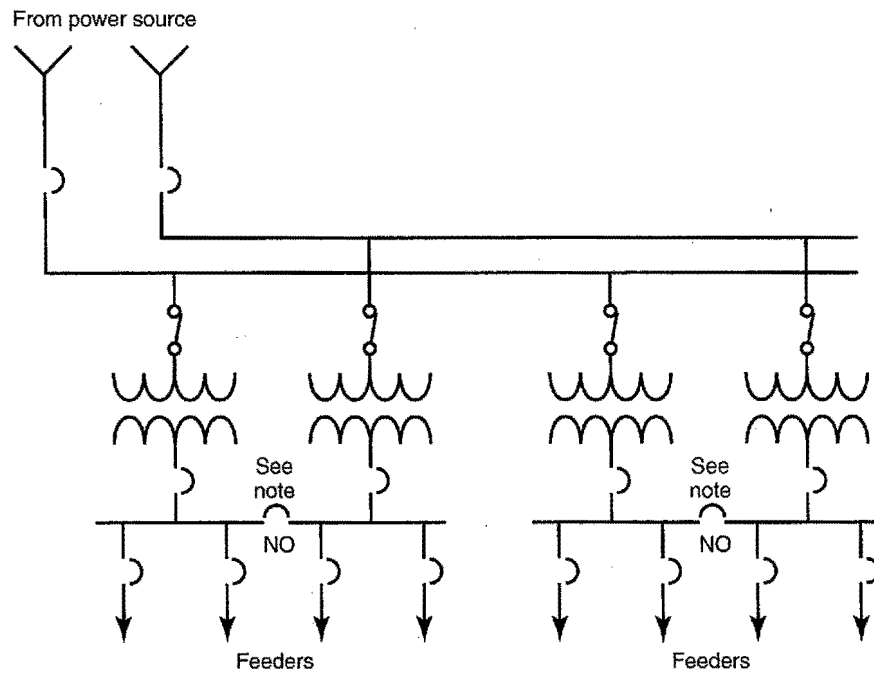


Figure 11—Primary-Selective Radial System



Note: For automatic mode of operation, tie breaker is interlocked to prevent closing unless one transformer breaker is open.

Figure 12—Secondary-Selective Radial System

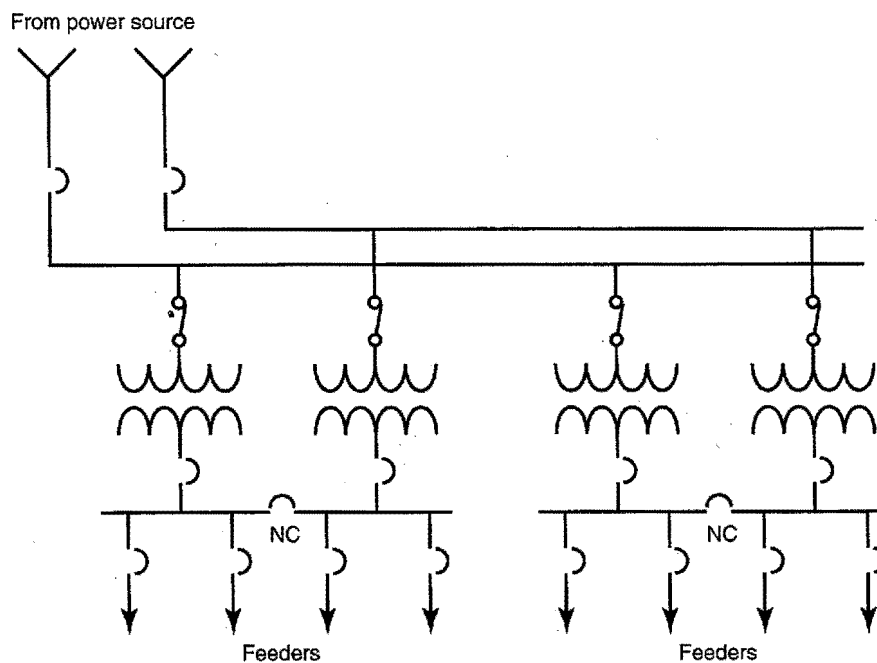


Figure 13—Secondary-Selective Parallel System