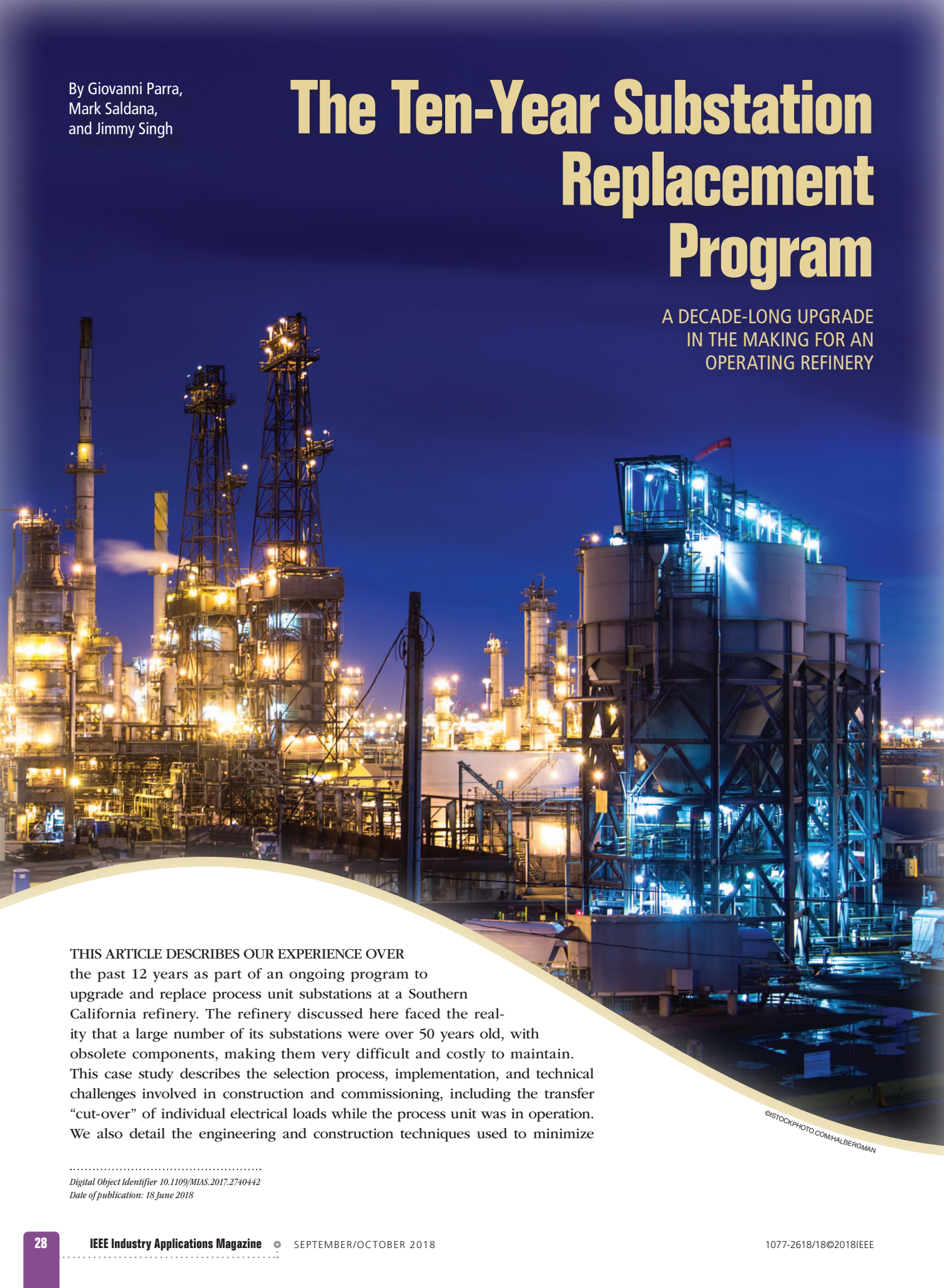


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The Ten-Year Substation Replacement Program

A DECADE-LONG UPGRADE
IN THE MAKING FOR AN
OPERATING REFINERY



THIS ARTICLE DESCRIBES OUR EXPERIENCE OVER the past 12 years as part of an ongoing program to upgrade and replace process unit substations at a Southern California refinery. The refinery discussed here faced the reality that a large number of its substations were over 50 years old, with obsolete components, making them very difficult and costly to maintain. This case study describes the selection process, implementation, and technical challenges involved in construction and commissioning, including the transfer “cut-over” of individual electrical loads while the process unit was in operation. We also detail the engineering and construction techniques used to minimize

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disturbance to the process unit, mitigate risk, and maximize electrical and process unit safety.

The focus here is on process unit substations as opposed to distribution substations. A distribution substation distributes power at a higher voltage to the process unit substation, which reduces the voltage down to the utilization voltages typically employed by process unit electrical loads such as medium- and low-voltage motors, process unit lighting transformers, uninterruptible power supply systems, electric heaters, and so on. Substation design, maintenance, and construction details are not within the scope of this article; however, some examples are provided for illustration.

The refinery was challenged to find an approach and economic justification for replacing individual substations; essentially, these had been a matter of concern only when a failure or adverse incident occurred but lost management's attention once the problem was corrected. After a series of incidents, however, refinery management concluded that a program based on a business strategy for substation replacement and improvements would yield the best results. This article provides insight from the perspective of the owner and the engineering, procurement, and construction contractors charged with implementing the program.

The Ten-Year Plan

In the late 1990s, as a result of the refinery experiencing multiple substation failures over the previous several years, a ten-year plan for substation replacement was developed. The purpose of the plan was to assess each substation and determine when the substation would be at or near its end of life. The assessment included a prioritized list of substations, a projection of when each substation would need to be replaced, the impact to the process unit in the event of failure, and a rough order of magnitude (ROM) estimate of the cost.

A multidisciplinary team was formed to assess the condition of each substation and document problems discovered during the process; this procedure also identified imminent problems and opportunities to replace some of the electrical equipment within a substation or perform corrective maintenance before a substantial failure and power outage occurred. The study of each substation identified electrical loads critical to the process unit, determined intervals between preventive and predictive maintenance, identified spare items or parts to have on site, and provided a schedule of planned outages, all of which aided in the execution of the ten-year plan.

The ten-year substation replacement plan became the document used by project managers when designing the capital and expense budgeting for all refinery projects to be built within the ten-year period. The substation replacement plan also provided risk assessment, justification, and cost information to the refinery's business unit managers, as well as information about the business

impact of a substation identified for replacement because of its unreliability and susceptibility to power outages. This ten-year program led to the establishment of a steady, multiyear level of expenditures to systematically replace substations based on their assessed priority.

Several process unit substations are the same vintage and age but may differ in wear and service. Some substations have switchgear breakers that have experienced extensive cycling in opening and closing, racking in and out, or operating near their design limits; in addition, some were located outdoors and exposed to the weather. Some of the power transformers are in corrosive areas, operate at higher temperatures, or have high levels of dissolved gases. Figures 1 and 2 illustrate extensive wear to electrical equipment.



FIGURE 1. A distribution breaker with burned-out pole insulation. (Photo courtesy of the Tesoro Corporation.)

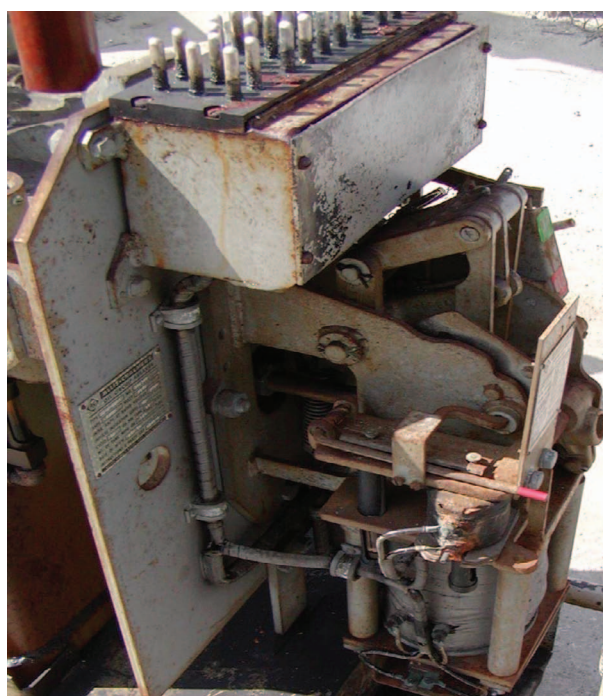


FIGURE 2. A switchgear breaker with worn-out linkages. (Photo courtesy of the Tesoro Corporation.)

Substation Evaluation and Prioritization

A team of refinery personnel was assembled to evaluate and prioritize each substation. The evaluation and prioritization was determined based on the following:

- the health of the equipment and infrastructure
- disruption to the refinery process units from a loss of power
- the level of difficulty in mitigating electrical hazards when performing maintenance
- the reliability of the equipment to function as designed
- the cost impact from the loss of production
- the availability of parts to replace the failed equipment
- the approximate duration of the power outage.

The Assembled Team and Its Contribution to Substation Evaluation and Prioritization

The members of the assembled team and their contributions for the program are described as follows.

- 1) *Refinery process engineer*: The process engineer provided a comprehensive review of the refinery and the interdependency of each process unit. The process engineer also determined the economic, environmental, and safety impacts of a substation power outage resulting from the various process shutdowns within the process unit. In addition, the process engineer provided the unit risk and response needed by operators to bring the process unit and other affected units to a safe condition.
- 2) *Electrical maintenance representative*: The electrical maintenance representative provided information about the overall health of the electrical equipment, such as the condition of the switchgear, circuit breakers, and racking mechanisms; whether the breaker easily jams or gets stuck when racking in or out; and whether personnel are exposed to open buses while racking in breakers.

The electrical maintenance representative informed the team of any reported near misses, such as a breaker falling from inside its cell, failures during testing to open or close by manual controls, or opening by the breaker trip unit. Additionally, the maintenance representative provided a field perspective of the electrical hazards, such as the difficulty of doing work around exposed main buses in the cable termination section and the effort required to put in place extensive safety precautions to do the work. The maintenance representative also supplied information about the health of other electrical equipment such as the power transformers, the extent of tank rust and oil leaks, the results of dissolved

After a series of incidents, however, refinery management concluded that a program based on a business strategy for substation replacement and improvements would yield the best results.

gas analysis (DGA), and other test results that may indicate age and suitability for prolonged service. Other important information included the availability of spare parts, manufacturer support, and the willingness of operations to place process equipment offline for substation electrical maintenance.

- 3) *Electrical engineer*: The electrical engineer determined the overall health of the electrical equipment using information provided by the maintenance representative along with a comprehensive review of the electrical system load flow, short circuit rating, and equipment withstand ratings. The electrical engineer also reviewed all available equipment test reports,

such as tests on circuit breakers, cables, and transformers' DGA, as well as other test results from partial discharge and infrared scans, including an arc-flash incident energy evaluation.

The electrical engineer evaluated the protection scheme and protection levels of fault clearing equipment; determined the extent of the outage if a protective device failed to open and an upstream protective device operated to clear the fault; consulted with equipment manufacturers for any recalls, advisories, or usage warnings that have been issued; and determined manufacturing and replacement delivery timelines for failed equipment. The electrical engineer also provided the critical knowledge to adequately assess the likelihood and potential duration of outages due to an electrical fault.

- 4) *Project engineer*: The project engineer provided the execution plan for each substation and assessed the infrastructure upgrades needed for the replacement substation. This assessment included determining plot space availability, advice concerning whether existing pipe-ways and conduit structures could accept additional loading or whether new structures needed to be built, development of a construction contracting strategy, and detailing the need for crane lifts over operating units that required special risk mitigation along with other installation challenges.

The project engineer incorporated the site environmental, health, and safety issues into the plan and included any special circumstance that had to be accounted for in developing an accurate project cost and the duration needed to execute the project. The project engineer coordinated with operations and determined when process unit turnaround (TAR) and routine maintenance schedules occurred, along with other opportunities for cut-over of existing electrical loads.

Consequence-Versus-Probability Matrices

The consequence-versus-probability matrix is a risk-assessment document provided by a company's risk-management division to use when comparing each risk with other risks and so determine which has a greater priority. This type of risk assessment is a common practice used by many corporations, providing a way to determine where a greater amount of effort to mitigate an occurrence should be applied. The probability is the likelihood that the risk will occur and the consequence is the measure of how greatly the occurrence will affect the business unit. The numbers in the matrix boxes are weighted subjectively and designed to appropriately produce prediction concerning which occurrences pose the greater risk. The weighted numbers increase as the risk to safety, health, or lost profit increases based on an event versus the probability that it occurs (such as the loss of power from an unreliable substation).

Substation Assessment

The tools used to evaluate the risk and priority of each substation consisted of consequence-versus-probability matrices for plant capacity and maintenance, health and safety, and other potential hazards. These plots provided a quantitative relationship among the risks and enabled the team to develop a ranking of each substation's priority for upgrade or replacement. All the matrices used the following ranking system:

- 1) *Vertical axis*: The vertical axis is alphabetized A–E, with E representing the most serious consequence.
- 2) *Horizontal axis*: The horizontal axis is numbered 1–5, with 5 representing the highest probability.
 - “Rarely” indicates that a similar event has not yet occurred and has a remote possibility.
 - “Unlikely” indicates that a similar event has not yet occurred.
 - “Possible” indicates that a similar event has occurred.
 - “Probable” indicates that a similar event has occurred or is likely to occur.
 - “Very likely” indicates that the event is likely to occur once or twice within the next ten years.

The plant safe-work practices and ability to do routine maintenance were considered when assigning probability of occurrence.

- 3) *The ranking score*: Each matrix provided a rank number. The sum of the resulting value of each matrix indicated the ranking of each substation priority used to select the order of upgrade or replacement [see Table 1 under the priority (Pri) ranking column]. The higher the ranking number, the higher the priority and the order of substation replacement.

For each substation, the assessment team prepared three matrix models to rank and establish the substation's priority in the ten-year plan. The three matrix categories were: 1) plant capacity and maintenance (see Table 2), which evaluates the

consequence and probability associated with lost revenue, ranked A–E, as explained earlier; 2) personnel health and safety (see Table 3), which evaluates the consequence and probability associated with the health and safety of maintenance personnel when working on or operating the electrical equipment associated with the substation; and 3) other potential hazards (see Table 4), which include the consequence and probability associated with other potential hazards such as the equipment manufacturer's advisories to avoid continued use of the equipment, hazards associated with the substation's physical location, and the availability of equipment to perform maintenance that may adversely affect the equipment's reliable performance as designed.

The criteria used to populate the consequence and probability matrices included

- 1) predictive maintenance
 - the results from cable and partial discharge testing
 - the results from the transformer DGA.
- 2) preventative maintenance intervals
 - inspection of breakers including oil-insulated breakers
 - maintenance adjustments to breaker opening times
 - transformer inspections (e.g., oil leaks, rust, or operating temperature)
 - outdoor bus inspections (e.g., rust, enclosure cracks, or evidence of water intrusion)
 - inspection of switchgear, protective relays, and metering.
- 3) risk of performing maintenance
 - exposed bus and feeder cables in the same compartment
 - breaker cells with exposed barriers or no shutters to protect workers
 - feeder breakers requiring frequent maintenance to ensure reliability.
- 4) safety to operations, substation shock, and arc-flash hazard
 - a history of near misses, placing electricians in risky situations (i.e., the line of fire)
 - working in close proximity to an exposed energized bus when replacing or installing cable
 - arc-flash energy calculated above the personnel protective equipment protective rating.
- 5) consequences of loss of power on process units
 - process units with high-risk loads (e.g., critical motor-driven pumps or compressors)
 - redundant or back-up motor-driven pumps or compressors on the same power source
 - single-point failure impacting more than one process unit
 - the number of days, weeks, or months to repair or replace failed equipment
 - the revenue lost due to prolonged power outages.

Table 1. The substations' evaluation and resolution priorities as of year-end 2014

Points	Priority	TAR (Yes/ No)	Status	Project Title	Evaluation	Resolution
37	1	No	In progress; complete in 2016	Substation 1E Transformer Replace	Transformers are trending toward their end of life. Oil analysis indicates thermal aging and high moisture content from degrading insulation paper.	Replace Substation 66/12.47-kV power transformers.
30	2	Yes	In progress; complete in 2015	Substation 40A Upgrade	For Substation 40A, a 480-V system upgrade is provided as part of the distributed control system upgrade. The 480-V system is radial and susceptible to single-point failures that would impact both coker units.	Replace Substation 40A's two 480-V radial systems with one double-ended system with an auto-transfer on the tie breaker.
34	3	Yes	Start project in 2016	Substation 41 Replace	Substation 41 is difficult to maintain because there are two process units that both need to be shut down at the same time, which is not aligned with the business strategy. Lack of maintenance is an ongoing issue. Substation 41 is near process equipment and, therefore, does not meet refinery standards.	Replace Substation 41 with a power distribution center (PDC) that has two motor-control centers (MCCs): two incoming power sources fed from Substation 1H, one for each MCC. Separate the two process units' motor loads so that maintenance can occur as each process unit is shut down for TAR.
32	4	Yes	Start project in 2017	Substation 30 Replace	Oil case circuit breakers are obsolete. The short circuit duty is marginal. Breakers often jam when racking breakers in and out, requiring unplanned outages.	Replace Substation 30. Install a PDC that is a double-ended 12–2.4-kV substation. Incoming power sources are fed from Substation 35.
29	5	Yes	Start project in 2018	Substation 40 Replace	Substation 40 is a radial 480-V and 2.4-kV system susceptible to single-point failures. The isolation disconnect is by a 12-kV disconnect oil switch with six poles, including two incoming sources with one pole configured as a tie. The manufacturer advises usage of the oil switch to be discontinued. All voltage level systems are difficult to maintain.	Replace Substation 40. Install a PDC that is double-ended with 12-kV and 480-V switchgear. Install two low- and medium-voltage MCCs. Incoming power sources are fed from Substation 1D. Separate the process loads so that the main and backup motor-driven pumps are from two separate MCCs.
29	6	No	Start project in 2018	Substation 27 Retire	Low-voltage switchgear breakers are obsolete and difficult to maintain. A 480-V main horizontal bus is open and located in the cable feeder section.	Retire Substation 27 by refeeding its loads from Substation 52. Add two MCCs, and locate them inside an existing switch-room shelter.
27	7	Yes	Start project in 2017	Substation 1C Replace	Substation 1C is critical to multiple process units. It is radial fed, and a single failure would have a significant impact.	Replace Substation 1C with double-ended 12-kV, 2.4-kV, and 480-V systems. The new substation would be fed out of Substation 1M.
21	8	Yes	Start project in 2019	Number 2 Reformer Switchroom Replace	Circuit breakers and parts are from salvaged supply companies. The 480-V main horizontal bus is not separated from the cable compartment, thereby placing personnel at risk when replacing cables.	Replace with a PDC that has two MCCs. Two incoming power sources are fed from Substation 82, one for each MCC.

(continued)

Table 1. The substations' evaluation and resolution priorities as of year-end 2014 (continued)

Points	Priority	TAR (Yes/ No)	Status	Project Title	Evaluation	Resolution
19	9	No	Start project in 2016	Substation 36 Retire	The 480-V switchgear breakers require continuous maintenance. The main horizontal bus is open and located in the cable feeder section. The main bus is close to the outgoing feeder cables and requires deenergizing or temporary barriers when replacing cables.	Retire Substation 36 by refeeding its loads from the new PDC MCC that replaced Substation 14. The new PDC MCC was designed with the capacity and infrastructure for Substation 36 loads.
19	10	Yes	Start project in 2020	Substation 33 Replace	The circuit breakers are obsolete. The circuit breakers and parts are from salvaged supply companies.	Replace Substation 33. Install a PDC with two MCCs fed out of Substation 1J.

A typical result of a risk assessment for several substations by a team that understands the risks from multiple views of operating a refinery.

Table 2. The plant capacity and maintenance matrix for Substation 25

<u>Consequence</u>		<u>Probability of Occurrence</u>				
E	Multiple unit shutdown; loss of supply to consumers; prolonged major unit shutdown (more than three days)	11	16	20	25	30
D	Major unit shutdown; extended unit slowdown; major unplanned changes to product export	8	10	15	19	24
C	Major unit slowdown	6	8	12	14	18
B	Minor unit slowdown; yield loss; significant short-term drain on operational resources	4	5	7	12	13
A	Measurable energy loss	1	2	3	4	12
		1	2	3	4	5
		Rarely	Unlikely	Possible	Probable	Very Likely

Table 3. The personnel health and safety matrix for Substation 25

<u>Consequence</u>		<u>Probability of Occurrence</u>				
E	Very major health and safety incident	11	16	20	25	30
D	Major impact to health and safety incident	8	10	15	19	24
C	High impact to health and safety incident	6	8	12	14	18
B	Medium impact to health and safety incident	4	5	7	12	13
A	Low impact to health and safety incident	1	2	3	4	12
		1	2	3	4	5
		Rarely	Unlikely	Possible	Probable	Very Likely

Table 4. Other potential hazards matrix for Substation 25

<u>Consequence</u>		<u>Probability of Occurrence</u>				
E	The equipment manufacturer advised discontinuing usage because of injury occurrences. The equipment is in a hostile environment and will eventually fail.	11	16	20	25	30
D	The equipment manufacturer recommended replacement. The equipment is in a hostile environment and cannot be mitigated.	8	10	15	19	24
C	The equipment cannot be maintained because of availability, repeated repairs, or worn-out alignment inside cells. The manufacturer does not support the equipment.	6	8	12	14	18
B	The equipment is difficult to remove from service for maintenance because of impacts to the process unit.	4	5	7	12	13
A	The equipment's spare parts are difficult to obtain. The equipment requires frequent corrective maintenance.	1	2	3	4	12
		1	2	3	4	5
		Rarely	Unlikely	Possible	Probable	Very Likely

6) maintainability

- the functional condition of the switchgear racking gear mechanism and its ability to properly operate the breakers
- the breakers' history of jamming, falling off their rails, or creating burned connections
- the breakers repeatedly failing to open or clear a fault
- the breakers failing to open or close because of improper cell switch alignment
- the equipment being beyond its expected useful life
- no available replacement parts.

7) substation enclosures

- the substation enclosure is rusted, has holes in its roof, or shows evidence of entry of water or dust.

8) manufacturer advisories

- notice from the original equipment manufacturer (OEM) advising discontinued use of this equipment
- recalls
- modifications or upgrades.

9) manufacturer technical support

- the equipment is no longer supported by the OEM
- spare parts are no longer available from the OEM
- the OEM is no longer in business.

The composite ranking of each substation obtained from the consequence-versus-probability matrices is compiled into the refinery substation assessment spreadsheet (a reduced version is shown in Table 5). The spreadsheet provided information to the refinery management in a single document and included the order of priority, the substation project title, the equipment's age, and a brief description of the consequences of equipment failure, how difficult it was to restore power, the affected process unit loads, and a replacement plan. The plan should align with the refinery TAR schedule and, consequently, may shift the order of execution.

Project Execution

A typical project process consists of front-end loading (FEL), project definition, and project execution. FEL1 occurs when the economic viability is established, FEL2 when the options are selected, and FEL3 when the project is defined with sufficient accuracy to support a funding estimate.

During FEL, the owner and engineer work to identify and justify the project. Early in FEL1, the project team concluded that it was very difficult to perform economic justification for each individual substation because the direct cost of maintaining the substation is small compared to the replacement cost. Refinery management decided that the best approach to justify substation replacement would be to handle it as a program and evaluate the risk to production loss and personnel hazards associated with each aging substation.

Members of engineering, maintenance, and operations participated in risk-assessment sessions, where they identified possible failure scenarios based on the condition of each substation and the effect of the failures on either personnel or operating units. Consequence-versus-probability plots were developed for each substation to establish the replacement priority and project development sequence. Once the sequence was established, factored ROM estimates were developed for each substation, and an annual spending plan was put in place to replace substations sequentially at a rate of one per year.

A project starts in FEL2, when a substation comes up for replacement, during which the technical and site location options and their associated cost, schedule, and resource needs are evaluated and a final option chosen. During this stage, the engineering companies, construction companies, and suppliers are selected. The schedule is evaluated to determine whether the project is driven

Table 5. The results of the ten-year substation replacement plan as of year-end 2014

Points	Priority	Status	Project Title	Evaluation	Resolution
35	1	Completed 2004	Number 1 Reformer MCC Replace	Switchroom medium-voltage motor starters are nonfused and oil immersed. The short circuit duty is marginal. Spare parts for the motor contactor are extremely difficult to find or do not exist.	Replace the 2.4-kV MCC with two MCCs: one MCC for the main motor pump and the second MCC for the backup motor pumps. Locate both MCCs inside Substation 1J.
34	2	Completed 2005	Substation 21 Retire	The incoming feeder is a 50-year-old lead cable. Isolation is a fused-oil switch that the manufacturer advises to discontinue using. The transformer's high-voltage connections are exposed, and the insulation has visible signs of aging.	Retire Substation 21 by refeeding its loads from other existing substations.
33	3	Completed 2008	Substation 38 and Crude Switchroom Replace	Substation 38 and the crude MCC's incoming power source are from a single feeder, and a failure of either would cause a shutdown of multiple crude units. The Substation 38 isolation is a fused-oil switch that the manufacturer advises to discontinue using.	Replace Substation 38 and crude battery MCCs. Install two low- and medium-voltage MCCs. Add four incoming power sources fed from the double-ended Substation 7, one for each MCC. Separate the process loads.
32	4	Completed 2004	Administrative and Engineering Building Remove Oil Switch	The isolation is a fused-oil switch that the manufacturer advises to discontinue using.	Remove the oil switch. Isolation will be performed by the upstream feeder breaker.
38	5	Completed 2011	Substation 26 Replace	The substation switchgear is severely worn out. Circuit breakers are oil filled and oil leaks are common. The megavolt-ampere (MVA) short circuit rating of the equipment is marginal. The breaker cubicle cell structure mechanical guides and gears are worn and often cause breakers to jam.	Replace Substation 26. Install a double-ended 12–0.48-kV substation. Install two low- and medium-voltage MCCs. Feed incoming power sources from Substation 1J (bus A and B sources). Separate the process loads for the main and backup motor-driven pumps.
38	6	Completed 2012	Substation 25 Replace	Low-voltage motor starters are switchgear breakers and require continuous maintenance. Circuit breakers jam, and linkage adjustments are continuous. The 480-V main horizontal bus is open and located in the cable feeder section. The main bus is very close to the outgoing breaker.	Replace Substation 25. Install a double-ended 12–0.48-kV substation fed from Substation 75. Install four low-voltage MCCs. Divide the cooling tower motor-driven fans onto the four MCCs for easier maintenance on switchgear and motor control.
33	7	Completed 2013	Substation 14 Replace	The 480-V switchgear breakers are obsolete and require continuous maintenance. The main bus is open and located in the cable feeder section. The main bus requires deenergizing or temporary barriers when replacing the cable.	Replace with a PDC with two MCCs. Two Incoming power sources are fed from Substation 81, one for each MCC. Separate the process loads so that redundant motor drivers are from two separate MCCs. The PDC is sized with enough capacity to replace Substation 36.
33	8	Completed 2014	Substation 24 Retire	Oil-case circuit breakers are obsolete. The short circuit duty is marginal. Breakers jam when racking breakers in and out, requiring unplanned outages. Breakers have shown severe evidence of burns on the insulation.	Retire Substation 24 by refeeding its loads from other existing substations.

The success of the ten-year plan by listing the substations that were either replaced or had risks that were mitigated to an acceptable tolerance. The success of the program heavily depends on the acceptance of the ten-year substation replacement plan by upper management.

by a TAR date, cash flow, or the substation's condition. The specifications to be used are developed and frozen in FEL2, and decisions about whether the substation's location and building materials (i.e., whether it will be prefabricated or stick-built) are made. These details are established so that a proper estimate and construction plan can be developed.

The next phase of the project is FEL3, during which the selected option is developed in detail for a funding estimate. For accuracy, everything must be identified and included in the estimate during this stage. A thorough assessment of the conduit routings and available supporting steel must be conducted, taking into account the condition of existing pipe racks. For instance, assumptions that rack space could be used had to be confirmed with

the site structural engineer, as many of the old pipe racks in the refinery were built to older codes and even a minor addition could trigger a major upgrade of the pipe rack to the current codes at very high cost.

A risk analysis was conducted with plant operations to identify whether it was necessary to single-end the substation to perform a cut-over of process loads and to use substation supports in multiple operating units; the analysis also determined if there may be any secondary impacts or required auxiliary power to mitigate a potential outage. All these costs must be included in the scope of the estimate.

During the execute/construction phase, the equipment is procured, contracts are awarded, procedures developed, and the substation enters into construction. Finally, during the commissioning and startup phase, the tie-ins, cut-over of loads, and energization occur.

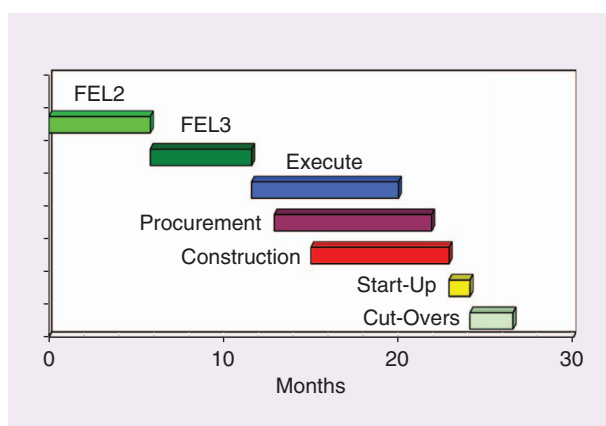


FIGURE 3. A typical project schedule.

Schedule

As part of the ten-year plan, an overall completion plan was prepared for each substation. During the different execution phases of the project, a detailed schedule was prepared that included work planned around unit TAR and process equipment maintenance.

The typical schedule duration for a substation replacement is approximately two years. The plan allowed for several substations to be staggered such that the same engineering and construction team would do most of the substations. Engineering personnel would develop the next substation while the current substation was being constructed. The annual spending allocation allowed

Rank Points	Substation	Equipment Age at Year 2012	Ten-Year Plan										Scope
			1	2	3	4	5	6	7	8	9	10	
33	14	60	→										Replacement
33	24	58	→	→									Retirement
37	1E XFMR	33		→	→								Replacement
30	40A	30		→	→								Expansion
34	41	46				→	→						Replacement
32	30	55					→	→					Replacement
29	40	46						→	→				Replacement
29	27	60							→	→			Retirement
27	1C	44					→	→					Replacement
21	Number 2 Reformer Switch Room	50							→	→			Replacement
19	36	49					→	→					Retirement
19	33	50								→	→		Replacement

FIGURE 4. The overall program.

approximately one substation to be completed each year (Figures 3 and 4).

Cost Estimates

Detailed estimates were prepared at each stage of the project; these included direct, indirect, and commissioning costs (Figures 5 and 6). An analysis of the total installed cost as compared with other refinery process projects revealed that the cost of the raceways needed to refeed the process loads was significant. In addition, cut-over cost and backup power or mechanical systems to mitigate trips, either to keep the unit operational or minimize the downtime during the cut-over, were significant. Other costs that had an impact included demolition, training maintenance personnel on new equipment, and training operation personnel in management of change.

Refinery History and Background

The refinery has been in operation since 1923, and the original main distribution voltage was 12.47 kV. Today, the refinery's average power demand is 70 MW, supplied by a 420-MW cogeneration facility. The cogeneration facility interconnects to the local utility via two 230-kV transmission lines and supplies power to the refinery main substations at 66 and 13.8 kV.

The distribution voltage to the process unit substation is 12.47 kV, and the utilization voltages for process unit loads are 4.16 kV, 2.4 kV, and 480 V. Over the 90 years that the refinery has been in operation, several substations have been retired, replaced, or upgraded, and the distribution network has changed several times to support refinery expansion and reconfiguration.

In 2013, the refinery was expanded to include a second site logistically located within a few miles, with the goal of merging the two refineries to operate as one plant. This process was used to prioritize the second site substations, where seven substations are being evaluated for replacement.

Engineering

The plan indicated in Figure 4 shows that six substations are between 44 and 50 years old and four are between 51 and 60 years old. Several are either single-ended or lack an automatic transfer scheme and are loaded up to near capacity. The latest plan identified six of these substations to be replaced within the next ten years.

The project standardized the substation design as double-ended with an automatic transfer scheme and enough capacity to address planned future loads and spare capacity. The substation design included the latest technology of arc-flash-resistant and/or arc-flash-preventive equipment and remote racking to achieve a higher level of reliability and safety for personnel.

Switching and cut-over procedures were written to ensure safe work practices and achieve a controlled transfer of loads onto the new or existing substations with minimum disturbance to operating process units.

Design Challenges During Execution

Replacing a Radial Substation

The existing radial substations provided power to the main and spare process equipment such as motor driven pumps. A loss of power from the one common power source made the process units susceptible to a shutdown.

The replacement substations are double-ended. This provided redundant or alternate power sources for the main and spare electrical loads. The process unit operators

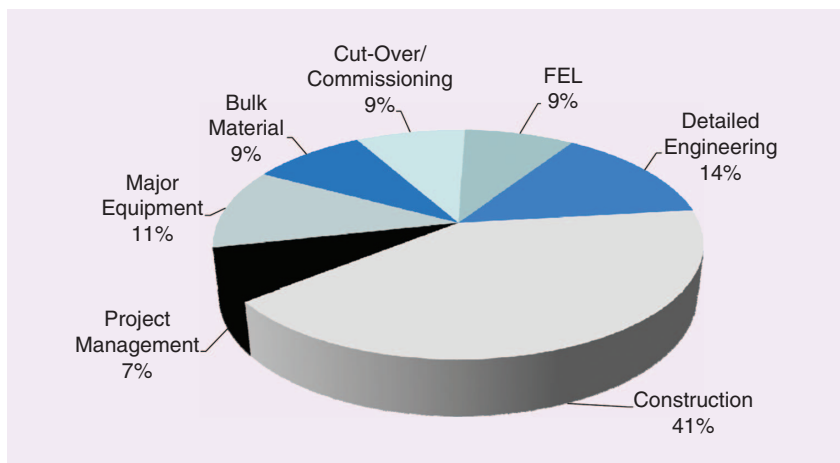


FIGURE 5. The cost of a typical project.

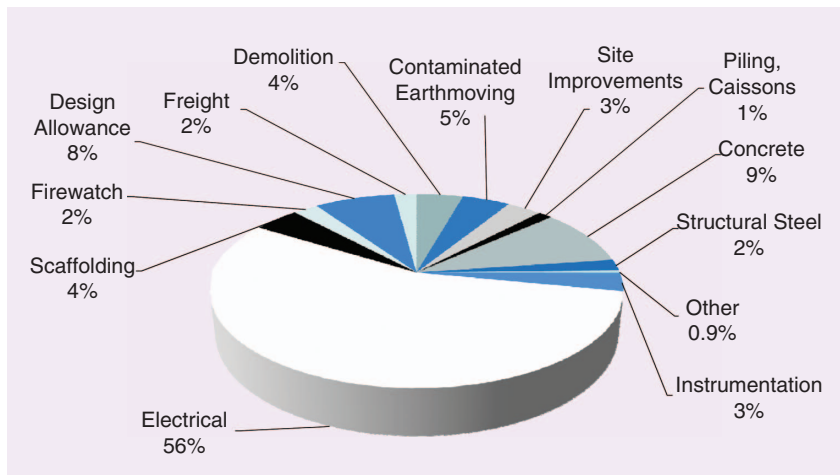


FIGURE 6. Substation replacement direct costs.

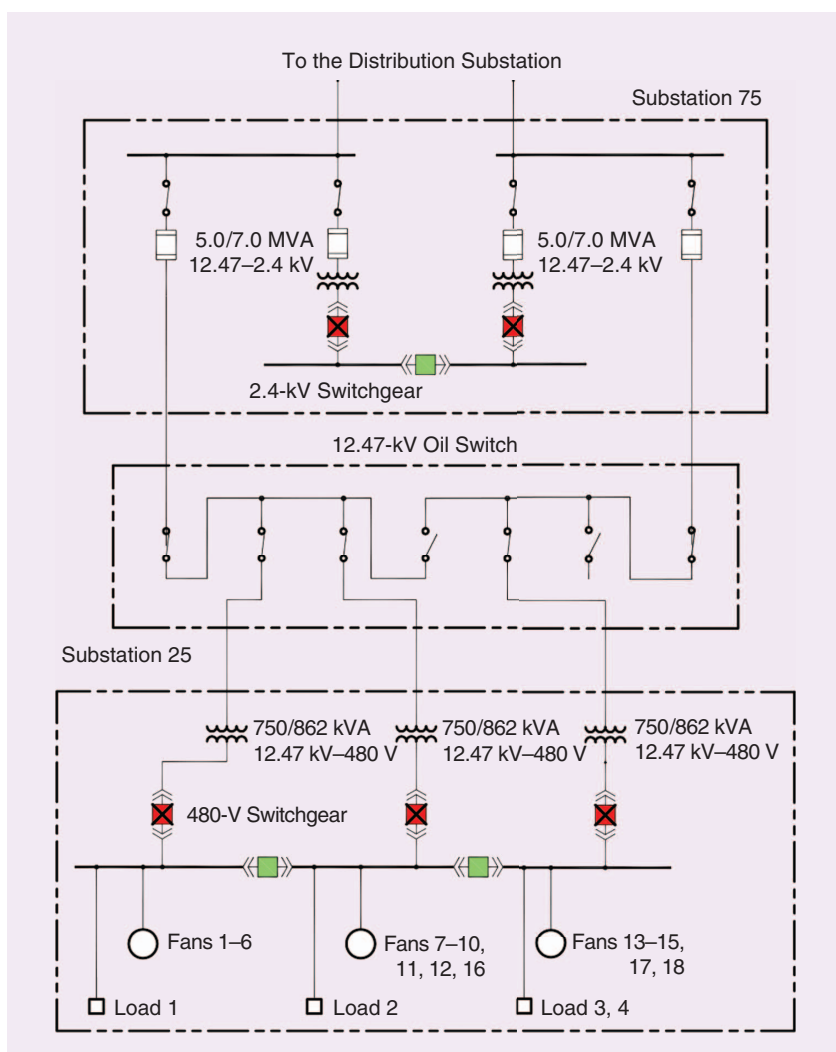


FIGURE 7. The original substation configuration.

and process engineers evaluated each process unit's electrical loads and provided an optimum reliability plan to the electrical design engineer. This plan included separating the main and spare electrical loads onto alternate power sources and selecting which power source to use for connecting nonredundant process loads based on its impact on other process units either up- or downstream.

Process Unit Operating Requirements

Process unit operators and process engineers identified electrical loads that were critical to operating the unit; these loads required special consideration and written procedures detailing how the cut-over of each load must be accomplished. The procedure identified individual roles and responsibilities involved in the cut-over, listed operating windows of equipment availability, and clarified whether temporary power was required to keep critical equipment in operation during the cut-over process. Recovery plans were developed to provide guidance in the event that something did not go according to plan and

critical equipment was unintentionally shutdown. Operations assigned a single contact point for the project to coordinate activities within the process unit, provide advice on how long the unit could tolerate having a section of process equipment out of service without disrupting production, and determine its impact on the process unit should the cut-over take longer than planned.

The goal was to execute the project with the process unit operating; however, some tie-ins could be accessed only during a unit shutdown. During planning, the team compared the substations replacement schedule with the TAR schedule to identify these connections and align their execution with any unit TAR that would occur before the project was scheduled for execution. Examples of these tasks included deenergizing a 2.4-kV switchgear bus to modify and install relay protection schemes into the switchgear cubicle; deenergizing and relocating medium-voltage cable inside an electrical manhole to prepare the manhole for future cables; and deenergizing a 480-V MCC and installing a feeder or motor starter bucket. Recognizing these opportunities early identified the need for special funding to perform these tie-ins before full project funding.

Figures 7 and 8 show simplified, one-line before-and-after diagrams of the electrical distribution for a large cooling tower that provides cooled water to multiple process units. In Figure 7, two 12.47-kV incoming feeders are connected to a seven-pole, oil-filled load break switch with a common tie. The 480-V switchgear had three main breakers, two tie breakers, and feeder breakers. All breakers were manually operated with no automatic transfer scheme. The 480-V loads were cooling tower fans and other miscellaneous loads. The 12.47-kV oil-filled load break switch, oil-filled transformers, and 480-V switchgear were replaced. Figure 8 shows the final configuration, taking into consideration all aspects of operation, maintenance, and reliability. The loads are now connected to a double-ended 480-V arc-resistant switchgear with an automatic transfer scheme.

Process Units Future Loads, Modifications, or Enhancements
The affected process units were evaluated to determine the probability of upcoming process changes that would require new electrical loads in the foreseeable future. This

was taken into account to determine whether extra capacity would be needed in the new substation. The ability to add spare capacity was evaluated against the budget, and discussions were held with the team to make the decision to either add capital or forego the expansion. In some instances when the cost was manageable, capacity was added; however, in several cases, the scope was frozen, and it was decided that a future project would have to address the extra capacity.

Identifying Hidden Loads

It became apparent during the first substation project that these old process unit substations did not have all electrical loads accurately documented or archived in a database. A significant number of hidden loads were 240 V and lower. Many 240/208/120-V panel load descriptions were not accurate; in some instances, process instrumentation power was not shown, and area lighting was not completely understood. The team made it a requirement of each project that process unit walk-downs be performed during FEL2 and FEL3 to compare the drawings with the physical installation and discover the actual field condition as much as possible. Existing enclosures and relay control panels thought to be out of service were actually in service or partially so. The project team made an effort to identify as many electrical loads as possible to minimize the risk or delays when cut-over of loads were being performed and to accurately assess the job to ensure the estimate reflected its true scope.

Process Unit Control Systems

Process control systems were identified from unit process and instrument diagrams and determined by test records and unit walk-downs at the last time the process system was tested. Some control systems may go untested because they are not documented or understood by operations. Operations and the instrument control engineer evaluated these types of systems and provided a recommendation on whether the system should be tested prior to cut-over. Testing prior to cut-over provided “as-found” conditions. Discrepancies or failures uncovered during testing were corrected by routine maintenance. This increased confidence that the control system would function correctly after the cut-over was completed. The project team had more control of the project scope and costs. Cutting-over

the control system without testing first could lead to doubt that the cut-over was performed correctly. In other words, the cut-over team would be held responsible for leaving a system inoperable because of preexisting conditions.

Maintainability of Equipment, Safety, and Reliability

For each substation replacement project, design and maintainability reviews were conducted with the site maintenance electricians and the electrical engineer to ensure that all electrical equipment, such as MCCs, transformers, feeder breakers, and main breakers, could be isolated for maintenance. Multiple process units being fed from a single common MCC or switchgear breaker was avoided so that maintenance planning was not dependent on multiple process unit shutdowns to deenergize electrical equipment to perform maintenance.

The reviews included identifying maintenance opportunities to deenergize electrical equipment with the process unit operating, during a major TAR, and during partial unit shutdown. The project team consulted with the process volumetric group, which evaluates and schedules which process units operate or shut down based on refinery production, to ensure that these electrical loads would be logically connected to the various substations that coincide with process unit shutdown schedules.

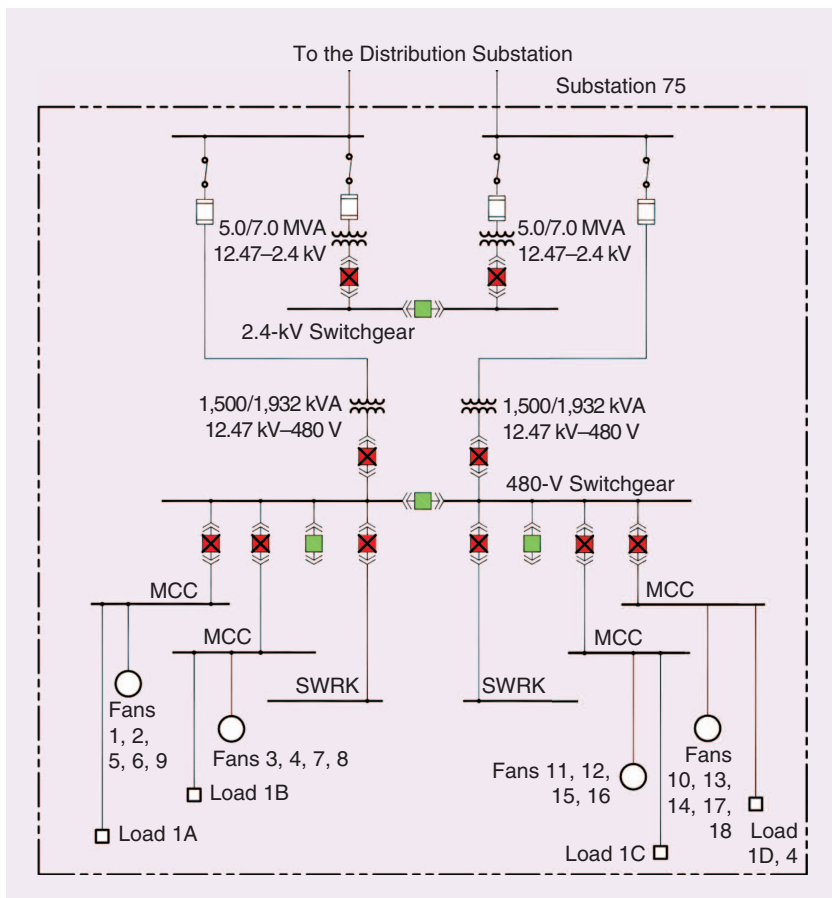


FIGURE 8. The new substation configuration. SWRK: switchrack.

Existing MCCs, Outdoor Switch Racks, and Process Control

Existing downstream electrical equipment was evaluated for capacity, short circuit, and physical condition to determine the suitability of connecting the equipment to the new substation. If the existing equipment did not meet the new short circuit rating or capacity or was not suitable for reconnection, then it was replaced and included in the scope of work with the new substation.

Using Existing Electrical Underground Infrastructure

The project evaluated the conditions and availability of the existing underground conduit, manholes, and substation vaults to maximize the use of existing infrastructure. The project prepared cable derating and ampacity calculations to confirm that the cables did not exceed their maximum operating temperature. The use of existing spare conduits was not possible in some cases due to duct bank overheating or to cable congestion in a manhole. Aboveground raceways were installed when underground infrastructure was not available.

The New Substation's Location

To meet the refinery's process unit equipment spacing guidelines where there was limited plot space, multiple location studies were required. These studies were conducted during FEL2. In some cases, the options were limited, and the best was to locate the substation inside a Class I, Division 2 hazardous classified area. In this situation, the new substation was pressurized in compliance with National Fire Prevention Association 496, Chapter 7 requirements [1]. Hydrogen sulfide (H₂S) and hydrocarbon gas monitoring systems were included and integrated with the fire detection and pressurization or heating, ventilation, and air conditioning system.

Codes and Permitting

The County of Los Angeles, where this site is located, has specific requirements and regulations. Additionally, the city fire department and other environmental agencies have jurisdiction, which makes the process of obtaining plan check approval very detailed and lengthy. To manage this process, special consideration was made in the project engineering cycle and schedule to include every activity associated with permits. In many instances, old equipment being connected to the new substations had to be brought up to code, as the latest state, county, and city codes do not grandfather old installations when tied to new installations. This required vigilance on the part of the project team to

This ten-year program led to the establishment of a steady, multiyear level of expenditures to systematically replace substations based on their assessed priority.

identify this issue during FEL and include it in the scope of the work.

Constructability

Working around operating process units presented a level of execution difficulty (i.e., hot work permits). In particular, due to recent industrial accidents, the refinery expanded the "control of work process" to include a task risk assessment and scope-of-work identification prior to issuing permits; this included engineering investigation within the units.

The impact of these requirements had to be understood and incorporated into the project schedule. For instance, before an engineer or designer could go to the unit with

maintenance to open electrical equipment for inspection and verification of the as-built condition, he or she would have to schedule the task several weeks in advance. Ignoring these conditions would put the project at risk for schedule delays and, if an inspection was foregone because it had not been properly scheduled, put the project at risk of having an unidentified scope and the associated hidden costs.

Field labor efficiency became an objective of the project. Therefore, modularization and prefabricated components were specified. With the exception of a few cases, prefabricated substations, packaged MCCs, or modules were selected to reduce field construction and accelerate the commissioning phase by taking advantage of factory checkouts and precommissioning. This proved more cost-effective than stick-built construction due to the factory's higher productivity factor.

Retrofitting Existing Facilities

The addition of a new substation sometimes required the installation of new feeders or retrofitting or adding equipment in the existing distribution substation switchgear. These additions included new relaying, transfer trip devices, power breakers, and other protective devices. Installing new devices into existing equipment required the equipment to be deenergized. During FEL3, the number of detailed switching procedures required for working on the equipment was identified and included in the scope of the work.

Construction Challenges

The construction team had to deal with a number of issues, some of them unusual, with schedule and cost impacts.

Environmental

Some environmental challenges are described as follows.

- 1) The project expected to find soils contaminated with asbestos, volatile organic compounds, or H₂S based

on the refinery's history and plot location. In some locations, the soils had a combination of all three contaminants or contaminant levels that significantly exceeded state guidelines, which required specialized handling and disposal, including disposal to out-of-state facilities. Abatement costs can be significant to the overall project cost.

- 2) Lead-based paint had to be removed to weld new raceway supports on existing pipe racks. This type of paint was used throughout the refinery before the 1978 ban. Handling and disposal of the paint had to meet California's Division of Occupational Safety and Health (Cal/OSHA) and federal requirements.
- 3) Disposing of old electrical equipment, with components containing asbestos or mercury, required special handling.
- 4) Paper-insulated lead-sheath cables required special handling and removal.
- 5) Oil-insulated circuit breakers, switches, capacitors, and transformers were tested for polychlorinated biphenyls to determine appropriate handling and disposal.

Handling of the above contaminants was performed in accordance with Cal/OSHA, U.S. Environmental Protection Agency, and other federal regulations using certified personnel or contractors.

Logistics

The transportation logistics group was engaged before funding to define routing plans, identify obstructions, and plan rigging.

Working In or Around TAR

Performing work during a TAR has benefits and also challenges. The benefits include working with deenergized equipment, which is a great opportunity to accelerate the cut-over process. Challenges include getting acceptance to add work to a TAR, which typically has a full work schedule and a constrained timeline, and working among multiple crews not related to the project activities.

Commissioning and Startup

The commissioning and startup (energization) of new substation auxiliary systems and electrical equipment follows the traditional inspections, testing, and assurances that would be performed on a new substation. The key difference was that, at the end of the construction phase, the substation was commissioned and energized with the majority of the outgoing feeder cables and associated

The tools used to evaluate the risk and priority of each substation consisted of consequence-versus-probability matrices for plant capacity and maintenance, health and safety, and other potential hazards.

controls cables not terminated at the substation side and at the load side. During the cut-over phase, attention was needed to identify the energy source for the equipment being cut-over along with the lockout and tagout equipment being worked on. It was also necessary for construction, operations, and maintenance personnel to recognize that there was new energized equipment and understand the hazards associated with the new equipment.

Tie-Ins and Cut-Overs

The tie-in and cut-over plan defined throughout the life of the project was executed in this critical phase, which requires that a team of engineering, construction, and operations personnel be assembled. Each process load will be moved to a new power source, during which time the opera-

tions and maintenance personnel need to be aware of where the loads are controlled and identify the isolation equipment. The operating condition of having two substations controlling the process loads will change almost on a daily basis for an extended period of time. In addition to the tie-ins and cut-overs, other procedures must be executed to validate the modifications and confirm that all safety interlocks are fully functional.

It is important to note that, no matter how well the cut-overs are planned, the execution sequence and schedule will be impacted by changes in process operating conditions (e.g., the backup pumps being out for repair). Therefore, preparing for these changes and making recovery plans must be done in advance.

Demolition

Removing out-of-service equipment was a refinery policy. The project included removing any equipment containing hazardous materials, switchgear, bus duct, batteries, and transformers and provided a very visible air gap in all raceways that will not be removed as part of the project.

Conclusions and Recommendations

The ten-year plan (Table 1) provided a framework to develop a selection priority process to ensure that the proper substations were selected for replacement. The execution of this plan required extensive coordination involving a multidisciplinary team consisting of management, engineering, operations, and construction personnel. This approach has been very successful and, as of today, eight substations have been replaced, upgraded, or taken out of service, and the substation replacement program is progressing as planned (Table 2).

Some of the key benefits of the program approach over individual projects executed at random intervals are as follows.

- Generating a composite list of substations to be replaced and assigning a relative economic impact to each simplified the justification process. Performing a single FEL1 for all substations saves time and resources and provides a roadmap for planning.
- The program allows resource planning and continuity of engineering and construction, realizing efficiencies through standardization of approach and build up of team expertise, which includes personnel rotation and knowledge transfer in an organized manner.
- The construction team moved from one job to the next with little turnover, becoming very efficient in the process. It evolved into an integral part of the team, actively contributing to the design of each substation, particularly in the outside battery limits area where installation costs are the highest.
- The team developed a cooperative relationship with the operators. This helped with work permits and in causing the least impact to the operations.
- Operations and maintenance personnel were deeply involved in the early stages of the project, assisting in the identification of connected loads, some of which were not in use and could be abandoned and others of which appeared abandoned but were used only during upsets or in start-up or shutdown. This information was a valuable rationalizing process of the loads to be included in the new substation.
- Development of cut-over procedures was initially resource-intensive. The program provided a standard approach and forms for cut-overs, streamlining the process and reducing engineering cost as it progressed.
- A significant contribution to the project's success was attributed to a well-defined scope of work during FEL3, prior to full funding. The scope considered minimizing impacts to the operating units, addressed safety in work execution, and allowed for adequate personnel hours to execute the project.

Some key considerations that should be included in a substation replacement project include the following.

- Assemble a team of individuals from different disciplines who will offer multiple views of operating a refinery to perform the risk assessment. Having a team that represents operations, environmental, maintenance, safety, and engineering personnel provides a comprehensive evaluation of the consequences that result from continuing to operate a substation that has a high risk of failure. This same team may also suggest criteria for the replacement substation, such as separating process loads for ease of maintenance, providing electrical power redundancy to critical process pumps for reliability, and minimizing process unit upsets from

a power outage that can result in flaring or impacting the environment.

- Develop and design a replacement substation with safety, environmental, and health considerations during planning, construction, and cut-over.
- Prepare a detailed scope of work that includes minimum risk to an operating unit, maintainability, and meeting operations expectations.
- Prepare a cut-over plan, including written procedures that identify roles and responsibilities and address operating requirements and process availability.
- Include a well-defined demolition plan accounting for hazardous waste disposal, such as mercury, asbestos, lead, transformer oil, and contaminated soils.
- Understand process units' operating conditions and requirements.
- Identify all tie-ins that require unit shutdowns to align the schedules and plan for their timely execution.
- Understand and integrate electrical design for maintenance requirements and process unit operating needs.
- Develop a training plan for maintenance and operations personnel. New substations typically have the latest equipment, such as microprocessor-based relays, and complex fast bus or auto transfer schemes with which maintenance personnel may not be familiar. Maintenance staff should be trained on how to operate and maintain new equipment. Personnel that operate process equipment powered from the new substation should be trained on how the new electrical equipment can affect the way process loads electrically operate and on how to respond to power disturbances and alarms.

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Author Information

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Reference

- [1] *Standard for Purged and Pressurized Enclosures for Electrical Equipment*, NFPA 496, 2017.

