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REPLACING A DISTRIBUTION SUBSTATION

Options and considerations

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THERE ARE SEVERAL FACTORS TO consider when replacing a distribution substation. Establishing the electrical configuration, considering the process, determining equipment sizes and ratings, and deciding what options to include (and calculating their relative initial cost) are all part of creating the best design for a project. An electrical power loss or interruption during operating periods is not an acceptable option at most refining facilities, which makes it difficult to conduct electrical maintenance

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and tie-ins. Aspects such as safety, capacity, expandability, and cost must also be considered to ensure that the installed design offers real, long-term benefit and value to the organization.

Although the absolute minimum equipment sizes and ratings can always be determined, it is more valuable to find the best balance between preinvestment and costs. This article will describe some of the options and considerations that were evaluated at the distribution substation level for a large petroleum refinery and how those decisions led to a degree of standardization for the electrical configuration.

The focus of this article is on the distribution substation level. Design considerations, equipment and construction options, and a per-unit cost comparison will be discussed. Careful planning at this level in the system will help ensure that future expansions and investments will align with these upgrades. Any extra preinvestment money spent offers long-term benefits to safety, reliability, maintainability, and expandability.

The Master Plan

This facility's master electrical plan (MEP) allowed its substation options to be evaluated. The MEP is a plant-wide, comprehensive plan that guides the development of preliminary parameters, boundary conditions, and standardization concepts for electrical power upgrades throughout the facility.

The MEP was developed by a diverse group of stakeholders, including engineers, technicians, maintenance and reliability personnel, and project managers. Its primary purpose was to promote awareness of electrical infrastructure; evaluate how key decisions could promote real, long-term value; and provide the basis for future substation specification and design parameters.

It can be very difficult for a plant electrical engineer to convince project managers and funding gatekeepers that certain aspects of an electrical substation offer real, long-term value. Therefore, electrical equipment replacement and upgrades are difficult to fund. The extra investigations and discussions that took place during MEP development at this particular petroleum plant allowed for a thorough, comprehensive analysis that created the basis for the parameters discussed in this article.

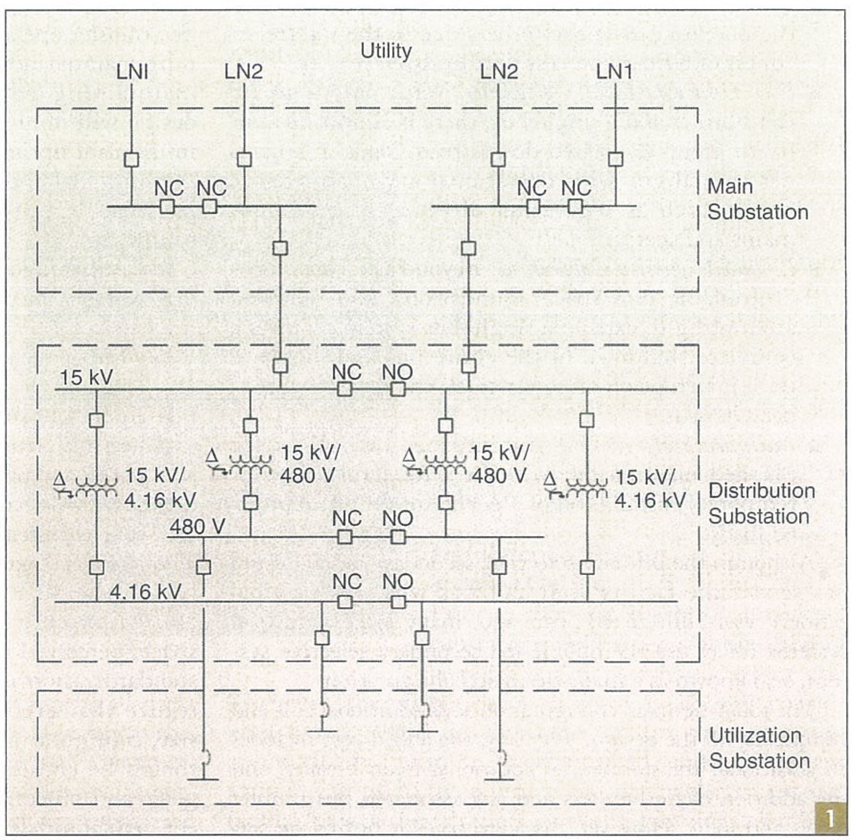
System Topology

The existing plant's electrical distribution system can be broken down into three distinct levels: 1) main substations, 2) distribution substations, and 3) utilization substations. A simplified, overall block diagram of these three levels is shown in Figure 1.

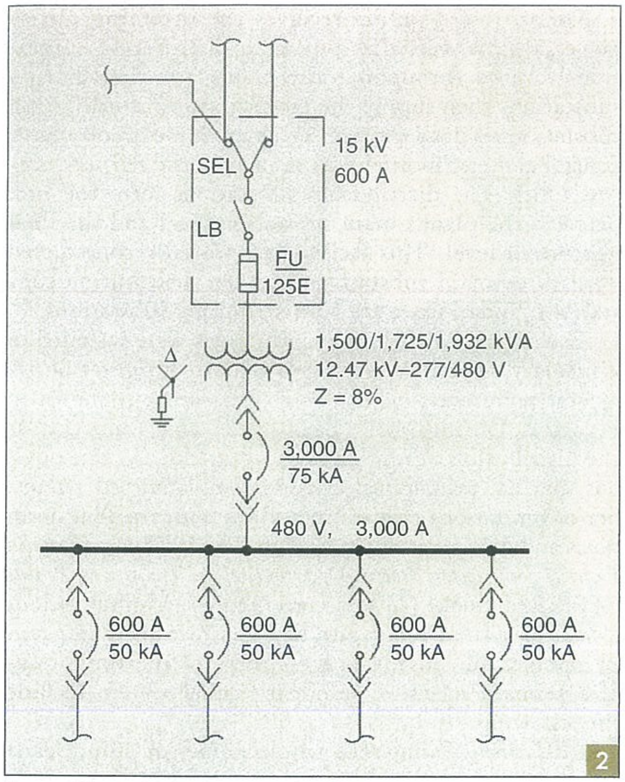
The main substation receives the incoming utility power and delivers that power to distribution substations located throughout the plant. The distribution substations then supply the power to various utilization substations or load centers (i.e., switch racks and motor control centers) located within or near the refinery process units. The distribution substations form the link between the plant's main substation level and the final utilization level. This facility was initially constructed with three main substations and ten distribution substations. Today, there are 15 distribution substations.

The original distribution substations were installed in a primary selective, secondary radial configuration. A typical representation of this configuration is shown in Figure 2. During MEP development and evaluation at the distribution substation level, it quickly became obvious that the primary selective system contained a number of limitations that did not align with the long-term goals and objectives of the facility. The *IEEE Recommended Practice for Electric Power Distribution for Industrial Plants* (IEEE Red Book) [1] was consulted to examine various electrical system topologies and consider their inherent advantages and disadvantages. Some of the limitations of a primary selective, secondary radial system include the following:

- *Reliability:* Numerous single points of failure exist (e.g., a single primary selective switch, a single transformer, a single bus, a single main breaker, and cable terminations). A failure at an inappropriate location on this electrical system will impact all



The plant's electrical distribution levels.



The existing plant primary selective, secondary radial distribution substation.

loads directly connected beyond that point and has the potential to impact others due to the interrelatedness of refinery process unit loads.

- *Poor Unit and Load Segregation*: With only a single transformer and a single bus, there is almost no ability to group associated downstream loads in a manner that aligns with operational and maintenance needs (such as separation of process equipment mains and spares).
- *Limited Expansion Capabilities*: Beyond the constraints of available plot space, foundations, and the like, attempting to expand a single-bus system requires a complete shutdown of the entire bus and, hence, a total interruption of power to all the respective connected loads.
- *Maintainability*: The system does not allow for planned maintenance without a total shutdown or temporary installation of a generator for all connected loads.

Although the primary selective, secondary radial design has served the facility well and was what the original refinery was built to 40 years ago, many large industrial systems today use the double-fed secondary selective system, also known as a main-tie-main configuration.

The main-tie-main configuration adds additional cost and complexity to the design. Typically, the added cost includes an additional transformer, an additional main breaker, and the addition of tie breakers and any associated bus transfer relays and logic. However, the advantages it brings are significant compared with the primary selective system:

- *Reliability*: The main-tie-main configuration eliminates numerous single points of failure.
- *Load Segregation*: Main and spare loads can be separated and fed from different buses to allow continuous process operation in the event of a bus failure or maintenance outage. Although a planned bus outage requires careful planning downstream at the load center level, planned maintenance can be carried out with a double-bus configuration.
- *Expansion Capability*: Only a portion of the switchgear, usually a single bus, needs to be taken out of service for lineup expansion.
- *Maintainability*: Portions of the electrical system can be taken down without an interruption in service to the plant.
- *Cost*: Although the initial cost of a main-tie-main is higher than a primary selective, secondary radial system, the total interruption time on downstream loads can be greatly reduced, allowing for much quicker equipment restarts and restoration of normal plant operations.

Because of the overwhelming advantages of the main-tie-main configuration, the first decision made at the distribution substation level was to standardize the basic arrangement. Once that decision was made, other, more specific, considerations and options were evaluated.

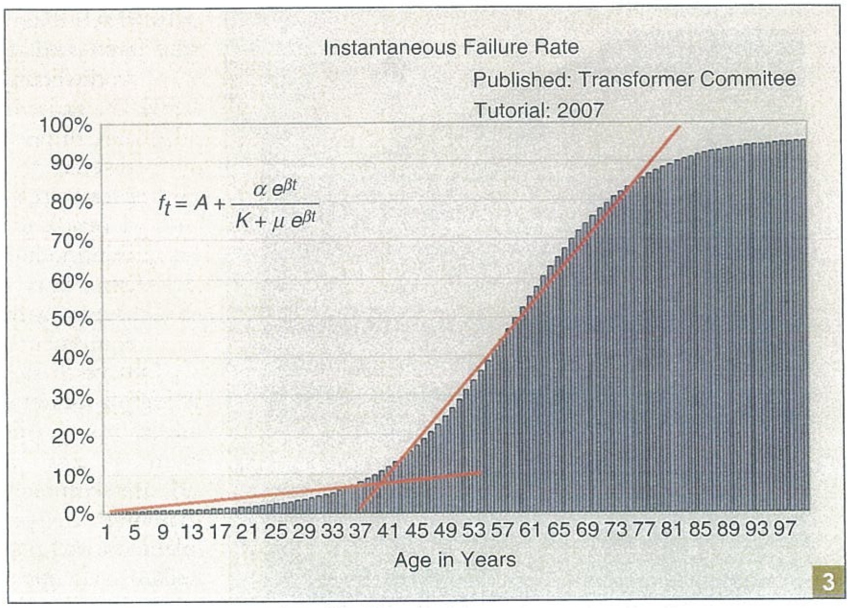
Distribution Substation Options

A properly selected distribution substation can become the backbone of the power system network. It can create main substation extensions, be called upon to do critical bus transfer operations, be laid out to enhance and maximize maintenance accessibility, and play a critical role in maintaining power to downstream systems. Proper design will minimize operational interruptions and maximize plant uptime.

Some key considerations when trying to standardize, plan, specify, or design at this level include the following:

- whether indoor or outdoor equipment will be used
- whether the substation will be prefabricated or built on site
- whether the substation will be elevated or constructed on grade
- equipment standardization
- heating, ventilating, and air conditioning (HVAC); purge; and pressurization units
- supervisory control and data acquisition (SCADA) and control systems.

The above categories were considered and evaluated as part of the MEP development for this particular refinery, based on a cost–benefit analysis, available plot space, perceived reliability, and other factors. Although standardization is important, it is just as important to realize that every replacement project is unique. The size, configuration, and options selected for a substation should be chosen to add the most value to the overall goals and objectives of the plant and the specific project. Although each distribution substation replacement will not follow all guidelines every time, for the majority of replacements, the plan developed and described herein may be seen as a starting point for distribution substations.



A failure probability curve for utility transformers.

Reliability Versus Risk

The original substations installed at the facility in 1971 were all outdoor-rated lineups with slab-on-grade construction. Although these have served the plant well for more than 40 years, they are rapidly reaching the end of their useful life and are starting to fail at an increasing rate.

The life expectancy of major electrical equipment can vary widely based on a number of factors, such as the quality of materials, workmanship, maintenance, electrical loading, and environmental causes. An IEEE Petroleum and Chemical Industry Committee (PCIC) paper presented in 2010 [2] provides insight on when to replace aging transformers. Although trying to predict the exact day of failure is almost impossible, there have been numerous studies conducted depicting average or probable failure rates. One study conducted by an IEEE Transformer Committee [3] developed the failure graph shown in Figure 3. The magnitude of the actual failure rate by year is not necessarily the most important part of this graph; the slope of the failure line is more important. At about 40 years, this slope dramatically increases, which means the probability of failure increases.

There is more to consider than probability of failure and life expectancy when it comes to older equipment. Obtaining spare parts becomes more difficult as time passes and systems age.

Many petroleum refineries have developed and established their own risk-analysis tools and matrices. The matrices are typically composed of two categories: probability and severity. At the distribution substation level, with a primary selective, secondary radial design, any failure represents high severity in plant operation and may impede the ability to conduct safe and orderly shutdowns. In addition, electrical power loss can translate to significant profit loss.

The interruption of plant operation, the inability to complete regularly scheduled maintenance, and the effects of corrosion created by the outdoor environment all came together to make replacements increasingly necessary at this particular plant. Because the plant was originally constructed—and had been operating for several decades—with outdoor-rated equipment, one of the first criteria considered was the benefits of indoor- versus outdoor-rated equipment.

RAIN, WIND, TEMPERATURE, AND HUMIDITY ARE IMPORTANT FACTORS TO CONSIDER WHEN PLANNING A SUBSTATION.

Specific Considerations

Indoor- Versus Outdoor-Rated Equipment

Rain, wind, temperature, and humidity are important factors to consider when planning a substation. After evaluating the outdoor equipment in terms of maintenance and reliability, this plant decided that placing all equipment indoors would make maintenance, troubleshooting, and tie-ins more manageable and tolerable. Although having a separate building with indoor equipment does have some obvious advantages, other factors, such as project costs, had to be carefully considered as well; specifying separate buildings with indoor gear as opposed to outdoor equipment poses a significant financial impact.

The decision to use indoor equipment and separate buildings also applies at the main substation level and at the utilization or load center level. As part of the MEP, the plant is conducting downstream upgrades and expansions with indoor-rated medium- and low-voltage motor control centers in lieu of outdoor-rated switch racks.

Prefabrication Versus Building On Site

Prior to adopting the MEP, almost all substation replacements at the facility were for buildings constructed on site. Therefore, the prefabrication option was carefully considered during MEP development. In the prefabrication approach, the building is constructed, and the interior switchgear, SCADA, alternating current/direct current (ac/dc) power distribution, and the like are assembled together, usually at the building fabricator's site. The


(a)


(b)

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(a) A substation with (b) an underground basement. (Used with permission from BP.)

build-on-site option means that the physical building is constructed on site, and then all of the ancillary systems and main switchgear are installed and connected. The primary differences between the two possible scenarios, including the pros and cons of each, were considered, and eventually the prefabrication option was selected. Three key considerations drove the decision.

1) There would be less actual in-plant construction. Depending on the location and labor specifics, on-site construction can easily add to the overall cost per square foot. Additionally, more field-labor hours inherently bring more on-site safety risks.
2) More complete testing could be conducted at the factory prior to shipment. With prefabrication, systems that are interrelated, such as switchgear and SCADA, are tested at the fabricator's facility, and the bugs are worked out prior to arrival at the plant site.
3) The switchgear would not have to be disassembled and shipped to its final destination after a factory test at the switchgear manufacturer's facility. A prefabrication design may require shipping splits, depending on the size and quantity of transportation modules, but with careful layouts, the switchgear can be completely contained within a shipping module and thus maintain all internal equipment wiring.

Even with the prefabrication approach, there is still a lot of plant-site construction needed to interconnect module shipping splits, install and connect exterior equipment (such as transformers and bus ducts), and complete all site-acceptance testing and commissioning exercises. Although the prefabrication option was chosen for this plant, careful planning, engineering, and scheduling are still crucial. Attention to transportation logistics, lifting plan development, and continuous coordination with the fabricator and state and local jurisdictions are all essential to help ensure that the substation modules arrive at the facility immediately ready to lift and set upon the foundation.

Elevated Versus On-Grade Construction

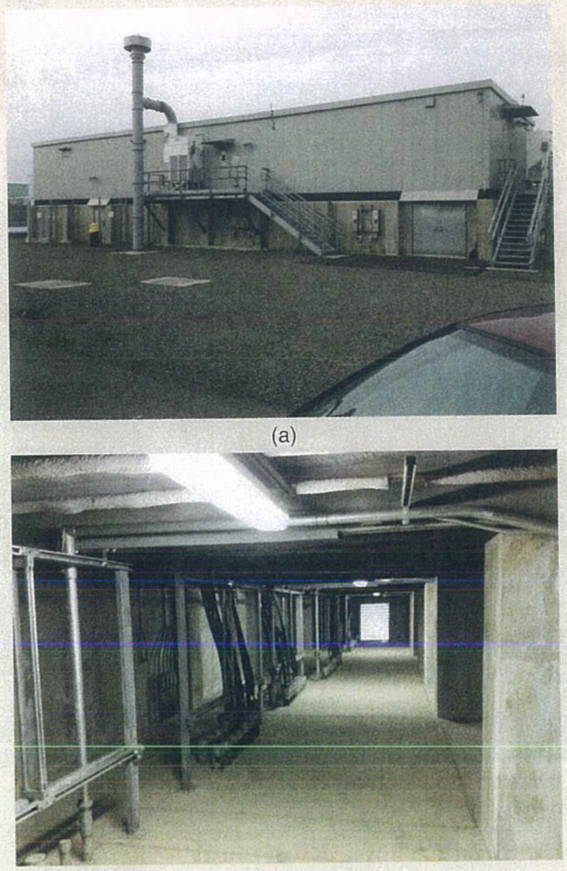
The original substations installed at the facility in 1971 were all outdoor-rated equipment with slab-on-grade construction. Before the MEP adoption, the substations that were replaced were constructed with indoor-rated equipment in buildings built on site with full underground basements. Over time, it became obvious that significant funding allowance and schedule durations were required for this type of construction, primarily due to the tremendous amount of earthwork involved and the subsequent hazards (e.g., shoring and confined space issues). Figure 4 shows a substation at the facility with a full underground basement.

The issues given previously, combined with the fact that new feeders into or out of the substation are rarely added, created an environment to study other more cost-effective means of supplying loads. Overhead routing, solid slab foundations with conduit stub-ups, partial elevation with cable trays, full elevated construction, and other options were all considered and evaluated.

The vast majority of MEP participants were fully supportive of a full elevated approach in lieu of a partial-elevation or slab-on-grade concept. The primary factors that influenced this decision were the ease of future cable installation and design flexibility, along with underground cable routing. However, elevated construction is more expensive than slab-on-grade construction, typically requiring piles and pillars or piles and grade beams. The extra cost is associated mainly with the exterior walls and the extra effort required to form and pour support pillars. The MEP estimate comparisons for a 30-ft-wide by 80-ft-long prefabricated substation with four shipping split modules indicated that elevated construction would be approximately 35% more costly than slab-on-grade construction. For a pile and pillar foundation, the cost would be in the range of US$120,000–US$140,000. Eventually, the decision was made to standardize on an elevated substation with an enclosed, above-ground basement.

The first distribution substation module was designed and placed on columns that were 6 ft, 10 in above the finished grade. All incoming and outgoing conduits were routed under the daylight basement floor and stubbed up directly below the subject switchgear. This type of construction minimized shovel time, allowed for underground cables to easily transition up into the electrical equipment, and avoided below-grade water and confined-space classification issues.

Figure 5 shows the elevated construction method; note the fully enclosed daylight basement. During design, it was decided to include a fully enclosed basement instead of an open one. This decision was driven primarily by the local weather patterns and vermin in the area that frequently build nests or chew on power cables. Although there are walls between the perimeter support columns, they do not structurally support the upper substation module and are therefore fairly cost effective to install.



(a)

(b)

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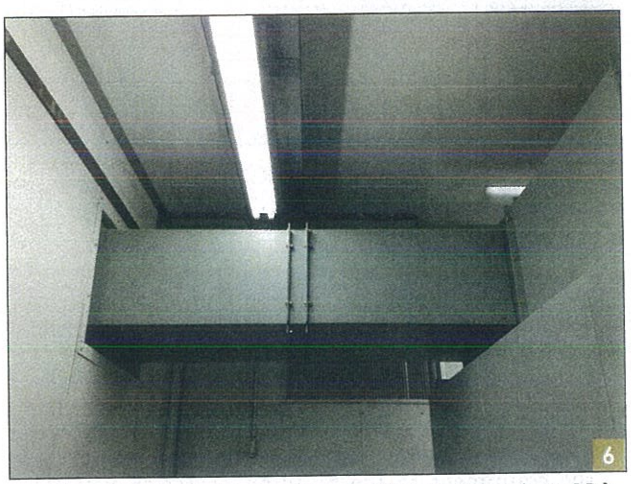
(a) A substation with (b) an above-ground basement. (Used with permission from BP.)

Equipment Standardization

Equipment standardization was one of the most important considerations when designing a substation. Of the equipment considered, transformers and switchgear were the most important. Note that the standardization was not original equipment manufacturer oriented but rather was based primarily on the transformer voltage and kilovoltampere ratings as well as the switchgear bus ampacity and short circuit duty withstand ratings. Another consideration regarding the switchgear was whether or not to specify arc-resistant construction.

The actual cost of arc-resistant switchgear over standard construction depends on the switchgear voltage level and the number of cubicles (or breakers) that are contained in the lineup. As a general rule, arc-resistant construction costs about 10% more per unit. For the most part, arc-resistant switchgear does not require much more attention to detail than standard switchgear, with the exception of the exterior blast vent.

The primary focus of arc-resistant switchgear is to protect nearby personnel from the byproducts of an arc-fault event. Typical 5- and 15-kV switchgear lineups require a large plenum space to handle the rapidly expanding gases, pressures, temperatures, and metal fragments (i.e., shrapnel) resulting from an arc-flash event. Blast plenums, as shown in Figure 6, are usually installed along the top of the switchgear and directed to vents on the building's exterior wall. Although the plenums and vents by themselves are not concerning, the expulsion of hot gases and shrapnel is significant.



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A switchgear blast plenum. (Used with permission from BP.)

Switchgear manufacturers recommend an isolation zone surrounding exterior blast vents. It is suggested that this zone be kept free of personnel, sensitive equipment, and other items that may impede gas expulsion from the vent, become damaged, or result in an injury should an event occur. For this application, the isolation zone can be thought of as a cylinder that is approximately 5 ft in diameter and extends 7 ft out from the exterior blast vent location.

Since the arc-resistant switchgear design was standardized, other personnel safety factors had to be considered. For this facility's elevated construction approach, considering the environmental factors of wet weather and the arc-flash isolation zone, panels on the building exterior allowing access to the outgoing termination compartments of the 5- and 15-kV switchgear were not installed.

An isolation zone for blast vents. (Used with permission from BP.)

A warning for blast vents. (Used with permission from BP.)

Instead, this gear was housed completely inside the building with enough space (approximately 4 ft) from the rear of the equipment to the building's exterior wall. This allowed for de-energized work, including incoming and outgoing terminations, to be done inside, away from environmental factors and not requiring exterior compartment access (via grade or platform) next to potential blast vents. Additionally, since the space directly below the blast vents could contain hot metallic particles carried by the rapidly expanding gases, the area was fenced off to keep personnel and flammable products out of harm's way (Figures 7 and 8).

For the transformers, standard kilovoltampere sizes were selected for 480-, 2,400-, and 4,160-V secondaries. Even among different original equipment manufacturers, this standard base-rating selection results in more consistent physical dimensions, similar secondary fault current values, and more consistent termination points. While developing the MEP, a thorough load evaluation was conducted throughout the facility to determine the best value of kilovoltampere standardization, and the best midrange value was selected. In the cases in which the load is larger than the standard kilovoltampere size, more transformer and switchgear lineups may be added. In the cases in which the load is significantly smaller, smaller kilovoltampere transformers may be used. The real benefit results from finding the best balance between cost and value.

As mentioned, arc-resistant switchgear construction is the standard, but other critical aspects were decided while planning a substation as well, e.g., bus and breaker ratings, which were influenced primarily by the transformer selection described previously. Standardizing the bus and breaker ratings allows for less spare inventory and better consistency between similar distribution-type substations. Other details of the switchgear lineups were also included in the plan, such as the need to use consistent, solid-state, protective relay models and two-tie breakers.

When a two-tie breaker concept is presented, it usually falls into one of two categories: old news or nothing new. It can be hard to understand why a lineup should have two ties; after all, the term *main-tie-main* implies only one tie. The addition of a second tie, although not intuitively obvious, becomes clear when considering the ability to take a complete bus, including the tie, offline for maintenance or inspection. Under a typical main-tie-main configuration with a bus transfer scheme, the tie breaker needs to be as smart and reliable as the mains; that is, it is called to do specific operations under bus transfer conditions similar to the main breaker. Unfortunately, this single (smart) tie is associated with both buses, and, since it is equally as important as any respective main, it cannot be placed totally out of service for maintenance and testing with respect to the horizontal bus connections. With the addition of a second tie (main-tie-tie-main), the active (smart) tie and its associated horizontal bus work can be completely isolated.

The final, and possibly most critical, item discussed regarding the equipment standardization was the inclusion of a 15-kV switchgear lineup at the distribution substation level. Many possible scenarios were evaluated regarding handling the incoming 15-kV power from the main substations. The configuration of daisy chaining individual primary selective switches that directly supply transformers and using a group lineup of primary fused disconnects were considered.

The additional cost of using 15-kV switchgear played a major part in the evaluation. The addition of a 15-kV switchgear lineup, while offering many advantages, significantly adds to the overall cost of a distribution substation compared with a fused-switch assembly with two incoming sources and a normally open tie section. The final costs can vary based on the complexity of the design (e.g., bus transfer schemes and single versus two ties) and the number of feeder sections. In general, specifying the 15-kV switchgear added approximately 350% more initial cost than a fused-switch lineup.

Eventually, through careful evaluation, the standard included the 15-kV switchgear. Although the inclusion added a significant cost to the distribution substation, the benefits of having a main substation extension at the distribution level are numerous, including the following:

- easier implementation of selective coordination between the upstream main substation feeder breaker and the incoming main breaker on the substation switchgear
- the ability to implement a higher-level, automatic bus transfer scheme that maintains better downstream load distribution if an incoming feeder fails
- the ability to easily expand a distribution substation should future transformers and switchgear be required
- the capability to supply large electric motors directly at 15 kV or at a lower voltage level via a captive transformer
- the reduction of the total number of substation breakers at the main substation level by extending the 15-kV switchgear down to the distribution substation level
- easier implementation of transformer differential protection by having the transformer feeder breaker close to the transformer and secondary switchgear, providing a good zone of protection with rapid tripping characteristics and significantly lowering arc-flash incident energy levels and resulting personal protective equipment requirements.

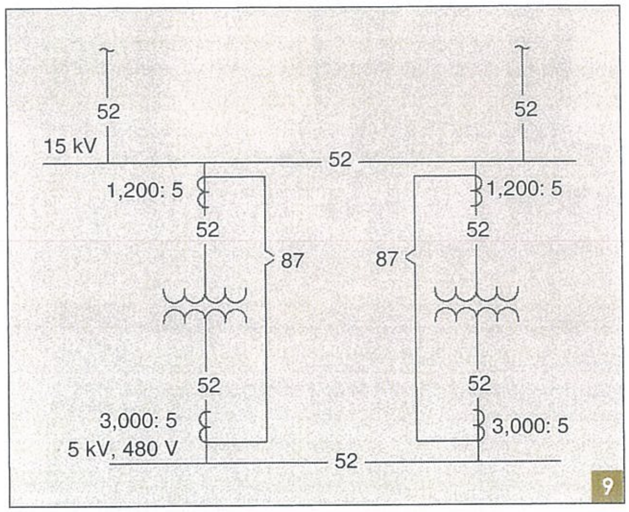
The transformer differential protection can be difficult to implement if the transformer is supplied directly by a fused disconnect switch or a feeder breaker from a main substation some distance away. By having a 15-kV lineup at the distribution substation level, both primary and secondary breakers can be included within the differential zone, thereby completely isolating the transformer from the line and load side. A simplified diagram of this differential scheme is shown in Figure 9.

THE REAL BENEFIT COMES DOWN TO FINDING THE BEST BALANCE BETWEEN COST AND VALUE.

HVAC, Purge, and Pressurization Units

Some degree of heating and cooling will be required in almost every building, including unoccupied buildings that house only electrical equipment. In addition, controlling dust and moisture is paramount to minimizing electrical problems and maximizing equipment longevity. A 2010 IEEE PCIC paper [4] documented the principal failures of switchgear as mechanical and dielectric breakdowns. The main culprits were temperature, humidity, and contamination.

In addition to maintaining a clean, dry, and temperature-controlled environment, petroleum refineries are continually undergoing upgrades and expansions, and plot space is becoming increasingly important and scarce.



The transformer differential protection.

Since the electrical equipment at the substation distribution level cannot be made with NEMA 7 explosion-proof techniques and cannot be constructed from hermetically sealed or intrinsically safe components, a purge-and-pressurized method for declassification is usually the only means available for placing a distribution substation in or near a classified area.

Beginning with the end in mind, this plant's stakeholders carefully considered hazardous classification boundaries. They reviewed and evaluated the National Fire Protection Agency's *Standard for Purged and Pressurized Enclosures for Electrical Equipment* (NFPA 496) [5], which applies to purging and pressurizing buildings that contain electrical equipment in areas that are designated hazardous in accordance with Article 500 or 505 of NFPA 70 (National Electrical Code) [6].

After carefully assessing the overall refinery plot plan and analyzing the proposed distribution substation locations, it became clear that some degree of forward planning was necessary. Every distribution substation replacement project undergoes a thorough review of existing and potential unit or process expansions during the front-end or definition phase of the project. This determines the degree and extent of a hazardous area boundary, now and in the future. Substations that are going to be located in an existing classified area adhere to NFPA 496. For locations currently unclassified but deemed very likely to be classified in the future, NFPA 496-rated equipment is selected, but the installation may not yet fully comply with the standard.

Regardless of the actual or possible future classification boundary, some simple decisions were made during the standardization development in this plant to prevent major revamps and equipment changes in the future. Some of the more obvious decisions included the requirement that all exterior building lighting and convenience

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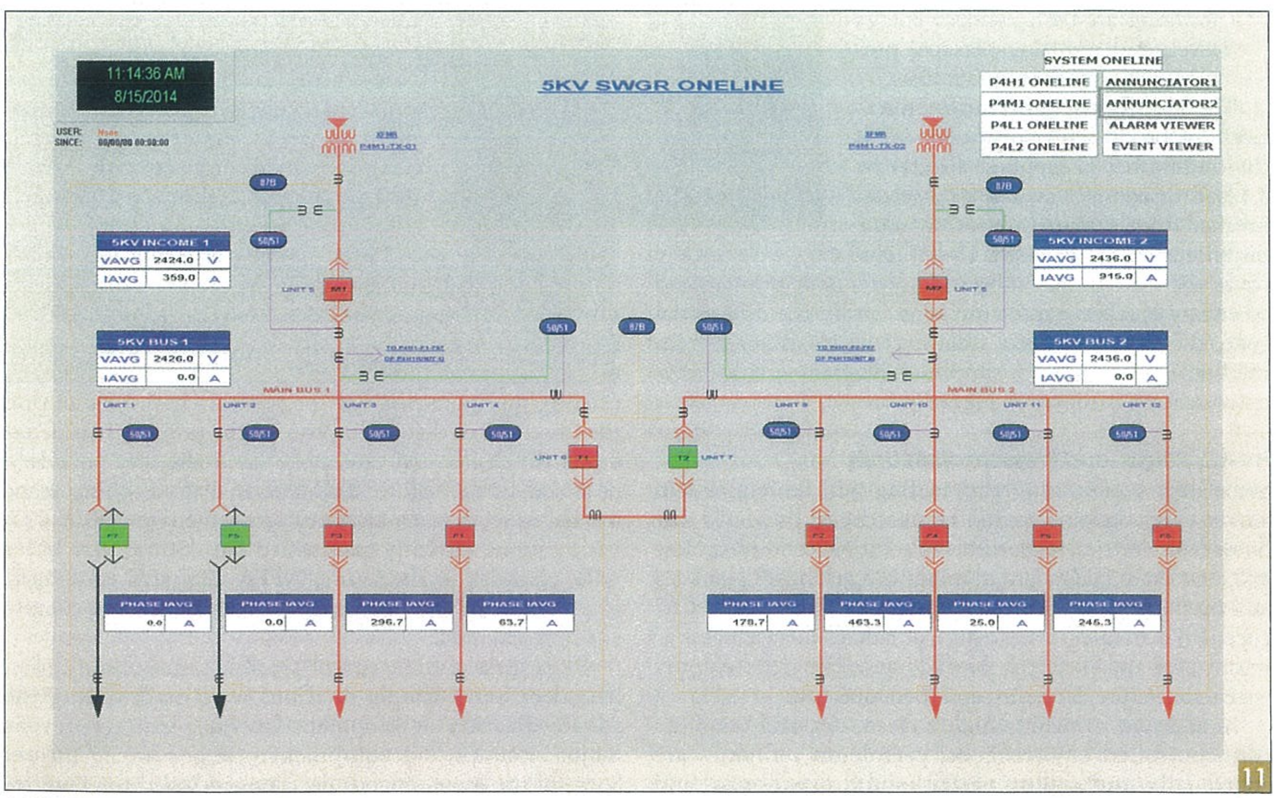
A transformer in a hazardous location. (Used with permission from BP.)

receptacles be manufactured and installed in accordance with a hazardous location classification. These are negligible cost increases and help with warehouse and spare-part inventory, as these are typically the same type of fixtures already selected and installed throughout the plant.

For this particular plant, HVAC and purge and pressurization equipment were to be selected in accordance with NFPA 496 requirements. This was partly motivated by inventory and equipment familiarity. The installed cost for NFPA 496-rated equipment can vary depending primarily on the building size and the extent of implementation. For a single unit that is built to NFPA standards (as opposed to a unit in a general-purpose area), the equipment cost is approximately a 150–200% increase, making the cost for a single unit in the range of US$30,000–US$40,000.

Other items were given more scrutiny on a case-by-case basis, including power distribution transformers and the actual installation of a stack for air intake of the pressurization equipment. For distribution transformers, the primary difference between one manufactured for a general-purpose area and one for a classified area is the control cabinet (which may be general-purpose or explosion-proof rated) and the condulet and wiring methods. During the evaluations, it was found that a transformer constructed for a classified area costs about 10% more than one fabricated for a general-purpose environment.

Like the NFPA 496 analysis, the specific requirement for transformers are carefully evaluated early in the



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A SCADA single-line representation.

Description	Approximate Per-Unit Percentage Cost Increase
Elevated construction versus slab-on-grade construction	35%
Arc-resistant switchgear versus standard switchgear	10%
NFPA purge and pressurization equipment versus standard unit	150–200%
Transformer classified area rated versus standard unit	10%
15-kV switchgear versus primary switch	350%
SCADA versus annunciator	Varies

TABLE 1. A PERCENTAGE COST SUMMARY.

project development prior to final equipment specification. The actual pressurization stack installation is also evaluated. Although the purge and pressurization units were specified and installed pursuant to NFPA 496, any component omitted, such as a stack, can easily be integrated in the future with minimal impact to substation operation or capital cost.

As shown in Figure 5, this particular distribution substation was infringing on a hazardous location and was consequently equipped with a purge and pressurization unit fed from an air source (via the stack) taken outside the classified boundary. Figure 10 shows a transformer for this same substation equipped with a hazardous location-rated control cabinet.

Supervisory Control and Data Acquisition and Control Systems

The majority of existing distribution substations are equipped with simple, window-type annunciator panels. An output from the annunciator drives an exterior rotating beacon and sends a trouble alarm to the plant operations distributed control system. During the standardization process, it became obvious that an annunciator-type alarming system was extremely limiting. Consequently, a fully functional SCADA system is now specified and installed for each distribution substation.

The new SCADA systems provide real-time event-capture data and trending, use single-line graphical representation of the overall substation and individual lineups, and are configured for breaker control. In addition, the alarm annunciator screen is now integrated within the SCADA system and displays critical building, switchgear, and transformer alarm data. Figure 11 depicts a typical single-line representation on a SCADA system.

Like the 15-kV switchgear costs, SCADA system costs depend on the number of items to be monitored and the quantity of information to be captured. In general, costs can range from US$200,000 to US$300,000 for a distribution substation with four switchgear lineups and six transformers.

Stakeholders recently recognized the need to integrate each substation's SCADA system into an overall plant power-management network to bring all distribution substation data to a central server location for remote monitoring and alarm-event analysis. SCADA systems are now being equipped with the network communication necessary to tie in to the ever-expanding plant power-management network.

Conclusion

With aging electrical equipment and a strong emphasis on project drivers such as safety, reliability, and maintainability, many facilities are facing necessary replacements of plant infrastructure systems, including the electrical distribution network. With a good plan and sound decisions regarding standardization, equipment, and construction techniques, long-term real benefit can be achieved.

Many of the options and considerations made by this particular facility were assessed based on the value they brought to the facility and the initial cost for that value. A summary of the key considerations and initial preinvestment values is given in Table 1. The cost was a key element in determining the specific features stakeholders and decision makers deemed valuable and were willing to support. Initial investment can carry a weighted factor that is as large as or larger than any other category, especially when project managers and gatekeepers are involved.

The biggest lesson learned in designing a substation was that, if proper analysis and justifications are made early, they can save time and money later and help ensure that what is done today will fit in well with what is going to be done in the future. This process results in a best practice/best value concept that enhances key drivers and metrics for the facility and all applicable stakeholders.

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