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Revision Memo

- 12/00** This is an update of Section XXX-B. The changes are covered below by subsection.
- REFERENCES - Added internet addresses for the referenced documents.
- DEFINITION - In Reserve Ratio - Added Firm capacity definition.
- EQUIPMENT TYPES AND APPLICATIONS - In Turbine Generators subsection- replaced "boot strap operation" with "black start capability". In Generator Excitation and Voltage Regulation subsection - Added Max/Min excitation limiters requirements. In Neutral Grounding Devices subsection - Added Voltage rating of a grounding transformer. In Generator Terminal Equipment subsection - Added Rogowski Coils. In Synchronizing Equipment subsection - Added Using a specific Circuit Breaker. In Feeder and Control Circuits - Clarified cabling method and referenced IP16-6-1, P14.1.
- SYSTEM DESIGN CONSIDERATIONS - In One-Line Diagram subsection - Added Transformer impedance. In System Generating Capacity - Clarified reserve ratio requirements. In Main Bus Arrangements subsection - Alternative generator connection to systems is proposed. In Steady-State Stability subsection - Revised the requirements. In Loss -of-Stability subsection - Additional requirements for Min excitation limiter and Field undervoltage relay are specified. In Load Shedding subsection - Proposed PLC based scheme to frequency based schemes.
- COMPONENT DESIGN PROCEDURES - In Turbine Generator subsection - The requirement of 200% current for 30 seconds is clarified. In the relay subsections - Added 81 and 60 relays and descriptions. Figures 5, 13, 14, 15, 16 and 17 were checked / corrected and updated.



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SCOPE

This section presents the fundamental design considerations for electric power generation systems. With few exceptions, power generation utilizes either steam turbine generators or gas turbine generators and this section is restricted to these types. Two exceptions are diesel engine generators and flue-gas expander generators.

The most commonly used generation voltages for industrial plants are in the 6 - 15 kV range. Generation voltage in the 3 to 5 kV and 400 to 480 volt range are sometimes used for plants with small total installed capacities, for example, 10,000 kVA and below. This section is generally applicable to plants in the 6 - 15 kV range and above 10,000 kVA installed capacity. It may be used with modification for plants operating at lower voltages or with lower capacity.

REFERENCES

DESIGN PRACTICES

Section I	Design Economics
Section XV	Safety in Plant Design
Section XXVI	Steam Facilities

INTERNATIONAL PRACTICES

IP 10-7-2	Special Purpose Steam Turbines for Generator Drivers
IP 10-8-1	Combustion Gas Turbines
IP 16-2-1	Power System Design
IP 16-4-1	Grounding and Overvoltage Protection
IP 16-8-1	Instrument Power Supply
IP 16-9-3	Synchronous Generators
IP 16-11-1	Neutral Grounding Resistors
IP 16-12-1	Switchgear, Control Centers and Bus Duct
IP 16-12-2	Control of Secondary-Selective Substations with Automatic Transfer

OTHER REFERENCES

Recommended Practice for Grounding of Industrial and Commercial Power Systems, ANSI / IEEE (Institute of Electrical and Electronics Engineers) Standard 142-1991, (IEEE Green Book)

Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems, ANSI / IEEE Standard 242-1986, (IEEE Buff Book)

IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part 2, Grounding of Synchronous Generator Systems, IEEE Standard C62.92, 1989. (Note: IEEE Standards can be ordered online from www.ieee.org)

Dunki-Jacobs, J. R., *Transient Stability Criteria of Industrial Power Systems – A Quantitative Analysis*, IEEE Conference Paper 60-1176. (Reprints available through askieeee@ieee.org)

Computer Representation of Excitation Systems, IEEE Transactions Paper 31 TP67-424, IEEE Committee Report

Fountain, L. L. and Blackburn, J. L., *Application and Testing of Frequency Relays for Load Shedding*, IEEE (formerly AIEE) Transactions Paper 54-372. (Reprints available through askieeee@ieee.org)

Lokay, H. E. and Bortnyk, V., *Application of Under-Frequency Relays for Automatic Load Shedding*, IEEE Transactions Paper 31 TP67-447. (Paper copy available online at www.geindustrial.com/edc/pm/notes/get6449.pdf)

BACKGROUND

The electric power generation system is part of the overall plant utility system and provides electric power to onsite and offsite areas as well as to utilization equipment in the power plant itself.

The power generators may be the only source of plant electric power or may operate in conjunction with a public utility supply. In the latter case, the in-plant generation may be operated in synchronism with the public utility supply or separated from the public utility supply. In some locations, power in excess of plant requirements is exchanged or sold to the public utility system in accordance with power contract terms.

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DEFINITIONS

(Refer to [Section XXX-A](#) and the following.)

Base Load

Setting the output capacity of a turbine generator at a fixed value for long periods of time.

Charging Current

The capacitive current which flows as a result of the inherent phase to ground capacitance of electrical system components such as insulated cables, insulated rotating machine windings, surge capacitors and overhead lines.

Circuit Breaker Position Semaphore

A control board device which is part of a mimic bus and which combines control switch, position indication and status disagreement functions. A typical semaphore permits the operator to open and close the circuit breaker, indicates breaker open or closed by horizontal or vertical position, and flashes when the breaker is tripped or closed.

Rectifier

A device used to convert alternating current (a-c) to direct current (d-c).

▶ Reserve Ratio

Ratio of the installed capacity to the firm capacity of electric power sources. (Firm Capacity means steady state capacity with largest source out of service).

Stub Bus

A bus connected to a synchronizing bus and having one or more generators or a purchased power source. Stub busses are used to supply plant loads and are sometimes called "machine busses".

Synchronizing Bus

A bus used to transfer power between stub busses or between plants in the case of separate power plants. Used with reactors, in stub bus-synchronizing bus circuits, the synchronizing bus-stub bus arrangement is an effective means of limiting the increase in system short circuit levels when generation capacity is added to an existing system.

Turbine Generator Capability

The capability of the turbine generator to produce real power (kilowatts or megawatts) and reactive power (kilovars or megavars). Real power capability is determined by the rating of the steam turbine or gas turbine driver; reactive power capability by the generator volt-ampere (kVA or MVA) rating and the capability of the generator excitation system.

Unit Concept for Boiler and Turbine Generator

The arrangement in which a boiler is connected to one turbine generator only. Boiler and turbine generator auxiliaries are also sized and arranged to supply these single units only.

EQUIPMENT TYPES AND APPLICATIONS

TURBINE GENERATORS - GENERAL

The electric power generating units most commonly used in ExxonMobil plants are driven either by steam turbines or combustion gas-turbines.

Generators are usually two-pole, of non-salient pole construction (3600 rpm 60 Hz or 3000 rpm 50 Hz), with closed circuit cooling systems. Steam turbine driven units manufactured in the U.S.A. are direct driven without speed reduction gears; units manufactured elsewhere may be direct driven or driven through reduction gears. Gas turbine driven units may be direct driven or driven through reduction gears. Typical generator voltages are 4.16 and 13.2 kV in the Americas; 5 or 6, 10 or 11, and 15 kV in Europe and locations following European practice.

Generator excitation systems may be the brushless type having a rotating a-c exciter and rotating rectifier; the static type employing a stationary rectifier assembly and no-rotating parts except the generator rotor slip rings; or a combination type using a rotating a-c exciter, a stationary static rectifier, and generator rotor slip rings.

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EQUIPMENT TYPES AND APPLICATIONS (Cont)

Gas turbines for refinery and petrochemical plant turbine generator service are usually the heavy duty industrial type. In other applications, such as pipeline service, aircraft type gas turbines are sometimes used.

- Gas-turbine generator units can be supplied as self-contained packaged units with an enclosure for the generating equipment, excitation equipment, control and protective relaying equipment. These units require only fuel, water, and the main electrical system connections. Package units can also be equipped with Black-Start capability in which the unit automatically restores power to the electrical system after a total utilities loss.

Each turbine generator will have specific real power (kilowatt or megawatt) and reactive power (kilovar or megavar) capability. Real power capability limit is a function of turbine capability. Reactive power capability is a function of generator and excitation system capability.

Figure 1 is a typical generator capability curve showing the real power-reactive power-power factor relationship.

STEAM TURBINE GENERATORS

Steam turbine generators can be classified according to turbine type:

- Condensing
- Extraction Condensing
- Non-condensing
- Extraction Non-condensing

The condensing unit is the most flexible for power generation purposes. It can generate power over the range from no-load steam flow (approximately 10% of rated flow) up to the rated flow capability of the turbine. All throttle flow is exhausted at a pressure below atmospheric into a steam condenser and passes back to the boiler deaerator for use as boiler feed water. Therefore, the condensing turbine generator is not affected by process steam load variations and can generate power as required by the electrical load. However, because of the large amount of heat remaining in the steam entering the condenser, which must be rejected to the cooling water, straight condensing operation is held to the practical minimum. A typical industrial plant condensing cycle may have a cycle efficiency of 25%. In contrast, a public utility power plant condensing cycle can have an efficiency of 39%. Therefore, when purchased power is available, power generated in industrial condensing generation has to compete with power generated in the usually much higher efficiency public utility cycle.

The non-condensing unit (also known as a "back-pressure" unit) exhausts steam at an exhaust pressure level above atmospheric pressure. These units are usually controlled by a controller which responds to exhaust pressure level changes. Power generation is a function of a steam demand at the exhaust pressure level and can not be adjusted independently.

Extraction units have one or more outlets at intermediate pressure levels between inlet and exhaust pressure levels. Extraction units may be condensing or non-condensing. The extraction is usually controlled (automatic) responding to steam load variations at the extraction pressure level but may be uncontrolled when this type meets the system design basis. In the uncontrolled type, flow from the extraction outlet is dictated by the turbine design alone and system pressure at the extraction level must be controlled by other equipment. Power generation capability for the extraction type is basically a function of the steam load requirement at the extraction pressure level. However, the extraction condensing unit can accept electrical load variations without regard to process steam requirements within the kilowatt limits imposed by the proportion of the inlet steam flow that can be sent to the steam condenser. Typical capability curves for extraction units are shown in **Figures 2 and 3**.

Power generation capability of non-condensing, extraction-condensing, and extraction non-condensing units is affected by seasonal variations in process steam loads. This variation can be substantial and its effect on power generation capability must be determined for each application.

Non-condensing and extraction units improve cycle efficiency over condensing cycle values since all or part of the steam flow to the turbine inlet does not pass to a condenser and is utilized after leaving the turbine. The amount of improvement depends on the specific plant design.

COMBUSTION GAS TURBINE GENERATORS

These units compress air for combustion in the gas turbine compression stage, burn the compressed air-fuel mixture in combustion chambers and expand the hot combustion gases in the power turbine stages to drive the generator (and the compression stage). The hot exhaust gas is passed to an exhaust stack or into waste heat utilization equipment such as a heat recovery steam generator (HRSG).

The gas turbine generator has the capability of generating power over its entire range as dictated by electrical load. For units typically used in ExxonMobil plants, gas turbine heat rates for operation without utilization of the heat contained in the exhaust gases are in the 12,000 - 14,000 Btu per kilowatt-hour range. The cycle efficiency is in the 27 to 24% range.

Economic design and operation dictate that, when possible, the exhaust heat be utilized and that the gas turbine be operated as close to rating as possible. Waste heat utilization can improve cycle efficiency into the 50 to 75% range. On the other hand, operation at 50% of rated gas turbine capability can increase the heat rate approximately 30% and decreases the heat content of the exhaust gas approximately 25%.

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EQUIPMENT TYPES AND APPLICATIONS (Cont)

Gas turbine capability varies inversely with ambient air temperature. Nameplate rating is normally at International Standards Organization (ISO) conditions, 15°C (59°F) and 1 bar (14.696 psia) ambient conditions. Formerly, 80°F was widely used as the nameplate-rating ambient temperature. For each application, the standard conditions rating must be adjusted to reflect the site maximum ambient temperature and elevation.

Figure 4 is a typical gas turbine performance curve showing inlet air temperature - exhaust temperature - fuel consumption - output relationships (based on 80°F).

GENERATOR COOLING

Two-pole generators require closed circuit cooling systems, with air or hydrogen as the cooling medium which is passed over the generator windings. In the United States, vendor practice is to use air as the cooling medium for smaller generators, and hydrogen for larger generators. The size at which hydrogen cooling is used varies among vendors, but is typically above the 75 MVA (megavolt ampere) generator size. Air-water and hydrogen-water heat exchangers are normally used although air-fin exchangers may be used for specific cases where economics or ambient conditions dictate. Water-cooled exchangers are located on the top of the generator or included as part of the generator enclosure. Some gas turbine generator units supplied with slow speed (600 - 720 rpm) generators use once-through air cooling systems.

Closed circuit cooling systems should provide at least two independent cooling sections to permit removal of one section while the turbine generator is in service at reduced capacity, usually 67% minimum.

GENERATOR EXCITATION AND VOLTAGE REGULATION

The excitation system is comprised of the generator field (rotor winding) and the equipment required to supply d-c to the field. Voltage is generated by the action of the magnetic field established by the generator rotor winding on the conductors of the generator stator winding.

The basic types of modern excitation systems are the static and the brushless rotating type. Equipment arrangements vary so manufacturer's information should be consulted. Examples of the types are shown in **Figures 5 and 6**.

The static type takes a voltage supply and a current supply from the generator leads to external rectification equipment which returns d-c to the generator field via the rotor slip ring and brush harness.

The brushless type has a separate a-c generator mounted on the main generator shaft which supplies a-c to a rotating rectifier assembly also mounted on the shaft which supplies d-c to the field.

One variation uses a shaft-mounted a-c generator, external rectifying equipment and rotor slip-rings and brush harness.

The excitation system is controlled by the generator voltage regulator. In the automatic mode, the voltage regulator receives a voltage sensing input and a reactive current compensation input from potential and current transformers, respectively connected to the generator terminal leads. The regulator converts the current to a modifying voltage which adds to or subtracts from the input voltage. The resultant voltage is compared to the regulator setting value and the regulator adjusts the excitation system to restore the generator voltage to the level equivalent to the regulator setting. The regulator may also be operated manually.

The reactive current compensation feature is required to permit generators to operate in synchronism (in parallel) and to control the sharing of reactive load requirements.

Power factor regulators are sometimes used in conjunction with the voltage regulator when generators operate in parallel with a public utility system and close power factor or var (kvar) control is needed. These regulators exert vernier-like action on the generator voltage, operating relatively slowly to compensate for small voltage changes. They are switched out automatically and the voltage regulator takes over when large changes occur requiring fast regulator action.

- ◆ Excitation systems may also be provided, if required, with other control accessories such as maximum excitation limiters, line drop compensators, power system stabilizers, etc. Maximum/Minimum excitation limiters are required when two or more generators are operating in parallel, especially if the utility tie connection is weak or island operation is contemplated.

NEUTRAL GROUNDING DEVICES

The most common method of neutral grounding for medium voltage systems is low resistance grounding. A grounding resistor is used to limit the ground fault current to the lowest value which is compatible with the protective relaying. Values normally found in ExxonMobil plants range from 400 amperes to 1600 amperes, although one multiple source system had a 4500 ampere level at one time.

The resistor ohmic value and current capacity is set by the ground fault current level selected. For instance, a 400 ampere resistor on a 13.8 kV system has a resistance of about 20 ohms. The resistors are usually not provided with taps. Their thermal rating is a short time rating such as 10 seconds since all ground faults are tripped.

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EQUIPMENT TYPES AND APPLICATIONS (Cont)

- ▶ The neutral grounding device used for a high resistance grounded system usually consists of a single phase distribution or similar type transformer with a loading resistor on the secondary winding. This provides the effect of the high resistance in the neutral circuit required for this type system. Since faults are not tripped automatically but activate alarms only, fault currents must be as low as possible. However, the fault current level must equal or exceed system charging current, or destructive overvoltages can occur. The voltage rating of a grounding transformer should not be less than the Line-to-Line voltage.

On medium voltage systems, fault current levels in the order of 5 amperes are typical for high-resistance-type grounding. All equipment must be fully rated since faults are not tripped automatically.

High resistance grounding packages are sometimes available which provide not only the grounding device, but also a control package which can provide a pulse current for fault location purposes. Ground detection either via protective relays or ground detection ammeters are normally provided.

GENERATOR TERMINAL EQUIPMENT

Normal practice is to provide space in the generator phase and neutral lead terminal compartment or enclosure for current and potential transformers associated with generator control and protection and for surge equipment. The phase and neutral leads may be in common or separate compartments or enclosures depending on manufacturer's design.

- ▶ A typical arrangement is:
 - Phase lead compartment.
 - + Partial discharge measuring system (such as Rogowski coils)
 - + Surge protection arresters and capacitors.
 - + Current transformer for the voltage regulator.
 - + Current transformers for generator differential relays (when generator feeder is not included in the differential zone).
 - + Potential transformers for voltage regulator, voltage restraint overcurrent, negative sequence, overvoltage, reverse power and loss of excitation protective functions.
 - Neutral lead compartment.
 - + Current transformers for voltage restraint overcurrent relay, negative sequence relay, reverse power relay and loss of excitation relay.
 - + Current transformers for generator differential relay.

SURGE PROTECTION EQUIPMENT

Normal practice provides surge protection equipment consisting of lightning arresters and capacitors for each generator. This equipment is provided to protect against any possibility that the generator stator winding will be exposed to lightning or switching surges. While the initial facilities may make such exposure unlikely, the surge protection package involves small additional cost and is best installed with the initial application

Surge protection may also be required at other points in the system in line with normal distribution system practice for transformers or busses which are exposed to overhead open-wire circuits either directly or indirectly through cable connections.

GENERATOR CONTROL AND METERING FACILITIES

Normal practice is to provide all the generator control and practically all of the metering facilities in the power plant central control room or the utilities console of the refinery central control room. Metering at the local panel is limited to excitation voltage and current. In some cases, even these meters have been omitted.

The turbine will require a local panel fully equipped to permit local start-up and run-up of the unit to rated speed. However, when the unit is at or close to rated speed, control is shifted to the control room for synchronizing to the system.

SYNCHRONIZING EQUIPMENT

- ▶ Turbine generators are synchronized to the electrical system using a specific circuit breaker (or one of available breakers). The function of the synchronizing equipment is provided to insure that, at the closing of the circuit breaker, the voltage difference, the frequency difference (slip frequency) and the phase angle difference between the incoming unit and the system voltage are within acceptable limits. Synchronizing equipment may be for either manual or automatic operation.

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EQUIPMENT TYPES AND APPLICATIONS (Cont)

Equipment for manual operation includes a synchroscope whose rotating pointer measures frequency difference and phase angle difference, incoming unit and running unit voltmeters and frequency meters, and indicating lights connected across the open breaker through PT's. The system operator carries out the synchronizing operation with the following controls:

1. The turbine governor motor control switch which varies the turbine speed. This changes the frequency of the generator output voltage and controls the frequency difference and phase angle difference between the generator voltage and the electrical system voltage.
2. The voltage regulator set point control which, in turn, changes the magnitude of the generator output voltage.
3. The control switch for the circuit breaker across which the synchronizing takes place (usually the circuit breaker connected to the generator terminals but other breakers can be used). When the synchroscope and the voltmeter indicate the voltages are in synchronism, the operator uses the control switch to close the circuit breaker.

Automatic synchronizing provisions include the manual equipment plus automatic equipment to carry out the frequency and voltage control functions and circuit breaker closing. In some cases, the circuit breaker closing action is left to the operator. An intermediate synchronizing arrangement combines the manual control features with frequency, voltage and phase angle measurement equipment which operates to prevent the circuit breaker closing if these conditions are not within acceptable limits.

Automatic synchronizing equipment must also permit closing the open circuit breaker into a de-energized bus.

TURBINE GENERATOR AUXILIARIES

The auxiliaries are those equipment components and utilities supplies required for start-up and shutdown and for normal operation. They vary according to the type of turbine generator. Therefore, specific requirements should be established for each design using data which is representative of the generating equipment which will be used. Following are typical examples:

Steam Turbine Generators:

- Lube oil and control oil or fluid systems including reservoirs, coolers and pumps.
- Gland sealing steam condenser.
- Turning gear and motor.
- Cooling water system for lube oil and generator air coolers.
- A-C and D-C supplies for control panels.
- Air ejectors for start-up and normal operation (condensing turbines only).
- Condensate pumps (condensing units only).

Gas Turbine Generators:

- Lube oil and seal oil system including reservoirs, pumps and coolers.
- Cranking motor, steam turbine or engine.
- Turning gear and motor.
- Distillate fuel system.
- Gaseous fuel system including gas compressor (if required).
- Cooling water system for lube oil and generator air coolers.
- A-C power supply for start-up.

TURBINE CONDENSERS

The steam turbine condenser is a steam-water surface condenser connected to the turbine exhaust. The exhaust steam is cooled to the liquid phase, collected in the condenser hotwell and then pumped back into the deaerator stage of the feedwater system.

Normal practice is to use a divided shell condenser to permit maintenance of one half while the turbine generator is in operation at reduced output, usually at 67% of rating.



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EQUIPMENT TYPES AND APPLICATIONS (Cont)**GENERATION AND DISTRIBUTION SWITCHGEAR**

This switchgear is the most critical part of the plant electrical system. It is usually the switching and protection center for the major circuits of the overall plant system.

ExxonMobil normal practice is to use single bus metal clad switchgear with drawout circuit breakers as contrasted to double bus type having a normal bus and a transfer bus for switching flexibility.

This switchgear usually contains all the protective relaying for generation and distribution circuits. However, generator protection has sometimes been located in a separate enclosure at the generator location. This decision is made usually on the basis of vendor responsibility. This switchgear may also contain excitation system elements.

For most power plant installations, the switchgear is located separately from the turbine generators and from the power plant control room. In these cases, switching of the circuits is always carried out by the control room operator using control switches located on the control room panel; control switches on the switchgear are for maintenance or emergency purposes.

Locations for the generator and distribution switchgear should minimize any possibilities of physical or fire damage. In some cases, a unit concept has been adopted which provides separate rooms for each major switchgear bus and for auxiliary switchgear associated with the turbine generator supplying the bus and for the associated boiler if a unit boiler-turbine concept is used.

FEEDER AND CONTROL CIRCUITS

- ▶ All of the important feeder and control circuits required for the plant system will usually be located in the power plant. The routing of circuits between generators, switchgear, and control room and for circuits leaving the plant must be selected to minimize damage possibilities. Unlike process substations, a cable vault is often the best answer for routing and protection (IP16-6-1, P.14.1). The vault should be equipped with smoke detectors and adequate lighting. Circuit routing in the vaults and in other parts of the power plant should provide spacing between dual power and control circuits so that a single incident will not affect both circuits.

SYSTEM DESIGN CONSIDERATIONS**DESIGN BASIS**

During the planning and early design stages, the design basis must be fixed so that the design specification includes all requirements needed to conform to the basis. Fixing the design basis requires close collaboration with the steam system designer, the electrical distribution system designer and with the Owner.

Expansion or revamp projects which require integration with an existing system place more constraints on the designer's alternatives than do grass roots projects. These constraints must be identified in the early planning design stage, if possible.

The designer must:

1. Identify all planned normal and abnormal operating conditions that the design must cover. This must include Owner's plans for operation of existing units.
2. Determine operational and capacity limitations of specific system design alternatives.
3. Obtain Owner's acceptance of the limitations or agree on required changes.

Following are some of the factors which must be considered:

- How must the new generating units operate on the system, i.e., base loaded, responding to electrical load changes or responding to steam load changes?
- Will the units act to control pressure of the various steam system levels in the plant or will this be done by existing turbine generators, boilers or pressure reducing stations.
- What are the foreseeable load ranges for the new units and what effect will this have on existing units.
- Will the boiler-steam turbine generator use the unit concept. If so, will the generator be connected through a step-up unit transformer to a higher voltage level or will it be connected directly to the power plant main bus having the same voltage level as the generator.
- For gas turbine generator units, how will waste heat be utilized, what is the range of waste heat utilization, and how does this range effect economics?
- Will the plant generation operate in synchronism with a public utility system?
- What provisions should be made to separate the in-plant system from the public utility when faults occur in the latter system?

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SYSTEM DESIGN CONSIDERATIONS (Cont)

- What are the effects on the in-plant system when it separates from the utility system and operates independently? Depending on the proportions of the total load supplied by in-plant generation and by the public utility system, the separation of the two systems can result in substantial changes in the loading of the generator. This, in turn, affects steam load and pressures.
- What are the requirements for pressure reducing system control and boiler control to cope with turbine generator automatic trips and steam system changes when in-plant generation separates from the public utility system?
- What provisions are required for initial startup operations? This requires establishing a tentative start-up sequence.
- What are the requirements for future expansion of the initial installation?
- What motor starting and reacceleration requirements will be imposed on the system and on individual turbine generator units?
- Turbine exhaust and extraction steam temperatures increase as load decreases. Start-up operations will dictate that units operate at no load and light loads during initial operation. Turbine extraction and exhaust flow-temperature characteristics may not be compatible with downstream piping, flange and equipment limits. The steam system design should include desuperheating facilities on extraction and exhaust levels unless specific turbine data is available which shows that desuperheating is not required.

ONE-LINE DIAGRAM

This diagram together with the system load data are the two most important tools for developing and presenting the system design. The one-line diagram is a graphic representation of all the important components of the electrical system such as generators, purchased power transformers, main busses and feeders, load center substations, etc. It also shows the basic protective relaying schemes.

- ◆ One line diagrams for design specifications should include all power and excitation circuits, including protective relaying and metering. The following specific information on components should be included:

Generators	Voltage, kW rating, power factor or kvar rating. Reactances (assumed or actual) x''_d – subtransient reactance x'_d – transient reactance x_d – synchronous reactance
Power Transformers	KVA (self cooled / forced cooled), fixed taps or range of automatic on-load tap changers, winding connections and voltages and impedance.
Circuit Breakers	Continuous current rating.
Busses	Voltage (all busses), calculated minimum and maximum short-circuit levels (generation and purchased power busses).
Neutral Grounding Devices	Resistance or reactance in ohms, taps if provided, and current rating.
Current Transformers	Number.
Potential Transformers	Number and connection.
Protective Relays	Number, ANSI function number, associated auxiliary or lockout relays, dotted lines to show breaker tripped or auxiliary relay activated.
Automatic Transfer Scheme	Dotted lines to breakers affected, "N.O." and "N.C." to indicate breakers which are normally open and normally closed.

In the planning stages of a design, the one-line diagram need not have all the details specified above. A diagram showing the arrangement of the power system main busses and feeders and load center substations and the size of major components such as generators, transformers, and feeds is sufficient.

LOAD DATA

The load data lists and summarizes the electrical load on the overall system and on system components. The load data is used to establish the capacity requirements for the various elements of the system. Load data summaries for the plant's normal and abnormal operating conditions will show which condition is determining. The various operating conditions should be evident from load data provided by process and offsite designers.

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The process and offsite designers provide the load data which is the basic input for the electrical system design. These data will be "normal" operating loads unless there are specific operating conditions which substantially increase or decrease the plant load. In this case, as many sets of input load data are required as there are operating conditions.

Load growth and reserve capacity factors are applied to the input load data during the course of the design to reflect the changes in the quality of the load data being used. Refer to [Section XXX-A](#), for rules on the application of load growth and reserve capacity factors.

SYSTEM GENERATING CAPACITY

In selecting the number and capacity of turbine generators, normal practice is to provide a reserve ratio of 1.25 minimum for grass roots installations. Usually this reserve ratio should be in the 1.33 to 1.5 range. For modifications to existing plants, reserve ratio should be based on actual load experience and demonstrated capacity of generating units. A reserve ratio of less than 1.0 is not advisable as experience has shown a rapid fall off in stability occurs when this threshold is crossed.

In establishing the capacity of individual generating units, attention must be paid to operating conditions which limit unit output. For non-condensing, non-condensing extraction and extraction condensing units, steam system operating conditions must be examined to determine their effect on output of a particular unit. Condensing unit capability decreases as condenser cooling water temperature rises. Extraction or non-condensing unit output may be limited by summer steam loads. Gas turbine generator capability must be adjusted to reflect site ambient temperature.

SYSTEM VOLTAGE LEVEL AND VOLTAGE PROFILES

Voltage levels for power generation facilities of the capacities usually found in ExxonMobil plants will be in the 4.16 to 15 kV range. In North and South America, 4.16 and 13.8 kV are nominal generating voltages most frequently used. In Europe and in countries following European practice, 5 or 6, 10 or 11 and 15 kV are commonly used.

Equipment and wiring costs, continuous current and short circuit current capabilities of available switchgear, and the voltage level of the public utility supply influence the selection of the voltage level. Each specific system design requires that a study be made of the significant economic and technical factors so that the most suitable level is selected.

For plant expansions, the starting point is the existing voltage level. The study must determine whether there is a sound basis for introducing a new voltage level.

The following preliminary assumptions for grass-roots plants can be made subject to confirmation for the specific design.

Installed Capacity	U.S.A. Practice	European Practice
Up to 10 MVA	4.16 kV	6 kV
10 MVA to 20 MVA	4.16 kV or 13.8 kV	6 kV, 10 or 11 kV, 15 kV
Above 20 MVA	13.8 kV	10 or 11 kV, 15 kV

Installed capacity includes all generating units and public utility supply transformers.

Voltage profiles for the plant system under normal and abnormal operating configurations and for motor starting and reacceleration should be made. These profiles show whether voltage at busses and at utilization equipment terminals are within acceptable limits. Adequacy of transformer tap ranges should also be verified. Equipment terminal voltage limits and acceptable system voltage drops are specified in [IP 16-2-1](#), *Power System Design*.

The PCMagnet or an equivalent program should be used early in the design specification phase to determine the generator transformer tap range and voltage profile. During the contractor's detailed engineering phase the tap range should be optimized/fine tuned based on the actual plant/vendor design data.

SYSTEM SHORT CIRCUIT LEVELS

The system short circuit level is determined by the kVA capacity, impedance and number of power sources, i.e., turbine generator and purchased power, which operate in parallel.

System short circuit calculations should be made to determine the maximum short circuit level for equipment rating purposes and the minimum short circuit level for motor starting and reacceleration and steady-state conditions. Minimum levels will cover abnormal conditions such as island operation of specific busses if this is an operating condition. The design basis for such conditions should be carefully assessed to insure that conditions which must be met are realistic. Particular attention must also be paid to minimum short circuit levels which result from early operation with less than normal capacity in service. All short circuit calculation methods should conform to the methods used for rating the equipment used. This information can be obtained from switchgear manufacturers if it is not known.

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All circuit breakers and bus and distribution feeders must be fully rated for the system maximum short circuit level. The maximum level should include any required provision for planned future capacity. The impact of the future capacity on alternative system designs should be assessed before the final bus and feeder arrangement is selected. This is particularly important where planned future capacity requires a change to higher interrupting capacity switchgear.

When high short circuit levels are present, for instance above 500 MVA at 13.8 kV, design alternatives should be considered which use reactors to reduce the level and permit use of lower interrupting capacity switchgear. For instance, reactors can be used in the stub bus-synchronizing bus connections or in feeders to distribution substations at the generated voltage level. When reactors are considered or applied, their effects on steady-state and motor starting and reaccelerating voltage conditions and system stability must be assessed for both normal and abnormal operating conditions.

♦ MAIN BUS ARRANGEMENTS

Some commonly used configurations for generator busses in the power plant are shown in **Figures 7 - 9**. In many cases, the initial plant will have two main busses connected by a tie breaker which is normally closed. One or two generators are connected to each bus. As the plant expands, short circuit and continuous current levels increase and use of reactors or a synchronizing bus with tie reactors is necessary to reduce the effect of added generation capacity and to stay within switchgear short circuit capability. In some cases, the "stub bus - synchronizing bus" concept has been used initially.

All bus arrangements must be checked for operating limitations when a generator or bus is out of service. For instance, motor starting capability on a stub bus may be severely limited when the connected generator is out of service and all bus load is supplied through the synchronizing bus. It is advisable to have a carefully thought out plan for expanding generation capacity to a level such as twice initial capacity before fixing the main bus arrangement. Adoption of a maximum connected capacity limit per bus provides system flexibility and avoids excess loss of capacity when a fault occurs. For example, capacity connected to a main or stub bus may be limited to a 15 to 25 MW range and additional busses added as more capacity is needed. Direct connection to grid via a generator step up transformer should be considered for a generator capacity in excess of 60 MW. This threshold may vary depending on the grid voltage available.

FEEDER ARRANGEMENTS

When determining the number of main bus feeder circuit breakers required to supply the plant load, the designer should assess continuous current capacity of feeder circuit breakers, location of load centers with respect to the power plant, the installed cost of feeder circuits and flexibility of the design. The designer must strike a balance which adequately utilizes the capacity of the feeder circuit breakers and retains sufficient flexibility for maintenance purposes. A 13.8 kV feeder circuit breaker rated 1200 amperes can carry 28,600 kVA without exceeding its continuous current rating.

Assuming all loads require dual supplies from the power plant, a suggested starting point is two feeder breakers for process loads, two for power plant and adjacent utilities services and a third pair for offsite and other utilities services. A check should be made of feeder load versus breaker capacity and whether an alternative routing of feeders is more economical even if additional circuit breakers are required.

SUPPLY TO POWER PLANT AUXILIARIES

The aim is to provide feeders which are as independent as possible, so that the effect of a single fault is limited to a minimum. Also, the design must be checked to see if it is suitable for the initial start-up and for subsequent start-ups and shutdowns. This is particularly critical where no purchased power connection is available and the plant must be "boot strapped" from a construction power supply or a small emergency generator. Normally power is first required for plant and instrument air, treated water, cooling water and fuel pump services and for instrument power and lube systems to get the boilers in operation. It is sometimes necessary, where construction power is limited, to make special or temporary provisions for running the larger services such as boiler fans, feed pumps and cooling water pumps whose drivers may be medium voltage motors. In the case of gas turbine generators, the start-up problem is somewhat simpler since the unit can be supplied with a starting turbine or diesel engine and electric power may be needed only for fuel pumps, instrument power supply, and heaters. However, the specific requirements for each installation should be checked. The designer must review the start-up procedure with the steam system and rotating equipment engineers to insure that the system arrangement for the power plant auxiliaries is suitable.

The designer should avoid situations where one or several drivers of auxiliaries needed for power plant operation requires extensive energizing of distribution facilities outside the power plant block. This is not always possible but the extent should be held to the practical minimum.

Figures 10 and 11 are the typical feeder arrangements for supply to process substation and power plant auxiliaries.

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Where very large turbine generators are unit connected, each through a unit transformer to a higher voltage system, auxiliary loads may be supplied from the unit auxiliaries' transformer connected at the generator terminals. A start-up supply connected to the secondary bus supplied by the unit auxiliaries' transformer should be provided. The start up supply may be from a second unit generator or from an outside source. **Figure 12** illustrates this arrangement. Alternatively, two separate feeders from outside sources may be used with bus arrangement as shown in **Figure 10**. Note that, to restore power after a total plant failure, an independent power source is required.

When an outside source such as purchased power or a supply from a second power house is available, using this source for one of the two sources for auxiliaries will usually provide protection against failures which could shutdown all sources integral to one power plant.

SYSTEM PROTECTION

Within economic limits, the system should be designed so that it can be adequately protected. This means that first-line protection is provided to protect the system and its equipment from abnormal conditions including short circuits and that back-up protection is provided for short circuits. The protection should provide prompt removal from service of any system element which has been short circuited, or operates abnormally so as to damage the element, or interfere with effective operation of the rest of the system.

Adequate protection also requires that first-line and back-up relaying is sensitive, selective and fast. It must be sufficiently sensitive to operate reliably under minimum fault conditions. It must be selective to distinguish between conditions which require instantaneous operation, time delay operation, or no operation. It must disconnect faulted elements as rapidly as possible to minimize damage and upset on the system.

First-line and back-up protection for generator, main bus and main bus feeders should aim to clear phase faults, and preferably ground faults, within one second for normal short-circuit level faults. Protection for busses at the same voltage level as the generation bus but electrically closer to utilization levels should be faster and operate first for faults in utilization equipment and circuits.

To meet these fault clearing times, differential and/or pilot wire protection and instantaneous phase and ground overcurrent protection is usually required for busses and feeders at the generator voltage level.

In systems having three or more busses, series connected at the same voltage level, back-up clearing times above one second may have to be accepted. Sometimes, faster clearing times can be obtained by application of directional phase and ground overcurrent relays at tie breakers to isolate parts of the system if first-line protection fails.

Figures 13 - 16 illustrate system and generator protection used in two multiple bus systems and in a dual main bus system installed at three ExxonMobil plants.

SYSTEM AND GENERATOR NEUTRAL GROUNDING

Selection of the neutral grounding method is a critical design choice which must be made early in the design specification phase.

U.S.A. and ExxonMobil normal practice is to use low resistance grounding for medium voltage systems. In Germany and in countries following German practice, ground fault neutralizers (resonant grounding such as Petersen coils) are used for grounding the system neutral.

High resistance grounding is another method of neutral grounding. It is used to limit ground fault currents to very low values, to alarm only on ground faults and permit operation to continue without tripping the grounded circuit. The ground fault current must not be less than the system three phase charging current. Generally, the use of high resistance grounding in systems where the ground fault current will exceed 10 amperes should be avoided. This will generally limit use of this type of grounding to generators connected to the distribution busses through unit transformers, i.e., without distribution circuits at the generator voltage level. It also finds use in power plant auxiliaries substations where there is a large incentive to avoid power plant upsets which occur if a circuit supplying a boiler feed pump motor or forced draft fan motor tripped.

The system neutral of the low-resistance grounded system may be grounded at one power source only, even though several source neutral points are available. This arrangement has the following characteristics:

- Fault current flow paths are usually less complex and it is easier to limit ground fault magnitudes than in multiple grounded neutral systems. Ground fault current equal to full load current of the largest generator or 400-amperes minimum are typical values.
- All bus tie breakers must be normally closed. When a tie breaker opens automatically, parts of the system become ungrounded.
- Directional ground fault relaying which sees across tie breakers plus logic circuitry is required to ensure that all fault conditions will be cleared even if ground fault current flow ceases when a bus tie breaker is tripped.



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SYSTEM DESIGN CONSIDERATIONS (Cont)

- To avoid ungrounded operation of part of the system, it is necessary to provide logic or control circuits to permit switching the system neutral ground to a second source if the normal source trips or the system splits into independent islands after specific fault conditions.
- Neutral switching equipment, either circuit breakers (preferred) or load-break switches are required for the neutral of each generator having its neutral grounded. When drawout circuit breakers are used, it is possible to provide as few as two drawout elements. One is for the generator which is grounded; the second, for the generator which will be grounded if the first is tripped. The neutral switching equipment should have provisions for remote tripping and closing from the control room and by the required logic circuits.

Multiple grounded neutral sources may have advantages for particular situations such as those involving multiple stub bus-synchronizing bus arrangements. It should be noted that multiple grounded sources will usually mean higher ground fault currents than single neutral point grounding. Also, particular attention must be paid to ground fault current paths to insure that protective relaying maintains selectivity under all operating conditions and fault locations, particularly when the system is split into islands.

Where multiple system grounded sources are used, ground fault current levels should not, in general, exceed the 1200 to 1600 ampere range. Above these levels, the benefits associated with resistance grounding are reduced. Where a system has undergone several expansions or modifications such as adding purchased power connections, it may not be practical to stay within the range mentioned. In this case, 2400 amperes is the next maximum limit recommended although at least one technical reference puts 4000 amperes as the outside maximum limit.

Where complex generation systems are involved, such as those involving separate powerhouses each with multiple units or multiple bus systems, special studies must be made of system grounding alternatives including the use of grounding transformers, so that the best method can be selected. These studies should cover all planned system operating conditions and determine the levels of ground fault current which results for ground faults occurring on the various busses and feeders. These studies should confirm that first-line and back-up protection is provided for all conditions.

KILOWATT (REAL POWER) CONTROL

The turbine governor controls the kilowatt or real power output of the turbine generator. The governor acts on the steam turbine inlet valves or on the gas turbine fuel valve to change the unit's power output.

Steam turbines may operate on speed control (all turbine types) or on pressure control (non-condensing and extraction condensing turbine types).

Speed control has two modes available - isochronous control and speed / load or droop control. Speed / load control is normally used.

The isochronous mode restores the unit to the pre-set value after a load change. Isochronous control of one unit can be used to maintain system frequency in plants which operate independent of a public utility system and where close frequency control is important. The unit on isochronous control must have sufficient range to absorb all load changes. This limits the mode to condensing units or gas-turbine units.

Speed / load or droop control utilizes the governor's negative max/min droop characteristics. That is, unit speed drops with an increase in load and rises with a decrease in load. For instance, with a 5% negative droop or speed regulation, the unit speed will decrease 5% between no load and full load. Governor adjustments permit different reference speed settings so that the turbine speed can be set between 100 to 105% of rated speed at no load. With 5% droop this results in 95% to 100% speed at full load. Normally, the reference setting is selected so the unit is at rated speed at normal operating load.

When two or more units operate in synchronism on speed / load control, and are not synchronized to a public utility system, load changes cause a change in both units' speed and system frequency. If the two units have the same reference max/min droop setting and are the same rating, the load change is shared equally. Different size units will share in the same proportion as their ratings if the same reference setting is used. With different reference settings, a plot of the settings on a speed versus load basis is necessary to determine how load changes will be shared. Since a change in load will cause a change in system frequency, the system must be returned to normal frequency when the change occurs.

When units operate synchronized with a public utility system, the public utility fixes the frequency. Electrical load changes without a corresponding increase or decrease of steam to the turbine inlet or fuel to the gas turbine are reflected as changes in power supplied by the public utility.

Pressure control for non-condensing and extraction turbines provides a signal from the pressure sensor to the inlet and/or extraction valves to cause a change in inlet steam flow and a resultant output change. This causes a shifting of electrical load between paralleled units.

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SYSTEM DESIGN CONSIDERATIONS (Cont)**KILOVAR (REACTIVE POWER) CONTROL**

Generator kilovar output and, therefore its power factor, is controlled by action of the voltage regulator that changes the field current (excitation level) and thus the generator terminal voltage.

When a single isolated unit is supplying the load, the load's power factor fixes the kilovar output. When more than one unit operate in synchronism to supply the load, or when one unit operates in synchronism with a public utility system, reactive power production can be shared between the sources within the limits set by each unit's kvar capability. The sharing is controlled by the droop setting of the voltage regulator. Reactive droop compensation is normally used. It creates a droop in generator voltage proportional to the reactive current and equivalent to that which would be produced by inserting a reactor between generator terminals and the paralleling point. This droop is required for stability of operation and prevents paralleled units from transferring reactive circulating current from one unit to another through action of the individual voltage regulators. In general, satisfactory sharing of reactive load will be obtained if there is from four to six percent reactive voltage drop between paralleled units.

SYSTEM STABILITY (References contain additional information on stability in industrial plants.)

General - Stability can be defined as the capability of the electrical system to develop restoring forces between its elements which are equal to or greater than the disturbing forces so as to restore equilibrium between the elements of the system. The system needs this capability for both steady-state and transient conditions. Stability can also be defined as the tendency of the power system and its components to remain in synchronism or "in step"; instability is a loss of synchronism or "falling out of step".

♦ **Steady-State Stability** - Steady-state stability refers to the ability of the system to transfer power free from sudden change in MVAR/Voltage and frequency /MW for gradual application of real and reactive load. The steady-state limit is the maximum power level that can be transferred. Steady-state stability is hardly ever a problem in properly designed industrial systems. Satisfactory steady-state voltage levels throughout the system are usually indicative of systems which will be stable in the steady state.

Transient Stability - Transient stability for the industrial system means that, during and after sudden disturbances, generators and synchronous motors remain in synchronism and induction motors do not stall. The sudden disturbance can be a sudden application of load. However, most often in the industrial system, it is a fault or a combination of the fault and its subsequent isolation by tripping part of the system.

Fault Effect on Transient Stability - Transient stability is affected by the type, location and duration of the fault. Three phase faults electrically close to the generator terminals have the most severe effect on transient stability since the voltage at the fault point is zero on all phases. There can be no synchronizing power flow past the fault point between the paralleled generators to hold or pull the units back into synchronism. In addition, the power flow from the generator is cut to zero and all the mechanical energy input to the turbine is transformed into rotational energy and accelerates the turbine and generator rotor system.

In the case of phase-to-phase, phase-to-phase-to-ground, and single-phase-to-ground faults, not all phase voltages go to zero. There is some synchronizing power flow and less mechanical energy input is converted to rotor acceleration and the overall effect on stability is less severe than for the three-phase fault.

Fault clearing time has an important effect on the ability of the system to keep rotating equipment in stable operation. The results of studies on industrial systems have shown that, in general, systems proved to be stable if 3 phase faults on strategic circuits are cleared instantaneously or within 0.25 seconds.

Stability and Power Angle Value - When system stability studies are made, one rule of thumb is that the system will be stable if the power angle between the generator voltages behind the transient reactance of paralleled units does not:

1. Exceed 90 degrees during fault clearing, and
2. Exceed 140 - 160 degrees during the recovery swings after fault clearing.

In less rigorous calculations, the synchronizing power flow between paralleled units is taken to be directly proportional to the sine of the power angle.

Conditions Promoting Instability - Conditions which increase possibilities of instability during and after fault clearing are:

- Different inertia constants, (H), for paralleled generator-driver units, i.e., one unit's $H = 2\text{kW-sec/kVA}$, another at 4, a third at 10.
- Generators paralleled through high reactance synchronizing ties and/or with a large ("weak") public utility system.
- Absence of differential or instantaneous relays on circuits which are electrically close to the generator.

