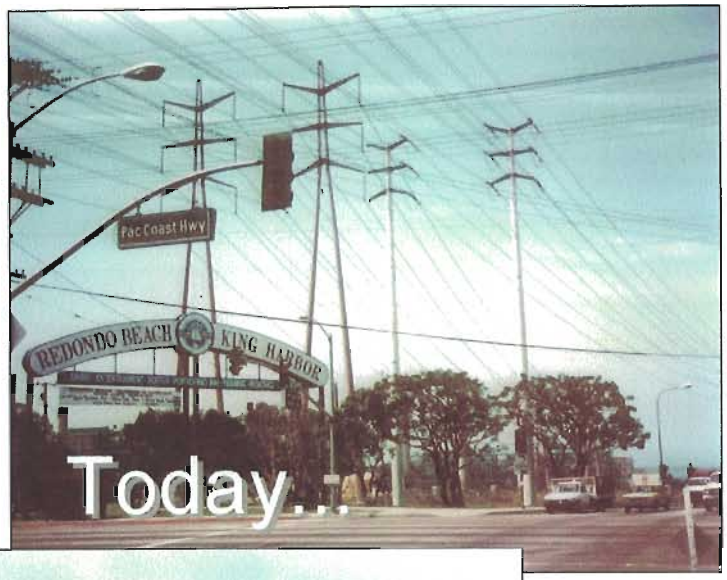
TES ENERGY

TRANSMITTING ENVIRONMENTAL SOLUTIONS



Proposal for modern, compact electric facilities in Redondo Beach, California presented to the Urban Land Institute

March 8, 2000

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TES ENERGY
TRANSMITTING ENVIRONMENTAL SOLUTIONS

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Executive Summary

TES Energy Inc. proposes replacing Southern California Edison (SCE) Redondo Beach electric power delivery systems with modern, compact electric facilities. The present (SCE) power delivery system includes transmission lines, towers, and switchyards located above ground. Modern, compact technology permits relocating the system underground, enhances safety, increases reliability, lowers maintenance costs, and greatly improves the aesthetics of the beach community.

This proposal focuses on the SCE electric power delivery system corridor (right of way) paralleling Herondo-Anita Street from the AES Redondo Beach power plant to Flagler Lane in Redondo Beach, California. The AES power plant occupies 52 acres and AES may reduce the plant space requirement to 12 acres. Providing SCE with compact technology will free approximately 30 acres for development. Tab 3 contains information demonstrating how other utilities aesthetically integrate power plants and delivery systems within urban settings.

In June 1994 Asea Brown Boveri (ABB) developed an estimate to replace the SCE system with modern, compact technology. Their estimate was based upon an electrical one-line diagram provided by SCE. Tab 4 contains the ABB layout drawing for a compact switching system requiring 8000 sq. ft. The SCE switchyard currently occupies 4 acres. This tab also includes literature reviewing a compact switching system operated by the Watson Cogeneration Company in Carson, California. SCE is a part owner of the Watson Cogeneration Company.

Tab 5 provides information on underground power delivery technology. Underground power delivery systems are typically ten times more expensive than equivalent above ground systems. Within the next few years underground power delivery system suppliers may succeed in their goal of reducing the cost ratio to 5 to 1.

ABB project estimates and Bill of Material are included in Tab 6. This tab also includes an ABB Review Article comparing traditional and modern, compact technology benefits and costs.

A letter from the California Public Utilities Commission discussing the development of the Redondo Beach right of way is contained in Tab 7.

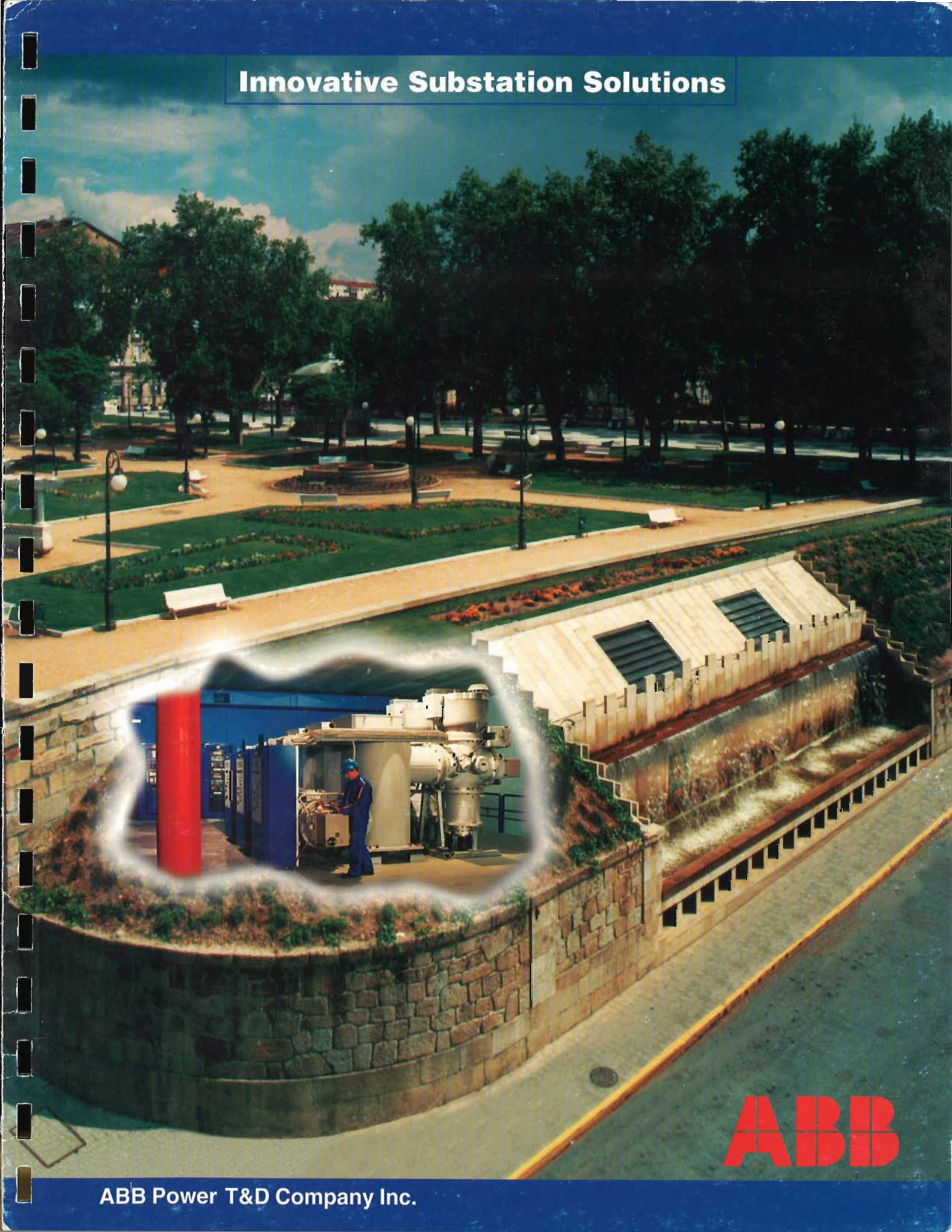
TES Energy is a value added energy service provider. Past experience includes a modern, compact substation for a $1.9 billion Nevada mega-resort. The company is actively developing opportunities in Phoenix, Scottsdale, Long Beach, New Orleans, Pittsburgh, San Diego, and Salt Lake City. Additional information is provided on www.TESenergy.com.


69,000 V
Substation
220,000 V
Substation
Today...


Overhead Power
Delivery System
220,000 Volts
Redondo Beach
Gateway Today
Pac Coast Hwy
Overhead Power
Delivery System
69,000 Volts
REDONDO BEACH
KING HARBOR
Today...


Today...

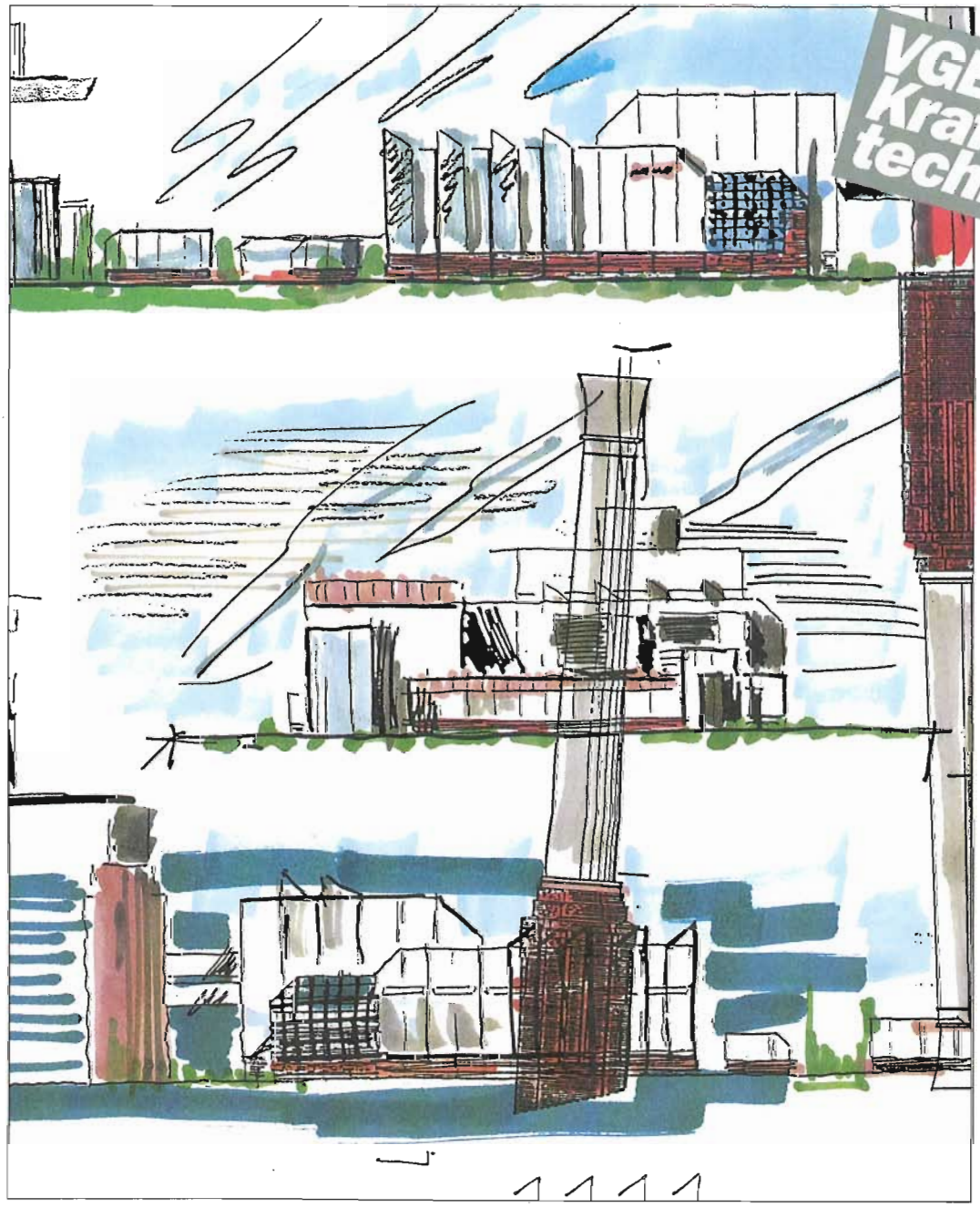
Innovative Substation Solutions



ABB

ABB Power T&D Company Inc.

Architecture in Power Plant Construction



VGB Kraftwerks-technik 3/93

Reprint

ABB Power Generation

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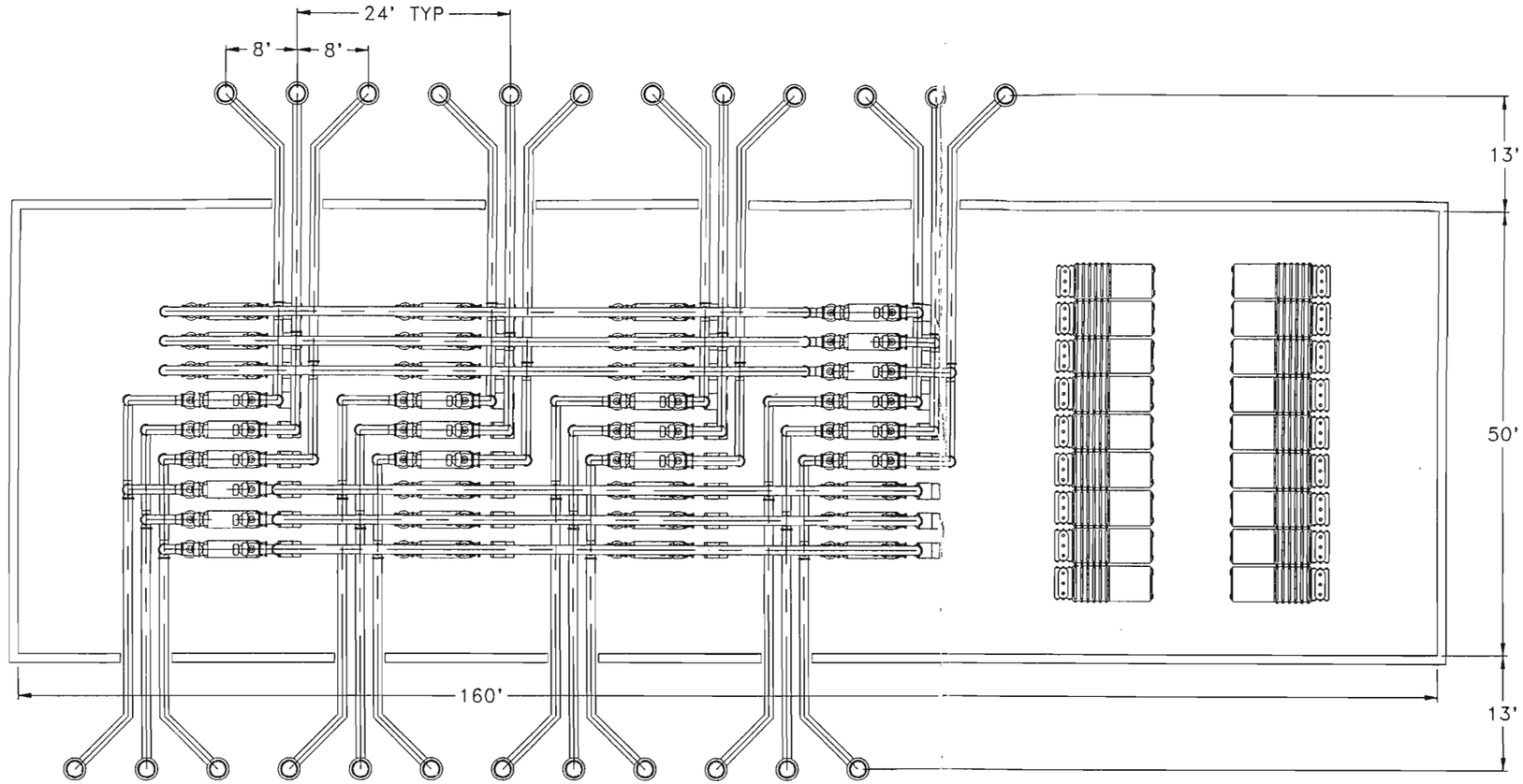
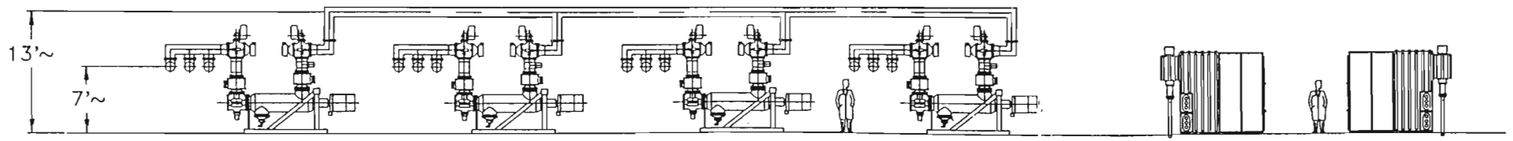




Title	LAYOUT
Type	230 KV GIS
Project Name	SCE/REDONDO BEACH POWER PLANT

ABB
ASEA BROWN BOVERI
CGIT Plant
Westborough, Mass. 01581, USA

MACHINED DIMENSIONAL TOLERANCES UNLESS SPECIFIED ON FACE OF DRAWING

DECIMALS	DIMENSIONS UNDER 6	6-18	OVER 18
ZERO TO 2-PLACE	±.02	±.03	±.06
3-PLACE	±.010	±.020	±.030

DFTR.	9-1-92	UNITS FEET	VC 2
DFTR.		DISK UG	SCALE 1=96
ENG.		SO/NEG NEG-502	A1
ENG.		REV 1	DATE 8-21-92
Q.C.			
MFG.			
I.C.			

ENG. REL DWG.

4D39651

CHANGE

Special print

SF_6 Gas-Insulated Switchgear

An Excellent Choice for Cogeneration Facility

Publication No. CH-AS 4008 89 E

Abstract

With the application of significant plant expansions and cogeneration facilities, the use of higher voltage equipment in the petroleum and chemical industry has become more prevalent. This paper discusses the application of 69 kV and 230 kV gas insulated switchgear, at Watson cogeneration facility in Southern California. The gas insulated switchgear was combined with the high voltage cable, protective relaying, installation and testing to form a single vendor turnkey contract.

Introduction

The cogeneration facility is developed for reliable steam supply to a refinery and has to meet the stringent seismic and environmental guidelines of Southern California. It includes four gas and two steam turbine generator units with two connections, on the 230 kV level, to the local utility. The generated output is 385 MW (Figure 1). For the interface, a breaker and a half scheme is used on the 230 kV level with a total of twelve breakers, and at 69 kV a six breaker ring bus arrangement to fulfill the energy supply requirement of the refinery.

GIS Versus Conventional Installation

In the early stages of the project, a conventional outdoor switchyard consisting of oil circuit-breakers, take-off towers, and other outdoor equipment, was considered with a plot space of 165,000 square ft for the 230 kV and 69 kV installation. This severely limited the space available for process related facilities, and also significantly influenced the layouts due to the overhead transmission lines.

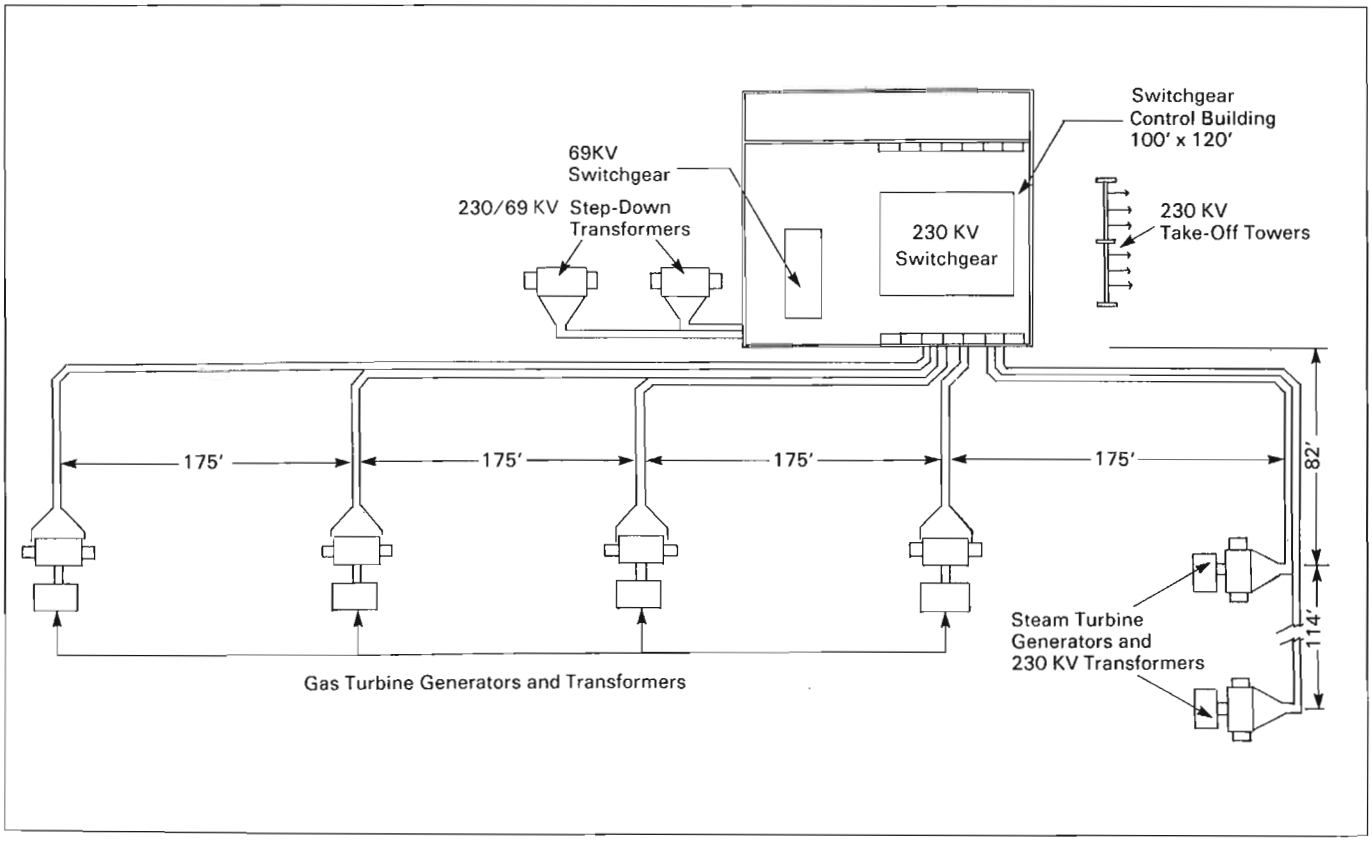
Use of SF_6 gas insulated switchgear (GIS) eliminated these short comings since, besides a 75 to 90 percent reduction in the required space for the switchgear with transformer, no additional clearance is required with completely grounded enclosures, including cable connection to the transformer with SF_6-oil bushings. Figure 2 shows a cross-section of the 230 kV GIS in one and a half breaker arrangement.

The superiority of GIS over conventional installation under seismic conditions can be supported in a number of ways. Gas insulated installation is characterized by the high strength mechanical connections between station components. The dynamic behavior of each component is improved by the interaction between the adjoining components plus the foundation to which the components are attached.

Additionally, the GIS station is inherently of low profile, low center of gravity design. A detailed seismic analysis defined the requirements of the concrete foundation and supports of the GIS, including its connection.

Standards prepared by Working Group 70.1 (today's Subcommittee KO) of the IEEE Substations Committee, and also the International Electrotechnical Commission (IEC) provided the basis for equipment specifications. [1] [2]

Figure 1
Cogeneration plant, plot plan



General Design Characteristics of GIS

SF_6 is a physiologically inert non-toxic gas and is harmless. Today it it considered as a widespread insulating gas, non-aging and is nearly perfect insulator. Minor decomposition products of SF_6 gas during frequent short circuit interruptions are absorbed by the aluminium oxide filters in the circuit-breaker compartment. [3] [4]

Conical spacer insulators of barrier type separate the independent gas zones and additionally support the line parts concentrically within the enclosure.

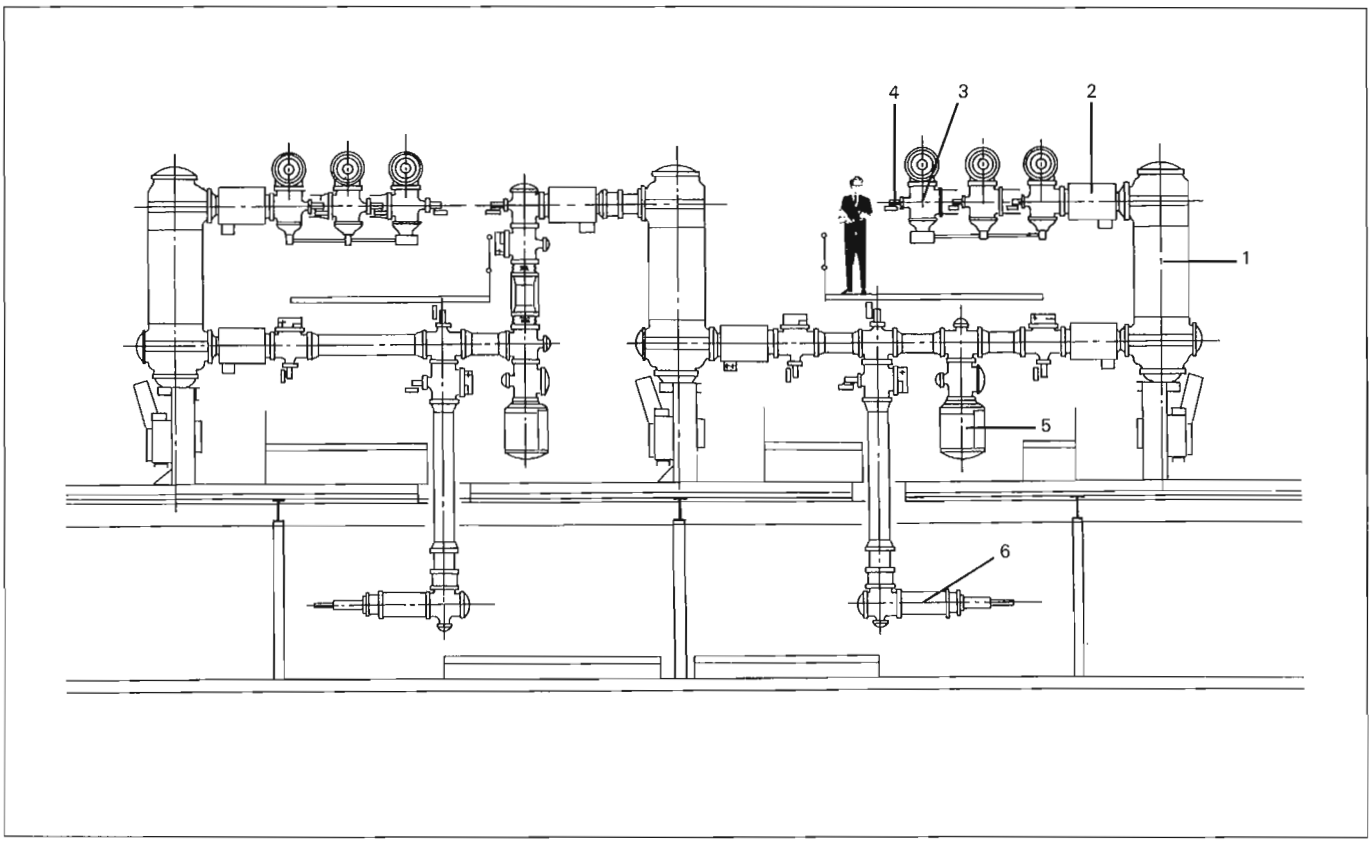
A reduction of the withstand voltage occurs only in case of a loss of gas density; therefore, gas density monitors are located in each section, or gas zone, of the GIS. The density monitoring system is usually equipped with two sets of alarm contacts that will provide alarm signals for refilling and blocking at falling density. It should be noted that in the event of gas loss, the GIS will withstand line to ground voltage at atmospheric (zero psig) pressure. Guaranteed gas loss is below 1% per year. [5]

Circuir breakers use SF_6 as the dielectric and arc quenching medium. Breakers with a separate gas zone operate at a higher gas pressure than the bus.

Disconnect switches used for breaker or bus isolation are capable of interrupting the charging currents associated with the normal bus capacitance. To comply with usual operating procedures, viewing provisions in the switch enclosures allow visual confirmation of the disconnect and ground switch contact position.

Grounding switches for maintenance work are provided with slow moving contacts without make or break capability. For fault closing, fault initiating, or ground current interruption, additional control options are available, and are generally used at line exits, cable and transformer connections.

Figure 2
Elevation view, typical bay, 230 kV GIS
1 Circuit-breaker
2 Current transformer
3 Disconnect switch
4 Ground switch
5 Potential transformer
6 Cable pothead



Cubicle Type Gas Insulated Equipment

The technical advantages of SF_6 equipment can be extended to the 36–69 kV subtransmission level. This equipment differs considerably from the standard pipe type designs. Two main characteristics are: 1) cubicle enclosures offering a more economical switchgear for this voltage range, and 2) extremely low operating pressures. The design meets the withstand voltages at atmospheric pressure, and the slightly higher gas pressure is required only for gas supervision.

The gas insulated cubicle systems are completely factory assembled with installation at the site being comparable with that for conventional medium voltage switchgear.

Figure 3 shows a cross-section of a typical cubicle with built-in components, compartmentalized by their function: breaker section, bus sections, take-off section.

The main technical data of the 230 kV and 69 kV GIS are summarized in Table I.

Table I
Technical data, GIS

Rated voltage	230 kV	69 kV
Max. service voltage	242 kV	72.5 kV
Continuous current	3000 A	1250 A
Short circuit current	63 kA	31.5 kA
BIL	900 kV	350 kV
60 Hz 1 min. withstand	460 kV	160 kV
Control voltage	125 VDC	125 VDC
Aux. voltage pump	208 VAC	208 VAC
Aux. voltage heater	120 VAC	120 VAC
Number of feeders	12	6
Single line configuration	1 ½ Breaker	Ring bus
No. of interrupters per breaker pole	2	1
SF_6 gas pressure range		
– breaker psig	72–87	72–87
– compartment psig	42–64	0–3
Allowable no. of operations before maintenance		
– full short circuit current	15	14
– load interruption	5000	1500
– no load operation	5000	5000

Power Cable

Potheads are used to connect the GIS substation to incoming power cables (Figure 4). They are similar to conventional potheads with the exception of a smaller pothead body. An enclosure surrounding the pothead connects directly to the bus system using a common source of SF_6.

The use of high voltage cable in substations in general, and specifically for GIS, allows the utmost flexibility in station layouts. Most convenient are solid dielectric cable with XLPE insulation, available up to 420 kV system voltage since they do not require any supervisory system.

Low pressure oil filled cable, as used for the 230 kV connection to the transformer in this station, allows a similar flexibility for cable end bushing connections to the GIS without modification of the GIS design. GIS design with special transition compartments for high pressure oil cable (HPO) is required to allow the addition of the enclosure after installation of the cable end bushing. Such a special design allows also repair of cable terminations at a later date without changing the position of the rigidly installed steel pipes of HPO cables.

Figure 3
Cross section through cable feeder – 69 kV GIS
1 Voltage transformer
2 V.T. isolating device
3 Cable-end-unit
4 Isolator with earthing switch
5a Busbar system I
5b Busbar system II
6 Busbar insulator
7 Current transformer
8 Terminal bushing for C.T. and V.T. secondaries
9 Pressure relief device with deflector funnel
10 Gas barrier insulator
11 Circuit breaker
12 Drives for isolators and earthing switches
13 C.B. drive

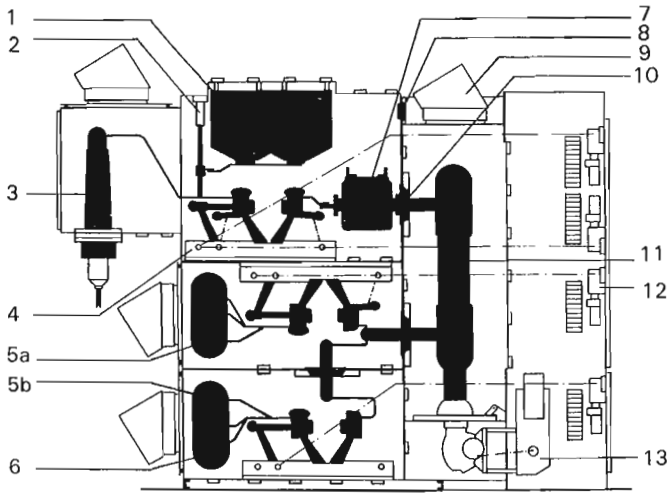
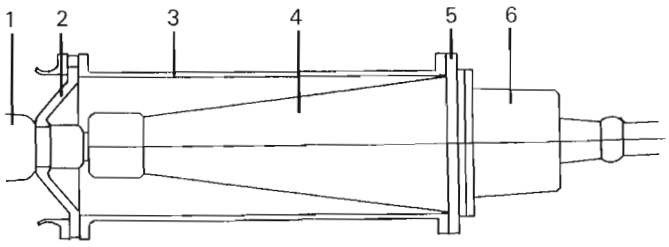


Figure 4
Cable pothead
1 Connection to switchgear
2 Barrier insulator
3 Enclosure
4 Cable-end bushing
5 Connecting flange
6 Cable sleeve



Scope of Supply

The decision for gas insulated switchgear eliminated a great number of concerns. Obviously, besides the enormous space reduction from 165,000 sq. ft. to 12,500 sq. ft., it reduced the cost for site preparation, shortened the length of control cables, eliminated multiple purchase orders and order handling, reduced the amount of overall engineering, allowing easy access to all equipment and, with the installation in a building, providing exact scheduling of the installation phase independent of ambient weather conditions.

The independence to ambient conditions is also important for any maintenance work since it can be performed at any time of the day or year. Besides the higher safety and security, all energized high voltage components as well as auxiliary equipment, are installed in a controlled environment without any exposure to outside pollution. [8] [9] [10]

For the connection between the generator step-up transformers and the 230 kV GIS as well as the step-down transformers and 69 kV GIS, low pressure oil filled and solid dielectric cables were installed in pre-fabricated concrete trenches.

Due to the compressed project schedule of 12.5 months between the go-ahead for manufacturing and energization date of the station, the turnkey package included, besides the 230 kV and 69 kV GIS, the supply and testing of 230 kV low pressure oil filled cables, ground grid design, as well as protection and control equipment [11]. Critical milestones and the overall schedule were established prior to the quotation stage.

Detail design information, including dimension layouts and equipment weights, were important in the design of the building, structures and interphases with the rest of the equipment. Provisions included required the manufacturer to be in compliance with local rules and regulations, as well as the responsibility for obtaining the necessary approval of the local authority for meeting applicable safety standards.

Station Design and Schedule Coordination

A tour of the GIS manufacturing facilities was the first agenda item in the project schedule. This meeting permitted an inspection of the GIS equipment proposed and brought together key user and supplier personnel responsible for completing the project. It allowed to discuss the critical path for successful completion of the installation and to define exactly the transition points to items supplied by others since the tight schedule did not allow last minute changes.

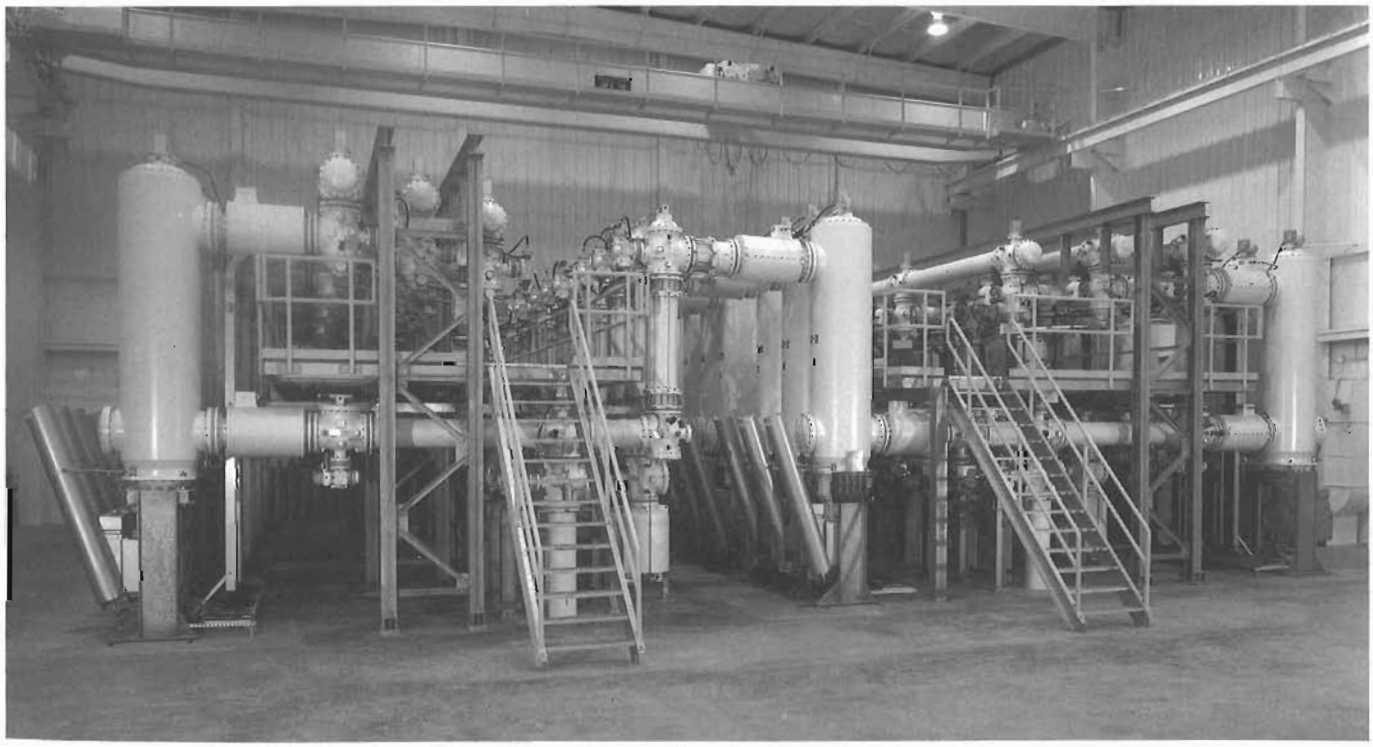
The drawing approval process was aided considerably by a scale model of the station. It permitted a clear understanding on the installation process, and identified aisleway locations for convenient operation and maintenance of the gas insulated equipment. In addition, the model enabled the client to finalize the building design, and to determine the most efficient routing for the power cable.

Throughout the manufacturing process, periodic meetings were held to meet critical milestones and to coordinate with the civil construction proceeding at the substation site.

Quality assurance audits were conducted by the client to assure full compliance with the manufacturer's quality assurance.

Factory tests witnessed by customer representatives included mechanical and dielectric tests, including partial discharge measurement of each shipping unit in accordance with factory internal and ANSI/IEC requirements.

Picture 1
This picture shows the 230 kV GIS with vertically arranged breaker after installation. Walkways allow easy access to disconnect switch operators and for viewing the contact position.



Installation

Prior to receiving equipment, the building was approved by the manufacturer's service engineer to start with the installation work. Incoming equipment was identified, checked for shipping damage, and stored based on the installation sequence. Selected spare material was supplied to prevent any slow-down in the installation in case of shipment damage. It may be noted that the equipment from the manufacturing facilities arrived at site in excellent condition.

Installation began with the placement of the three breakers of the first bay. All connections were made by bolted flanges with plug-in finger contacts (Figure 5).

Parallel with the GIS installation, the cable between the switchgear building to the transformers was laid and terminated. The make-up of the cable pothead and connection to the switchgear was greatly simplified by the use of low pressure oil cable.

The flexibility of this cable system eliminated the need for special connectors or installation techniques normally required for pipe type cable. An advantage of GIS equipment is that, to a greater extent, many installation activities can be performed simultaneously. [11]

After completion of the cable connections, and various control checks on the gas and operating systems, the installation successfully passed the dielectric high voltage commissioning test. Cables and potential transformers were installed but electrically isolated during these tests. The complete system was again tested at a lower voltage with the PT's and cables connected. After calibration, final commissioning tests were done on the station protection system. The interfaces between the connected utility and the refinery controls were commissioned after testing with an event recorder. The project was completed ahead of schedule on October 4, 1987.

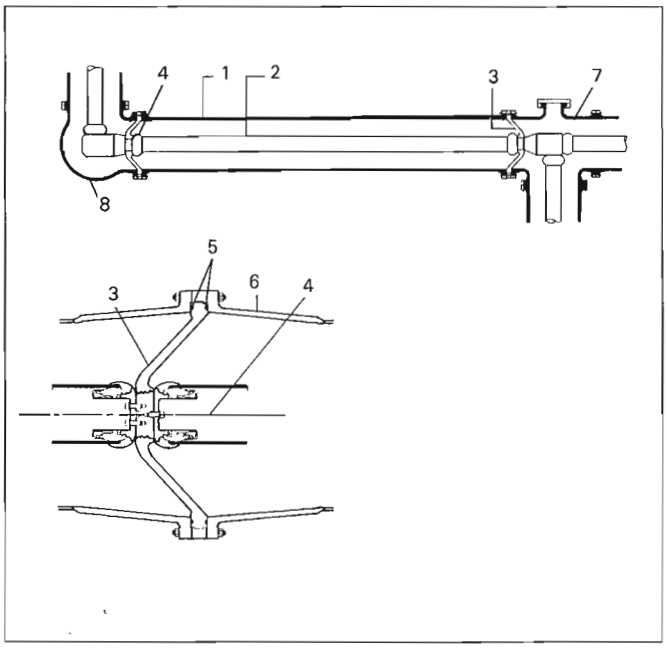
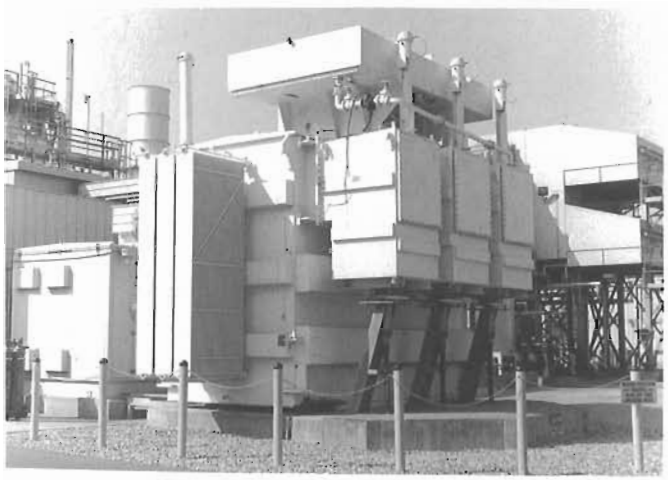
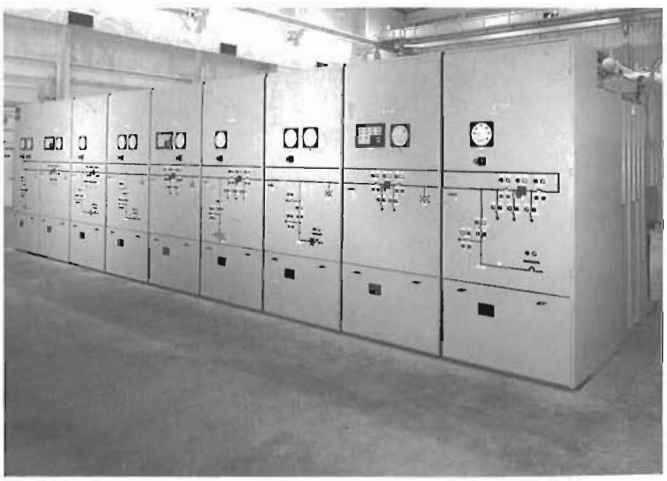


Figure 5
Typical bus system – 230 kV GIS
1 Enclosure tube
2 Conductor
3 Support insulator
4 Plug-in contact
5 "0"-Ring seal
6 Flange
7 Tee assembly
8 Elbow assembly

Picture 2
This picture shows the 230 kV oil cable connection to the transformer. Such a design allows a low profile installation.



Picture 3
The line up of the 69 kV SF_6-insulated cubicles shows on the front of the cubicles the single line diagram with local control components.



Conclusion

Gas insulated equipment offers considerable advantages for installations in cogeneration facilities. With cable to oil bushing connected transformers, any exposed high voltage connections are eliminated, which allows safe access to all control equipment and unhindered accessibility within the overall equipment complex of a refinery.

The single vendor turnkey contract provides clear project management resulting in minimum engineering costs, the most efficient coordination of all sub-vendors, and the fastest possible project completion.

The advantage of a well proven GIS design ensures minimum maintenance. The main operating components have been developed for long maintenance intervals, nevertheless, a well administered checking and preventive maintenance program is planned. It will ensure continuous operation and eliminate costly, unscheduled outages.

As an example picture 4 demonstrates the easy accessibility for supervision and operation even with the compact arrangement of the disconnect switch, ground switch and potential transformer combination.

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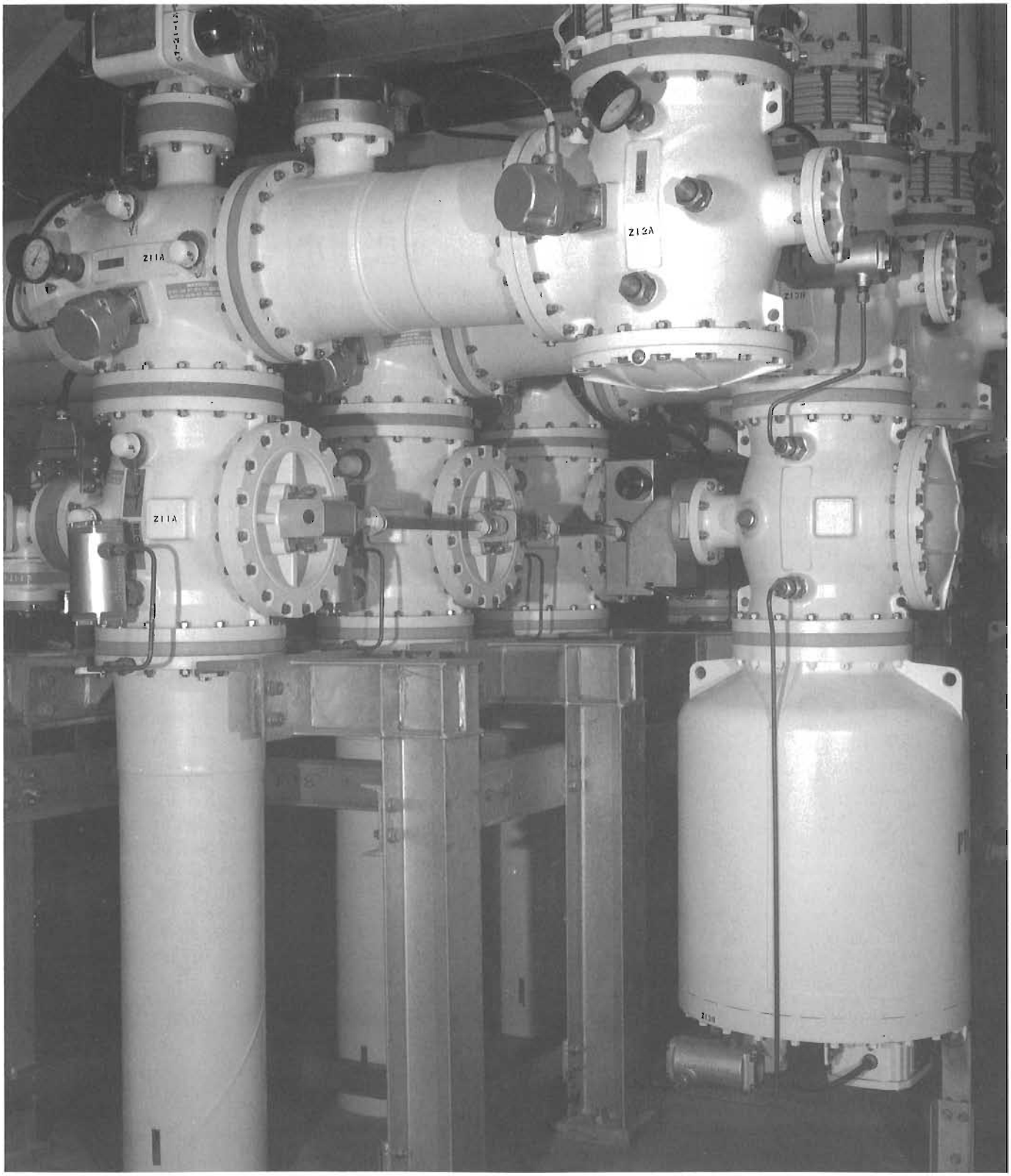

Picture 4
Disconnect switch, grounding switch and potential transformer combination

ABB
ASEA BROWN BOVERI

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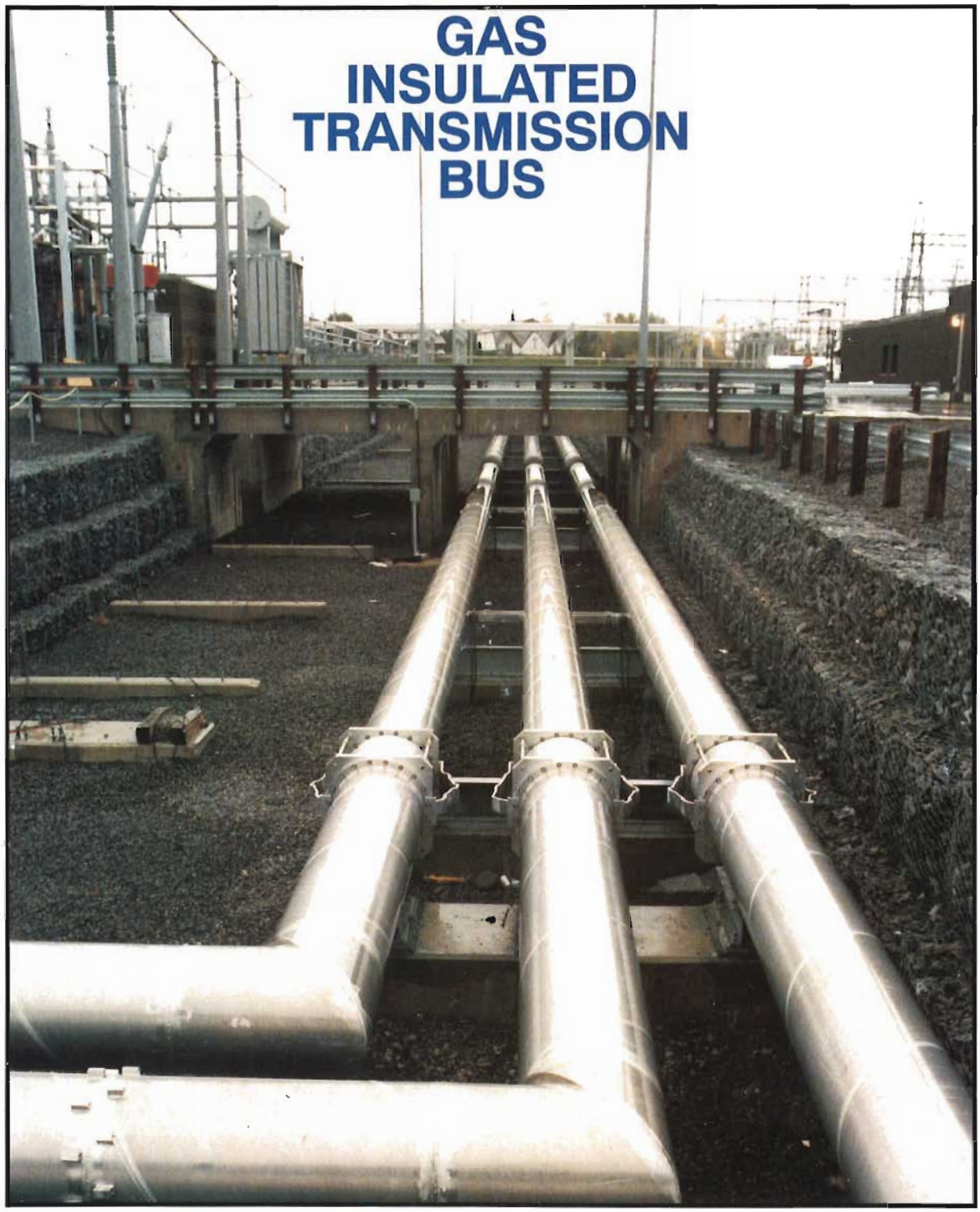
Printed in Switzerland (8903-2000-0)

GAS INSULATED TRANSMISSION BUS



Manufactured in Westborough, Massachusetts USA

ABB

General

Compressed Gas Insulated Transmission Bus System

The ABB Compressed Gas Insulated Transmission Bus System Type CGIT, also known as Gas Insulated Cable, provides a compact, highly reliable and economical alternative to conventional cable systems and overhead lines for bulk power transmission. The first Compressed Gas Insulated Transmission system (CGIT) installation was made in the beginning of 1970. Since then, more than 34 miles (55 km) of CGIT at voltage levels from 115 kV through 1200 kV have been delivered and installed world-wide.

The Advantages

The advantages of the ABB Compressed Gas Insulated Transmission System Type CGIT are:

- Suitable for voltage ratings from 72.5 kV through 1200 kV and current ratings through 5500 Amps per feeder.
- Matches Ampacity of overhead lines, circuit-for-circuit.
- No auxiliary pumping or cooling equipment.
- No fire hazard.
- Simple and inexpensive terminations.
- Small right-of-way requirements.
- The safety of dead-front construction.
- Low installation costs.
- Low losses means low operating costs.
- Very low maintenance costs.
- Long life.
- High reliability.

242kV, 3000A, Substation (Claireville, Ontario Hydro, Canada)

- No radio noise interference.
- No appreciable external magnetic fields.
- Very low dielectric losses.

CGIT Applications

The ABB Compressed Gas Insulated Transmission Bus Type CGIT can be used as an alternative to conventional cables, as an exit for conventional or gas insulated substations, and to solve specific problems of limited space or severe environment.
The ABB CGIT can be installed in a number of different ways:

- At ground level.
- Elevated above ground on pillars or support structures.
- Below grade in an open or covered trench.
- Directly buried underground.
- Vertically in tunnels, shafts or towers.
- Hung from existing substation structures.

The CGIT Concept

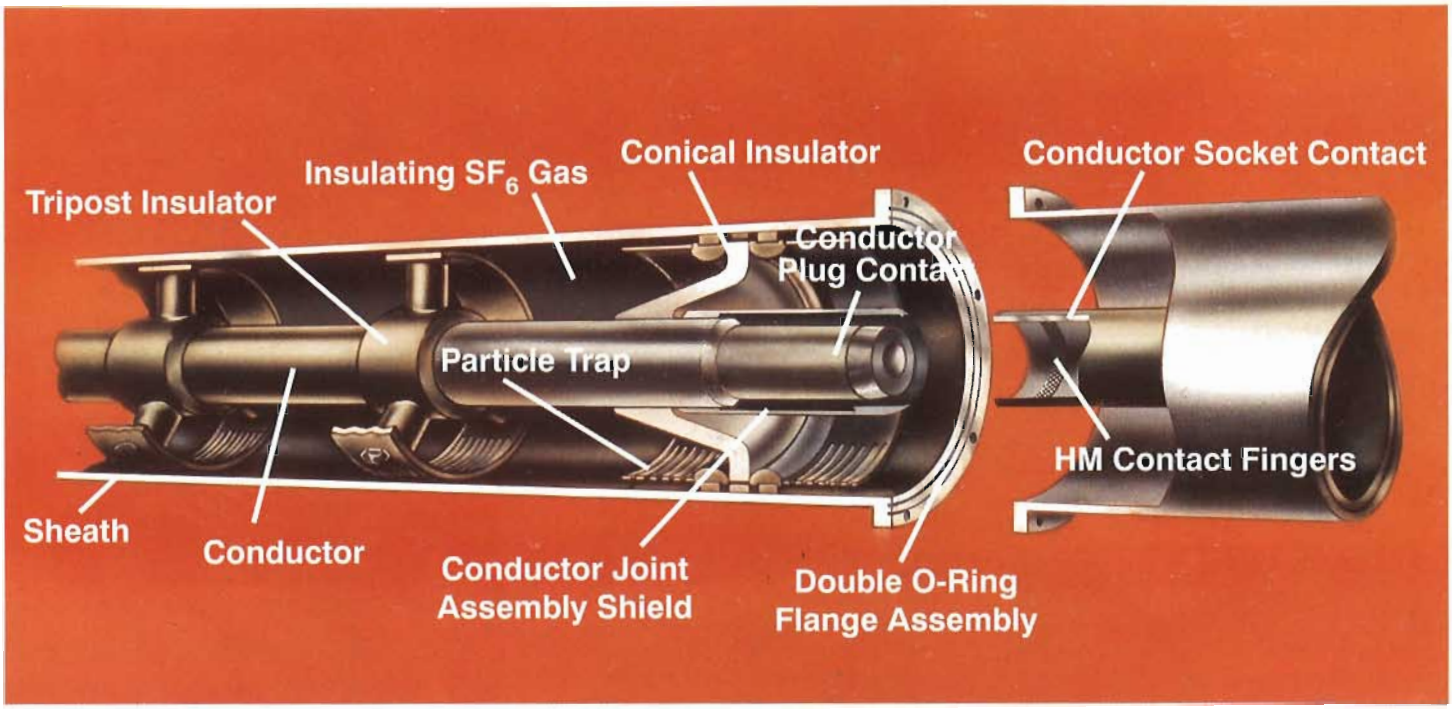
The individual components of a CGIT bus system include: straight sections, elbow or tee sections, transformer or cable interfaces, and SF_6-to-air bushings. GIS interfaces are designed to ease field assembly. The use of mitered elbows and tees conserves space and simplifies the layout while maintaining system flexibility. Field joining can be accomplished using either double o-ring bolted flanges or simple MIG butt welds.

Two types of insulators are used. Open tripost insulators are used for the majority of insulators and provide a highly reliable open con-

362kV, 4000A SF_6 Busduct with SF_6-to-air bushing (Dunwoodie Substation, Consolidated Edison of New York)

500kV, 4000A CGIT in a tunnel (Revelstoke B.C. Hydro, Canada)

Cover: 550kV, 4000A Substation (Hawthorne, Ontario Hydro, Canada)



Typical section view of ABB CGIT bus.

struction allowing free passage of gas inside the bus. Conical gas barrier insulators are available to limit the size of gas compartments.

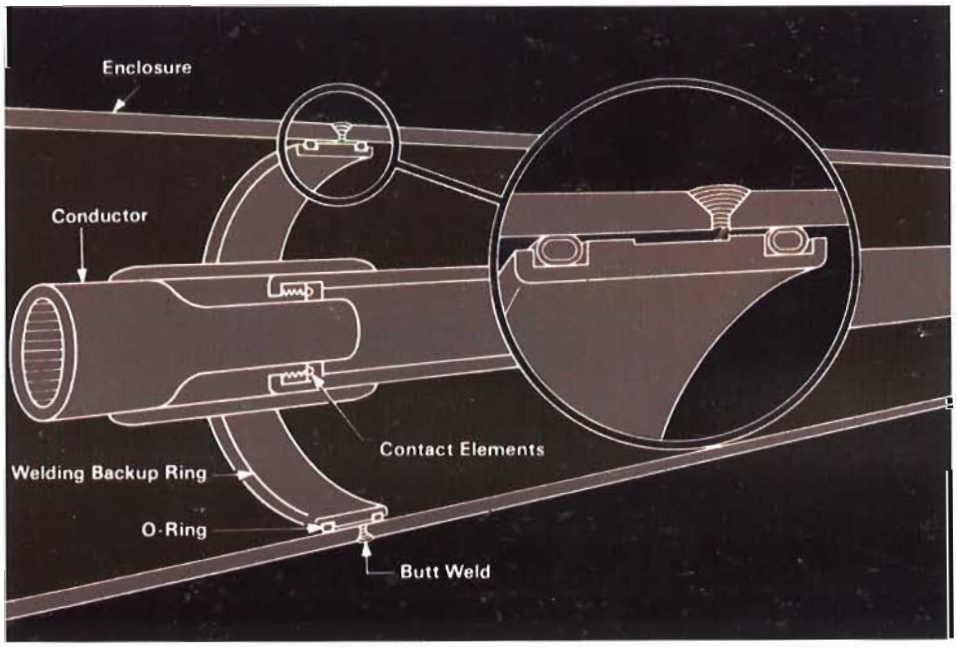
Aluminum alloy is used for all ABB CGIT bus. Aluminum's light weight and corrosion resistance keeps installation and maintenance costs low. Foundation sizes can be kept to a minimum and painting is usually not required even in the most severe operating environments.

The CGIT Design and Details

Each phase of the Compressed Gas Insulated Transmission Bus Type CGIT consists of a grounded aluminum alloy enclosure tube which houses a concentric tubular aluminum-alloy conductor arranged in a coaxial configuration. The insulating medium is the same Sulfur hexafluoride (SF_6) gas used extensively in electrical power equipment. The conductor is supported by TRI-TRAP® vacuum cast epoxy insulators. There are two types of insulators, triposts and cones. The tripost insulator allows free flow of gas around the insulator and the conical insulators are used to divide the CGIT into separate gas compartments. The conical insulators are capable of withstanding the pressure differential exerted by

CAD stations are used extensively during the design process.

ABB's CGIT is designed to accommodate sharp changes in directions.



Cross section of welded field joint

8930

PACIFIC COAST HWY.

S. ANITA ST.

BEACH

HERMOSA

REDONDO

ATSF

ARKMORE R.Y. R/W

AVE.

VALLEY DR.

N. FRANCISCA

A.T.S.F. R.Y.

S. PACIFIC AVE.

S. N. GUADALUPE AVE.

S. N. GERTRUDA AVE.

S. N. FRANCISCA AVE.

TOWNSITE

S. N. ELENA AVE.

OF

BROADWAY

REDONDO

S. N. CATALINA AVE.

CARNELIAN

BEACH

S. N. BENITA AVE.

SC. RY TURN TABLE TR.

LEASE TO SALVATION ARMY

1786

2341

TR

SUB

$10M

10,000

10K

1200'

$8.4M

$5.6M

800'

$9M

AES SUB

$5.6 M

CITY

LAKEVIEW

ST.

OCEAN

BEACH

RAILWAY

HARBOR

(HERMOSA AVE.)

SUB

BERYL

THE STRAND

BORY.

PACIFIC

S.C.E. CIRCULATING WATER TUNNELS

LEASE AREA

S.C.E. LEASE AREA

OCEAN

SCALE

LANDS OWNED IN FEE BY SCE Co. AS OF 4-3-72

SURVEY BY	
PLOTTED BY	C.D.S.
TRACED BY	C.D.S.
LETTERED BY	C.D.S.
CHECKED BY	C.D.S.
SCALE	1"=100'
DATE	1968

MS 047-082

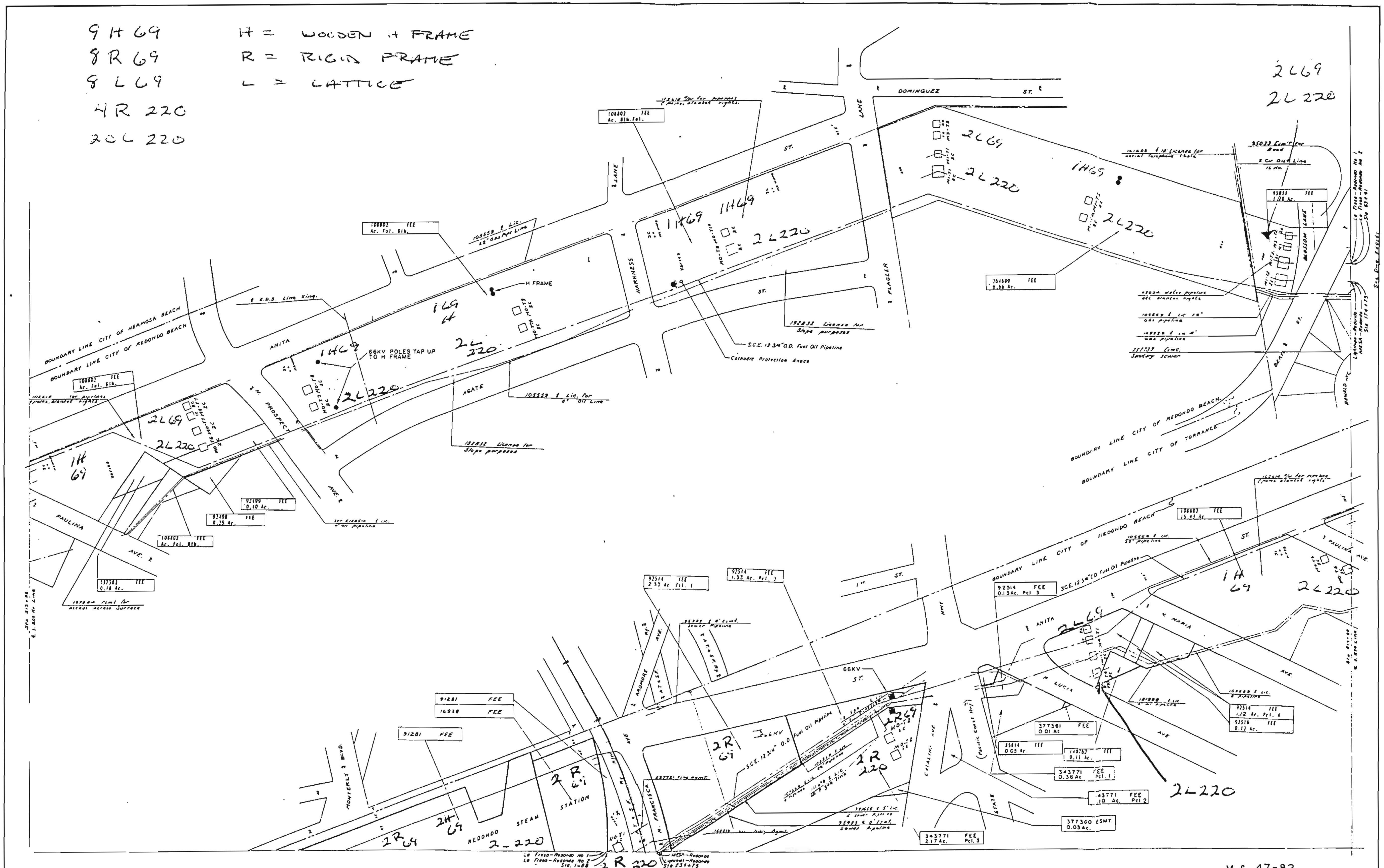
SOUTHERN CALIFORNIA EDISON COMPANY
LOS ANGELES, CALIFORNIA

LOCATION: CITY OF REDONDO BEACH

REDONDO BEACH GENERATION STATION

LOS ANGELES COUNTY

8930-1



	REDONDO BEACH	TORRANCE
MESA - Redondo	5719	281
Lighthipe - Redondo	5719	281
La Fresa - Redondo No 1	5867	286
La Fresa - Redondo No 2	5867	286

REVISIONS				DATE	REVISIONS					DATE
4-1-53	11-66	12-78	4-88							
5-66	12-69	5-80	3-91							
9-67	12-70	3-81								
10-68	12-71	10-82								
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CROSS REFERENCES
536252 536260 M7493
L.A. Co. Inv: 40-63C40, 40-63D
40-LJA-L858L-M22033-M22083
62394-M22084, 589126-589129 inc.

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PLOTTED BY	J L Moriarty
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LETTERED BY	J A Latyvak
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DATE	10-54

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M. S. 47-82

SOUTHERN CALIFORNIA EDISON COMPANY
LOS ANGELES, CALIFORNIA

LOCATION 220 KV R/W

REDONDO - LA FRESA

540140-19

INDEXED - MICROFILMED

INV 1973

ABB
ASEA BROWN BOVERI

SECTION 2
PRICING SUMMARY
69 kV & 220 kV REDONDO BEACH
BEAUTIFICATION PROJECT
BASE BID

- Disassemble Existing 69 kV Overhead System (0.7 Mile)
- Disassemble Existing 220 kV Overhead System (0.7 Mile)
- Disassemble Existing 69 kV Substation
- Disassemble Existing 220 kV Substation
- Design, Fabrication and Installation of the 69 kV Gas Insulated Substation (16 Breaker, Multi-ring Configuration)
- Design, Fabrication and Installation of the 220 kV Gas Insulated Substation (12 Breaker, 1 1/2 Configuration)
- Installation of 69 kV Solid Dielectric Cable (3 Circuits, 0.7 Mile)
- Installation of 220 kV Solid Dielectric Cable (4 Circuits, 0.7 Mile)

$30,354,000

ABB
ASEA BROWN BOVERI

SECTION 2
SCOPE OF SUPPLY SUMMARY
69 kV & 220 kV REDONDO BEACH
BEAUTIFICATION PROJECT
BASE BID

- Disassemble Existing 69 kV Overhead System (0.7 Mile, See Note 1)
- Disassemble Existing 220 kV Overhead System (0.7 Mile, See Note 1)
- Disassemble Existing 69 kV Substation (See Note 2)
- Disassemble Existing 220 kV Substation (See Note 2)
- Design, Fabrication and Installation of the 69 kV Gas Insulated Substation (16 Breaker, Multi-ring Configuration)
- Design, Fabrication and Installation of the 220 kV Gas Insulated Substation (12 Breaker, 1 1/2 Configuration)
- Installation of 69 kV Solid Dielectric Cable (3 Circuits, 0.7 Mile, See Note 3)
- Installation of 220 kV Solid Dielectric Cable (4 Circuits, 0.7 Mile, See Note 3)

Notes:

1. Foundation is assembled to be chipped down to one foot below finished grade.
2. All exposed piers will be chipped away and existing site will be raised by 18". (Note: This will eliminate the need for excavation of the existing foundations.)
3. Estimate is based on boring with casing across commercial highway and direct buried or below grade trenches across residential streets.

ABB
ASEA BROWN BOVERI

SECTION 4
PRICING SUMMARY
69 kV & 220 kV REDONDO BEACH
BEAUTIFICATION PROJECT
OPTION A

- Disassemble Existing 69 kV Overhead System (0.7 Mile)
- Disassemble Existing 220 kV Overhead System (0.7 Mile)
- Disassemble Existing 69 kV Substation
- Disassemble Existing 220 kV Substation
- Design, Fabrication and Installation of the 69 kV Gas Insulated Substation (16 Breaker, Multi-ring Configuration)
- Design, Fabrication and Installation of the 220 kV Gas Insulated Substation (7 Breaker, Ring Configuration)
- Installation of 69 kV Solid Dielectric Cable (3 Circuits, 0.7 Mile)
- Installation of 220 kV Solid Dielectric Cable (3 Circuits, 0.7 Mile)

$25,710,000

ABB
ASEA BROWN BOVERI

SECTION 2
SCOPE OF SUPPLY SUMMARY
69 kV & 220 kV REDONDO BEACH
BEAUTIFICATION PROJECT
OPTION A

- Disassemble Existing 69 kV Overhead System (0.7 Mile, See Note 1)
- Disassemble Existing 220 kV Overhead System (0.7 Mile, See Note 1)
- Disassemble Existing 69 kV Substation (See Note 2)
- Disassemble Existing 220 kV Substation (See Note 2)
- Design, Fabrication and Installation of the 69 kV Gas Insulated Substation (16 Breaker, Multi-ring Configuration)
- Design, Fabrication and Installation of the 220 kV Gas Insulated Substation (7 Breaker, Ring Configuration)
- Installation of 69 kV Solid Dielectric Cable (3 Circuits, 0.7 Mile, See Note 3)
- Installation of 220 kV Solid Dielectric Cable (3 Circuits, 0.7 Mile, See Note 3)

Notes:

1. Foundation is assembled to be chipped down to one foot below finished grade.
2. All exposed piers will be chipped away and existing site will be raised by 18". (Note: This will eliminate the need for excavation of the existing foundations.)
3. Estimate is based on boring with casing across commercial highway and direct buried or below grade trenches across residential streets.

Comparison of GIS and AIS systems for urban supply networks

Studies carried out by ABB show that for urban supply networks the combination of HV gas-insulated switchgear (GIS) and HV cable has important advantages over systems with air-insulated switchgear (AIS) and overhead lines. Due to their compactness and flexibility, GIS substations can be located close to load centers, allowing a much more efficient configuration for both the HV system and the MV distribution network. The saving in investment and operating costs more than compensates for the higher cost of the GIS and cables. Benefits include higher reliability and the option of integrating a complete GIS substation in an existing building, eg when extra site area is not available.

Besides the vital role they play in modern market economies, electricity supply systems also have a large impact on the environment, making them subject to changes in social paradigms. It is in part due to this that the medium-voltage systems supplying power to urban areas are designed today almost entirely as cable networks with indoor switching stations. Besides its reduced visual 'intrusion' on everyday life, gas-insulated switchgear (GIS) also offers operators of high-voltage supply systems reliable and flexible solutions in areas where load densities are high and substation sites have to be kept small. Urban supply systems combining GIS technology and HV cable are safe, reliable and environmentally benign 1.

A direct comparison of the component investment for identical switchgear configurations suggests that the GIS variant is more costly than the air-insulated switchgear (AIS) solution. However, such a comparison does not take into account the fact that by locating a GIS transformer substation close to the load centers a far more efficient network structure is obtained at both the HV and the MV distribution level. As a result, the investment and operating costs are reduced.

To quantify the respective impact of AIS and GIS technology at the HV and the MV levels of an urban supply system, a look is taken in the following at an existing network with a maximum load of 120 MW. The MV network is optimized for each of the HV variants (GIS and AIS), in each case for distribution voltages of 10 kV and 20 kV, so that four different HV/MV networks are evaluated. The comparison is based on the life-cycle costs of the different supply concepts.

Werner Zimmermann
André Osterholt
Dr. Jürgen Backes
ABB Calor Emag Schaltanlagen AG

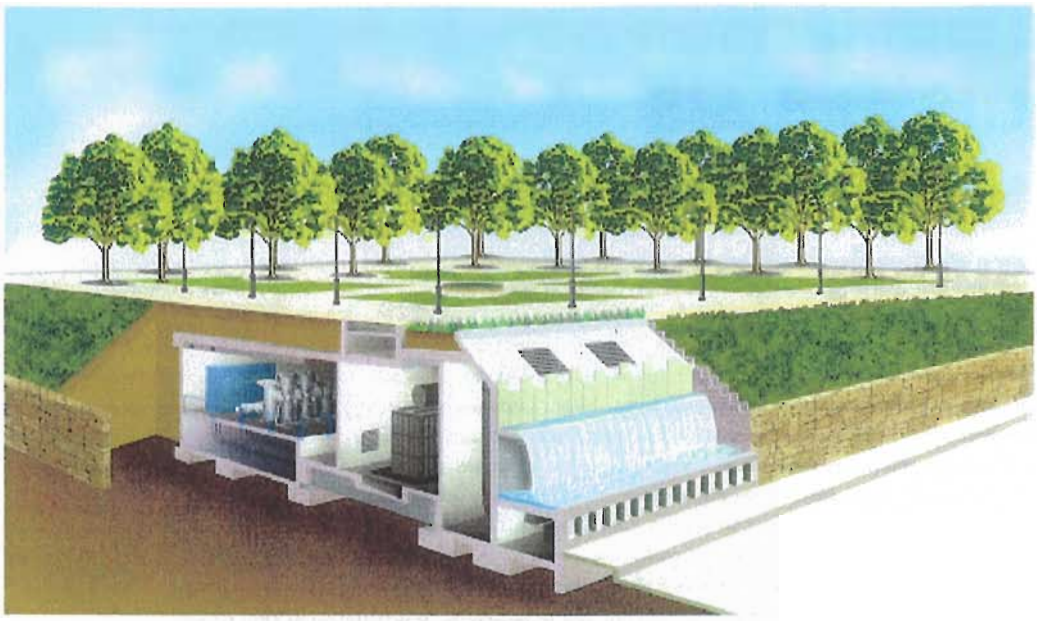
Design of the AIS/GIS network variants

High-voltage network

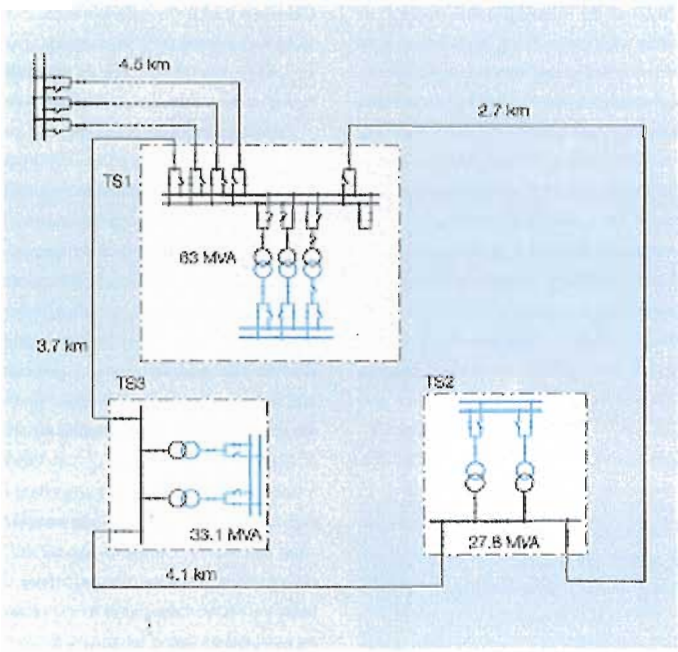
The best locations for the HV injections into the distribution network depend to a large extent on the technology (AIS or GIS) chosen for the HV system. Sites which are large enough for AIS substations are seldom available, and when they are their cost is extremely high. But it is not just the smaller size of the site that makes GIS the lower-cost option: GIS is also the more economic alternative when expanding or replacing existing substations. An inner-city site that has been used previously for an AIS installation can be sold or rented out and the income used to help finance the new substation. The compactness of GIS enables an HV transformer substation to be fully integrated in an existing building, which may only have to be made higher or have a basement added.

The issue of space extends beyond the transformer substations to the high-voltage connections. Overhead lines are today practically 'no-go' as an option for inner-city areas. And even where rights-of-way are available, these can often be utilized more economically in other ways. Typical complaints about overhead lines are that they are unsightly and generate electromagnetic fields, the effects of which are subject to constant and intensive public debate.

Modern-day HV cable not only offers a high level of reliability but also some technical benefits for overhead line connections. Given these advantages, there is today no realistic alternative to HV cables for electric supplies in urban areas.



Use of ABB gas-insulated switchgear allowed the 132-kV transformer substation Barbaña in the center of Orense, Spain, to be constructed underground and a park built over it which harmonizes with the surroundings. The sound of the waterfall, which acts as a heat-exchanger, hides the noise made by the fans. 1



GIS variant of the 110-kV network 2

TS1, 2, 3 *Transformer substations 1, 2, 3*

GIS

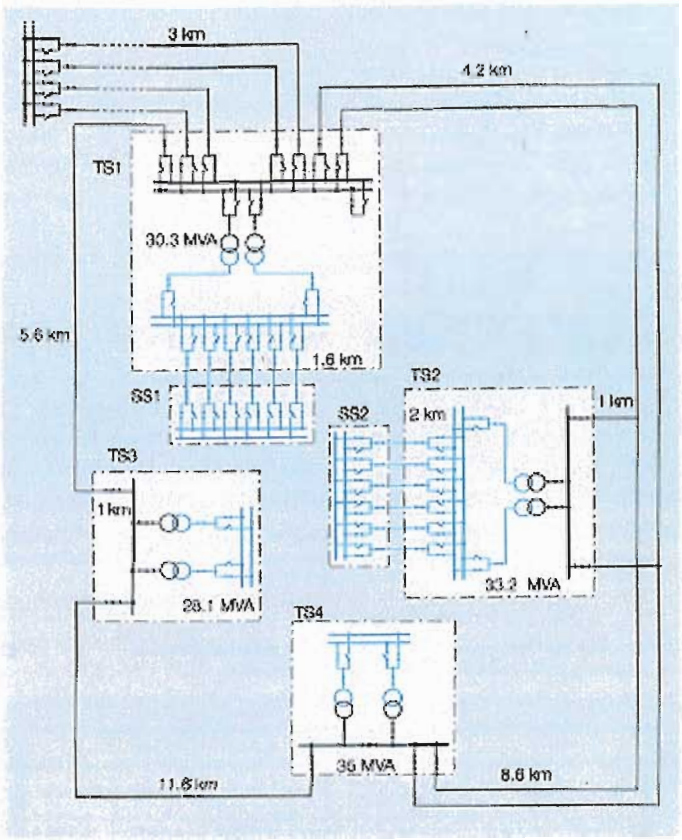
The GIS variant 2 considered in the study consists of three HV transformer substations located in the center of a city. The connection to the surrounding 110-kV network is provided by three cables run from the nearest HV substation to the main substation of the urban HV network. This main substation is configured as a double busbar system, allowing maintenance to be carried out on one busbar without having to de-energize the complete station. The remaining substations in the HV cable ring, which are also located in the city center, are H-type transformer substations with a bus-tie. They also allow maintenance and repairs within the gas compart-

ment on one half of the busbar while the other half remains in operation.

AIS

In the AIS variant 3 there is an overhead line loop around the supply region, the right half of which consists of double lines (due to the load flows). As in the GIS variant, the main HV substation consists of a double busbar system, the remaining HV transformer substations having H-type configurations. Transformer substation TS2 has a double-T connection to the double overhead line, substation TS3 being looped into the single line on the left-hand side. Due to the larger space required, the transformer substations are located in the less densely populated outer regions of the city.

Double lines connect the outer ring to the transformer substations, ie there are two circuits on the same poles. This solution allows efficient utilization of the available space. However, it also reduces the reliability of the HV supply as both circuits can trip for the same reason ('common mode failure', eg due to back-flashover from the earth wire to both circuits caused by lightning striking the earth wire or contact with trees).



AIS variant of the 110-kV network 3

TS1, 2, 3, 4 *Transformer substations 1, 2, 3*
SS1, 2 *Satellite stations 1, 2*

Medium-voltage network

A comparison of the GIS and the AIS variants based only on the differences in the HV network is too limited, since the locations of the HV transformer substations are of decisive importance and exert a large influence on the structure of the MV network. The study therefore takes the load situation in an actual urban network, including the load values and the geographical location of the MV transformer substations, as its starting point 4.

Radial operation of an MV network results in a large number of possible network concepts. Besides differing in terms of their initial capital costs, they also considerably influence operation of the network. Each utility therefore has its own planning rules, according to which the network configuration is adapted to customers' requirements and to the geographic locations of the MV loads.

Planning rules

The technical constraints for each network variant are the allowed voltage band and the limits for the short-circuit power, which are dictated by the rating of the switchgear. There are also some design rules to be formulated:

- Use of standard components:
  - XLPE MV cables with an Al cross-section of 150 mm² (distribution cables) and 240 mm² (transmission cables)
  - 110-kV/MV transformers with a rated power of 31.5/40 MVA
- Open-loop topology for the distribution network. The distribution cables start from the MV busbar of the HV/MV transformer substations, run between customers' substations and are looped back to the MV busbar of the same HV transformer substation. During normal

operation one of the cables in this ring remains open to provide simple protection. Each HV/MV transformer substation has its own back-up transformer, allowing maintenance to be carried out on a transformer without having to operate switches in the MV network.

- Maximum of 14 customer substations in a loop. This limits the number of customers whose power supply would be interrupted in the event of an MV network failure, as only the feeder connected to the HV/MV station busbar is equipped with overcurrent protection and a circuit-breaker.
- Normal loading of the feeder cables, so that a worst-case cable failure (feeder failure close to the HV/MV transformer substation) does not load any cable beyond 120 % of its capacity. The maximum load of 5.2 MVA per cable at 10 kV (10.2 MVA at 20 kV) at the beginning of the planning period takes into account the reduced ampacity for cables bundled in the same cable trench close to the transformer as well as a margin for load growth during the planning period.

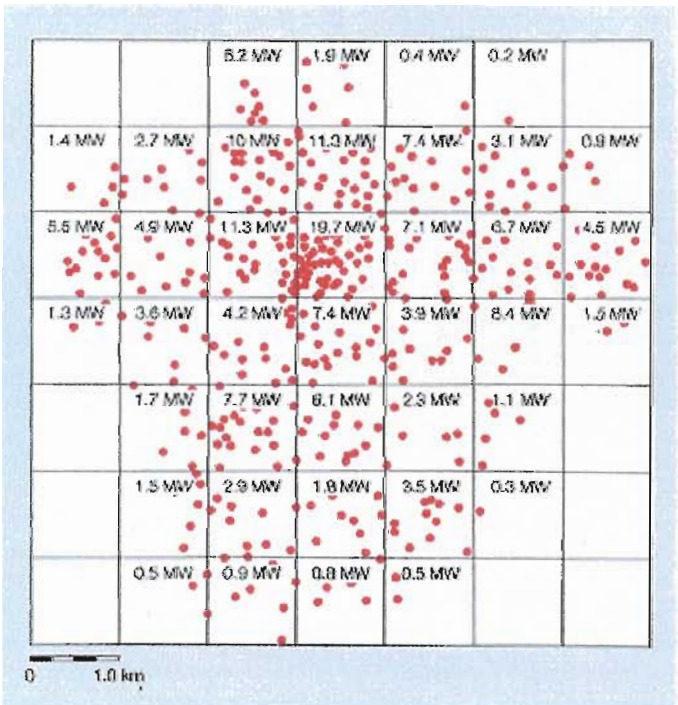
Planning results

The inherent flexibility of GIS allows planners to place the injection points close to the load centers **5**. The first effect of this is on the number of loads considered an optimum for each HV substation, and thus on its installed transformer capacity. Secondly, it reduces the required power transmission capability of the MV network, allowing an additional saving due to the smaller MV cable cross-sections required. And thirdly, transmission losses are avoided. The reduction in operating costs due to this third advantage is especially evident at low distribution voltages.

These general effects are also reflected in the results obtained with the described network solutions. The MV network receiving power from the GIS substations consists of radially operated (open) loops, all of which are fed from the MV busbars of the HV substations.

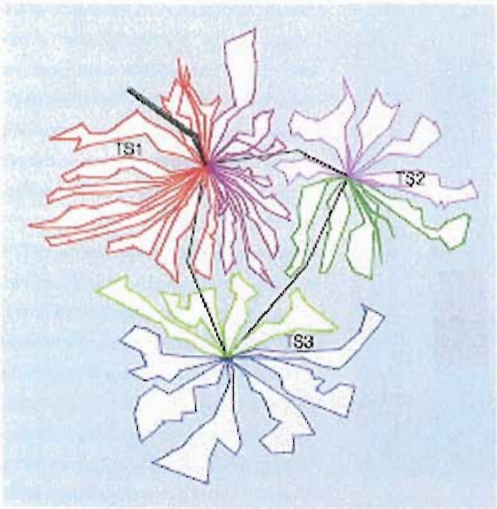
The peripheral locations of the transformer substations in the AIS variant make additional satellite stations necessary **6**. These have remote MV busbars, fed by the HV transformer substations via several parallel and selectively protected transmission cables. Their reliability is comparable with the reliability of the MV busbar of the HV transformer substations, but they call for extra capital investment and cause additional losses. The AIS variant with a voltage of 10 kV requires 6 parallel cables from the HV injection to the satellite station, the 20-kV variant requiring 4 cables. These satellite busbars, like the MV busbars of the HV substations, supply power to the MV substations via open loops.

Distribution and load rating of MV transformer substations taken as a starting point for the GIS/AIS system comparison **4**



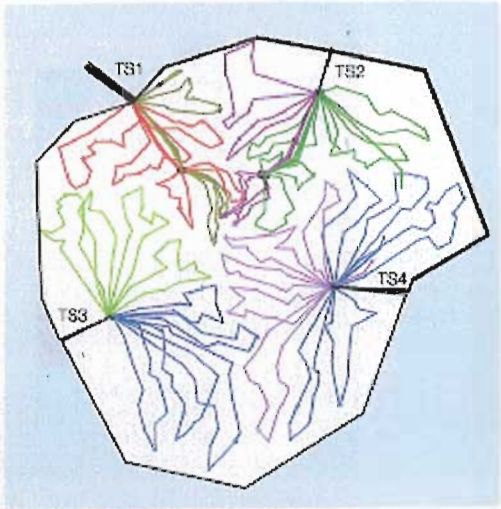
GIS/AIS cost comparison

7 and **8** compare the respective cost of the AIS and the GIS variant (the figures for the different components and external services apply to the German market). An interest rate of 8 % and an inflation of 3 % were assumed for the calculation of the cash values. A load growth of 1.5 % per year (linear) was set and the cash value calculated for a planning horizon of 10 years. It should be noted that planning times of 20 years and more, which have



Topology of the GIS variant with injection points close to the load centers (distribution voltage 20 kV) 5

TS1, 2, 3 *Transformer substations 1, 2, 3*



Topology of the AIS variant with peripheral transformer substations and additional satellite stations (distribution voltage 20 kV) 6

TS1, 2, 3, 4 *Transformer substations 1, 2, 3, 4*

often been used in the past to evaluate different variants, are not realistic in today's rapidly changing market environment.

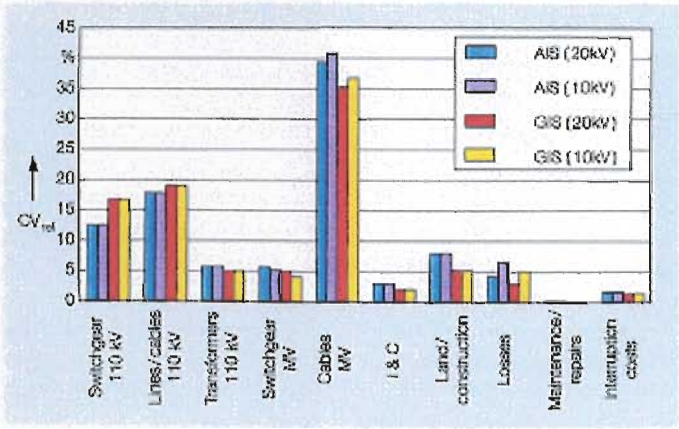
The first cost to be considered in the comparison is that of the HV switchgear installations. This is significantly higher for the GIS than for the AIS solution. However, the difference in system costs is smaller than the difference in component (eg, switchbay) costs. This is because the inherent flexibility of the GIS/cable topology allows the HV network to be configured more efficiently, leading to a smaller number of HV substations (3 for GIS, 4 for AIS) and also switchbays per HV transformer substation.

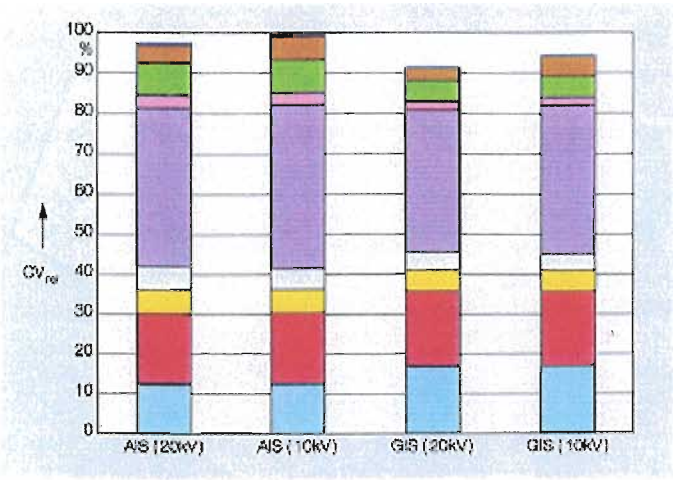
A look at the cost of the 110-kV connections shows a similar picture. Although the cable length in the GIS variant is much shorter than the length of the overhead lines with AIS, the capital cost of the equipment and civil works are higher in the case of GIS.

The difference in the cost of the 110-kV transformers results from the different number of transformers in the two variants. In the case of GIS, two transformers are required at substation *TS1* for normal operation, so that only a single additional unit is necessary for back-up. The AIS variant requires a dedicated back-up unit for the transformer in each HV substation.

Comparison of the cost of the GIS and AIS variants (cash value over a period of 10 years) 7

CV_{rel} *Relative cash value*





Comparison of life-cycle costs with GIS and AIS (cash value over a period of 10 years) 3

CV_{rel} *Relative cash value*

- *110-kV switchgear*
- *110-kV lines/cables*
- *110-kV transformers*
- *MV switchgear*
- *MV cables*
- *I&C*
- *Land/construction*
- *Losses*
- *Maintenance/repairs*

Another factor that speaks for the GIS variant is the cost of the MV switchgear installations. The difference here is due to the additional switchgear panels needed for the satellite stations in the AIS configuration.

The cost of the MV cables is extraordinarily high for both variants (about 40 % of the life-cycle costs/cash value). Their absolute value as well as the difference between AIS/GIS shows how important it is to compare complete supply concepts rather than just the HV substations if results are to be reliable and realistic: HV injection close to the load centers reduces the MV network costs significantly.

The smaller number of HV substations, the absence of remotely controlled MV satellite stations and the reduced number of HV connections also reduce the cost of the secondary equipment (ie, for protection, control and instrumentation) for the GIS variant.

In addition, the cost of the land, foundations and buildings is lower for the GIS variant. This is due to the smaller space required, which can even compensate for the higher cost of land in the inner city. Also, the GIS substation can be integrated in the basement of an existing building, thus providing the required space without having to add to the footprint. Since this solution is still unusual in Germany, it has not been considered in the comparison. In South-East Asia and other regions, utilities often take advantage of this option in order to install HV stations in highly populated load centers.

The difference in the cash value of the losses quantifies the additional transmission loads in the MV network. A saving of approximately 25 % is possible with GIS. It is costs such as these that underscore how much the results depend on the basic assumptions of the comparison, eg the interest rate and the planning horizon. As regards the losses, the short planning horizon chosen for this comparison results in the saving due to GIS being underestimated.

When state-of-the-art AIS and GIS components are used, the cost of their maintenance and inspection will be a minimum. As the comparison shows, the maintenance costs have no impact on the variant ranking. The GIS variant exhibits the lower costs as it needs fewer inspections per switchbay (GIS once every 8 years, AIS once every 5 years), of which it also has fewer.

The final factor in the comparison is the cost of supply interruptions, ie the costs at the load end resulting from interrupted service. Although it is the customer who foots the bill, these costs enable the non-reliability of the network to be defined in monetary terms.

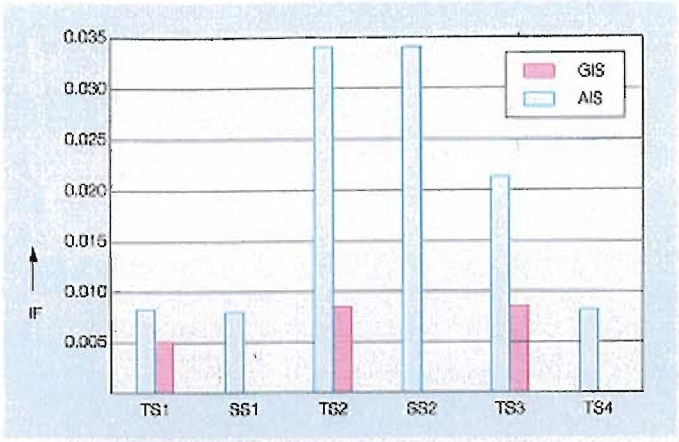
Significant differences also exist between the 10-kV and the 20-kV MV supply. A 20-kV network can, roughly speaking, transfer twice as much power as a 10-kV network over the same cable cross-section. This either reduces the investment in primary equipment (due to the smaller number of MV cables) or leads to lower losses for the same cable cross-section.

This effect is relativized in actual planning. The maximum number of MV substations supplied by the same cable in high load density areas is limited not only by the ampacity of the feeder cables but also by the need to keep the number of customers affected by a single failure as low as possible. Another constraint is due to the open-loop topology: the MV substations must be assigned to two half-loops, each of which starts at the HV substation busbar and is linked to the

other via a disconnect point in the network.

The cost comparison of the GIS and the AIS variant in the case of the 20-kV network shows reduced differences in losses and in the investment in MV cable. However, the costs are still significantly (approx 4 %) higher for the AIS variant.

The direct comparison of the 20-kV and 10-kV variants for similar HV technologies shows an advantage for the 20-kV solution. This result is plausible and in line with actual planning experience.



Interruption frequencies (IF) at the MV busbars of the HV substation 9

TS1, 2, 3, 4 *Transformer substations 1, 2, 3, 4*
SS1, 2 *Satellite stations 1, 2*

Reliability of the AIS/GIS variants

A reliable electric supply is especially important in urban networks where load densities are high and users are sensitive to interruptions. The outage and reclosure behaviour is an area in which there is a fundamental difference between the GIS/cable and the AIS/overhead line solutions, at least as far as the main power users are concerned.

110-kV cable faults are rare, being due in most cases to accidental damage during construction work. Since HV cables are buried deeper than MV cables, the latter, which are laid above them, give them a certain degree of 'protection'. If the HV cable itself is not sufficiently robust (eg, protected by a surrounding steel tube, as in the case of pipeline compression cable) concrete ducts can be used to provide the necessary shielding. This minimizes the failure rate even in supply regions in which large-scale construction work is carried out.

Besides their cost, the main drawback of HV cables is the long time needed for their repair, as HV cables are typically spliced by the supplier's staff.

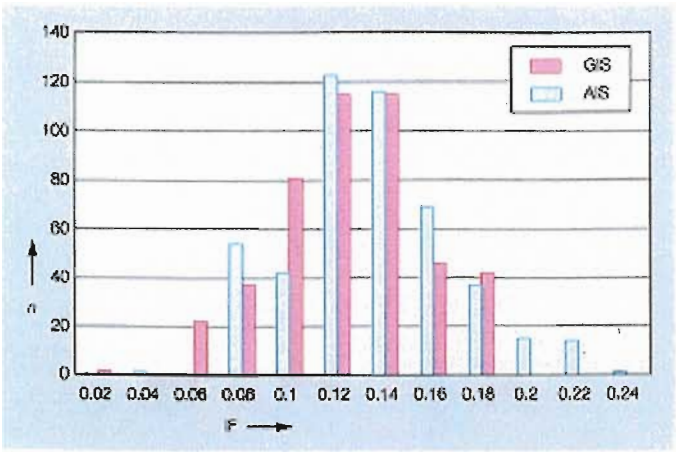
The characteristic behaviour of overhead lines is somewhat different to that of cables. Overhead lines exhibit high outage rates but short outage times. To keep overhead line systems compact, parallel circuits are run on the same pylons. As mentioned before, a single event can therefore lead to common mode failures in which several circuits are tripped. This aspect is important and has to be considered in every reliability comparison.

Table 1 shows the values used in the reliability calculations for the HV lines/cables. The high value for the outage rate is a pessimistic estimate in which the majority of the faults are assumed to be caused by external cable damage. A reliability calculation was performed to quantify the differences between the 10-kV variants of the AIS/GIS concepts. The calculation simulates relevant component failure modes and evaluates and quantifies the consequences for the customers. The component behaviour is derived from statistics about failures in the past.

Table 1:
Reliability data for cables and overhead lines (110 kV)

		Outage[1] rate per year and 100 km	*Repair duration (h)*
Overhead HV line (1 circuit)	*short*	0.21	1
	long	0.04	20.6
Overhead HV line (common mode)		0.15	2.7
HV cables	*short*	0.35	3.4
	long	0.35	298

[1] Independent, stochastic outages



Interruption frequency distribution, as experienced by customers 10

n Number of MV nodes
IF Range of interruption frequencies (per year, upper value)

The results of the calculation are shown in 9. It is evident that the interruption rates are much lower for the GIS/cable variant, although high failure rates for the HV cables have been assumed. The effect on the reliability is felt at the MV busbars of the HV transformer.

The values for GIS are of the order of 0.01 per year, ie one interruption every 100 years. The interruption frequencies for the AIS substations TS1 and TS4 are of the same magnitude, but TS3 and especially TS2 are more frequently affected (by a factor of 3 to 4). The reason is the loop-in via a double overhead line, which has been assumed in both cases, and in addition for TS2 the double-T connection to the surrounding ring (also a double overhead line).

The values for the satellite stations receiving power from TS1 and TS2 are the same as for the MV busbars of the HV transformer substations. This is plausible because of the selective protection provided for the parallel transmission cables between the transformer substations and the satellite stations; neither a single nor multiple cable failure will affect the satellite supply as long as the protection devices work correctly.

As shown in 10, there are no significant differences between the AIS and the GIS variant within the MV network.

The reason lies in the radial operation of the MV loops. Every fault leads to the attached feeder tripping and interrupting the supply to all customers in the same half-loop. This interruption of service is usually ended by (manual or remotely controlled) switching. The large number of events in the MV network compared with those in the 110-kV system dictates the interruption behaviour and ensures comparative reliability at all customer nodes. This effect is underscored by the comparable interruption costs for AIS and GIS 7.

In cases where a special-tariff customer is connected to the HV transformer substation via parallel cables, the reliability of the HV substation is passed on to the customer, who also benefits in this way from the GIS solution.

Conclusions

Although the GIS solution appears initially to be the more costly, its flexibility allows the HV transformer substations to be sited in optimum locations. The number of infeeds from the HV system can be optimized and the transmission load of the MV network reduced. This leads to a significant saving in investment as well as operating costs which more than compensates for the additional cost of the GIS and HV cables.

Another advantage of the GIS/cable combination is that it offers better reliability than the AIS/overhead line solution. Major customers linked to the HV substation via parallel MV cables also experience this in everyday operation. And being inherent advantages of the GIS/cable variant, these benefits cost the network operator nothing.

GIS technology also offers further benefits which are harder to quantify but which can be decisive for the realization of a project. One example is the option of complete integration of a GIS substation in an existing building when no extra site area is available. Summing up, GIS is a cost-efficient, flexible and reliable solution for supply systems in regions with high load densities.

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STATE OF CALIFORNIA
PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

GRAY DAVIS, *Governor*

October 14, 1999

G. L. Pat Ervin
58 The Strand
Hermosa Beach, CA 90254

Subject: Development of Transmission Right of Ways and the Redondo 2000 Proposal

Dear Mr. Ervin:

This letter responds to your letter to me of June 1, 1998 and to the related questions that my staff and I have discussed with you. The existing laws and decisions noted below apply in part, but the California PUC (CPUC or the Commission) is still developing policy in this area. Hopefully this information will assist you.

The questions posed by yourself and by Arlene Pinzler of Senator Bowen's office appear to be:

> How would benefits from the sale of former right of way real estate be divided among ratepayers, regulated utility shareholders, and power plant owners; and
>
> What can be said about proceeds from sale of transmission line right of way (ROW) in Redondo Beach owned by Southern California Edison (Edison), and about sale and conversion of substation property adjacent to the Redondo power plant, which was formerly owned by Edison but sold to AES Corporation?

Sales versus Leasing

While the Commission has approved power plant sales, it has not ruled yet on the sale of utility rights of way (ROW). The Commission has, however, signed 4 decisions in the last year or so to approve leases of ROW. In those cases, for example D.99-04-066 attached, one half of the lease proceeds were credited to ratepayers, and the balance to shareholders.

An issue which the Commission may want to address in response to proposals such as yours is how to accommodate future needs for ROW in the public interest which would be given up in a sale of ROW.

The Public Utilities Code indicates that public utilities may use one another's ROWs. From an environmental point of view, multiple utilities should use the same disturbed areas for their projects, consistent with mutually convenient access and with safety considerations. It may be difficult for other utilities (gas, electric, telephony, water, oil) to align their projects within a ROW that has been permanently conveyed to others for nonutility uses.

Parties, however, currently dispute the effect of this code section. An existing owner of electric ROW for example may emphasize a right to exclude a pipeline-type utility. Since siting a new ROW can be difficult today, owning a ROW of any kind is becoming quite an asset. The issue of shared ROWs has not been litigated yet at the CPUC.

Ratepayer Neutrality versus Net Profit

The second question as you initially posed it assumed that the proceeds from the sale of the utility ROW would pay first for relocating the substation, with any remainder being returned to ratepayers.

While this is one possible outcome, another one is that ratepayers would receive all of the net proceeds from such a sale of assets, which had been held by shareholders to serve ratepayers. In today's merchant environment, if the new unregulated owner of the generating station elected to relocate the adjacent substation, ratepayers might not be obligated to fund such a move.

D.97-09-049 attached, approved a sale of power plants by Edison. All of the proceeds in excess of depreciated book value were credited to ratepayers. Note, however, that all such monies were immediately absorbed by the debt ratepayers still owe the utility, due to restructuring transition costs (also known as stranded costs).

Please contact Brian Schumacher of my staff if you need more information.

Very truly yours

Paul Clanon
Director, Energy Division

cc: Arlene Pinzler, Senator Bowen's office
Brian Schumacher, Energy
Andrew Barnsdale, Energy
Peter Allen, Legal

Attachments: Memo Schumacher to Ervin September 27, 1999
D. 99-04-066 Edison Right of Way Leasing
D. 97-09-049 Edison Generating Plants Sale

Memorandum

To: Pat Ervin

From: Brian Schumacher

Date: September 27, 1999

Re: **Issues Raised by Redondo 2000 ROW Undergrounding Project**

Note: This memorandum consists almost entirely of staff work sent to me and attached here for your additional information.

Below is a brief analysis of the issues presented by the project with respect to current CPUC policies on: ratemaking with respect to sales and leases of utility property; safety and reliability standards; and environmental impact.

Background On ROW Applications

Utilities currently are encouraged to make economic use of properties that they hold as utility property on behalf of ratepayers. While this may have been initiated in the past simply out of good business sense, it certainly has taken on greater significance in the context of industry restructuring. The utilities that remain as distributors, once both transmission and generation functions have been pared away, are under pressure from regulatory agencies nation-wide to make the most of what they still retain, whether it be under COS regulation or PBR regimes. Nationwide studies have been done by utilities to survey "best land uses" for utility property that is retained on behalf of ratepayers. Transmission ROWs are one of the primary foci of this effort. The highest revenue-generating use was found to be private self-storage facilities and these studies have been cited by at least SCE (and perhaps others) in their applications to the CPUC for authority to lease land under their transmission ROWs for exactly such purposes.

All proposals to lease or otherwise encumber electric utility property are subject to Section 851 of the PU Code[1] and IOUs must file an application with the CPUC for approval of such proposals.[2] At least four applications by electric IOUs have been processed and approved by the CPUC for leasing transmission ROWs for private self-storage facilities:

- A.98-02-042 filed by SCE for authority to lease available land on a ROW for a proposed mini-storage facility -- ALJ Wright.

[1] http://www.leginfo.ca.gov/cgi-bin/waisgate?WAISdocID=57399742+0+0+0&WAISaction=retrieve

[2] Note that this may not be the case with "licensing" agreements. Apparently, an IOU can enter into a licensing agreement with a party without filing for Section 851 approval, because such an agreement only lasts for a year and can be revoked at any time by the licensor.

- A.98-05-034 filed by SCE for authority to lease available land on a ROW at three separate sites for proposed mini-storage facilities -- ALJ Wright.
- A.98-07-018 filed by SCE for authority to lease available land on a ROW for a proposed mini-storage facility -- ALJ Stalder.
- A.98-07-019 filed by SCE for authority to lease available land on a ROW for a proposed mini-storage facility -- ALJ Stalder.

In each case cited above, the Commission issued a decision granting the leasing authority sought. For example, Application 98-07-019 (above) was resolved by Decision 99-04-066 on April 22, 1999. CEQA was not triggered in any of these cases and no environmental review was conducted by the CPUC because SCE showed that a discretionary CEQA review of each of these projects would be required and undertaken by another public agency at a local level prior to the final project approval.

Ratemaking Treatment

With respect to ratemaking treatment for leases approved under Section 851 for the above-cited Applications: revenues were split 50/50 between the ratepayers and the IOU shareholders under their new PBR. A future proceeding at the CPUC will further allocate the ratepayers' share.

With respect to ratemaking treatment for sales approved under Section 851, revenues would be split depending upon whether the sale took place before the end of the electric restructuring transition period, and whether the proceeds from the sale of that asset would be viewed as being tied to the need to reduce Transition Costs. However in the decisions to date approving the sale of power plants[3]:

- The proceeds above book value from the sale belong to ratepayers; and
- Proceeds were conveyed to ratepayers by reducing the balance owed in the Transition Cost Balancing Account.

Policy Issues

The Redondo 2000 proposal raises the following issues:

- An application would be required by the CPUC under Section 851 of the PU Code for authority to sell utility-held property.
- If the ROW in question is owned and operated by a Transmission Owner the jurisdiction might fall to FERC or another state agency.

[3] D.97-12-107 in A. 96-11-046 for PG&E approved sale of Morro Bay, Moss Landing and Oakland plant to Duke. D. 99-04-026 approved sale of Potrero, Pittsburg and Contra Costa plants to Southern Power Company. 100% of the gain on sale in fossil plant divestitures applied to stranded cost recovery (transition costs) to be paid for by ratepayers.

- The CPUC 851 review would require CEQA review on a site-specific basis, at a minimum, and possibly raise global "policy" questions concerning the state-wide impacts of approving large numbers of such proposals, and therefore trigger a more global "program-level" CEQA review.
- Ratemaking issues would have to be dealt with here at the CPUC under the Section 851 proceeding. In addition, issues regarding any outstanding environmental liabilities associated with the property would need to be resolved.
- Safety issues would also need to be addressed in such a proceeding. Current applications for IOU leasing of ROW lands for projects such as self-storage have built-in agreements that preserve the IOU's rights with respect to access, safety, reliability, emergencies, and other performance issues necessary to the IOU's obligation to ratepayers and the public. The implications for General Order 95 governing overhead lines would need to be reviewed.
- Other broad policy issues would need to be addressed:
  - What about other utilities already co-located in the ROW corridor?
  - What about other utilities planned to be co-located in the ROW corridor?
  - Environmental implications of privatizing ROWs and thereby limiting future potential ability to co-locate other utility projects within the ROW corridor?
  - Is there a value to having future land corridors dedicated to linear facilities given that there is clearly a value to having existing land corridors so dedicated?[4]
  - What are the implications of encouraging heavy-densities of building and population around buried underground transmission corridors (safety, EMF)? In addition, some of these ROW corridors may even be included in County and City General Plans as being "open space" or "green ways".

[4] One of the railroads' biggest assets was its right-of-way. With development encroaching on the natural environment and the implications of linear damage becoming increasingly evident (linear disturbances break up habitat into non-sustainable areas without enough carrying capacity), existing linear ROWs are really becoming a very valuable asset.

ALJ/BRS/sid

Mailed 4/22/99

Decision 99-04-066 April 22, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for Authority to Lease Available Land to Instant Storage on Transmission Line Right of Way.	Application 98-07-019 (Filed July 8, 1998)

OPINION

Summary

This decision authorizes Southern California Edison Company (Edison) to lease a site along its Barre-Ellis transmission line in the City of Westminister to Instant Storage, for the purpose of operating a self-storage facility. The revenue generated by the lease will be shared between ratepayers and shareholders.

Background

In this application, Edison seeks a Commission order authorizing it to lease to Instant Storage a 5.48-acre site located on its Barre-Ellis 220-kilovolt transmission line right of way near Bolsa Avenue in the City of Westminster. Instant Storage will develop and operate a self-storage facility on the site.

Edison proposes that this application be categorized as ratesetting, and anticipates that hearings will not be necessary. The issue, according to Edison, is as follows: Is the proposed lease of this available land on Edison transmission line right of way to Instant Storage adverse to the public interest?

There are no protests to the application and no party has requested a hearing in this matter.

Study of Secondary Uses

Edison conducted a survey in 1990 of secondary use policies of nine utilities across the nation, which identified four possible uses for the unused portions of their operating properties: auto parking, recreational vehicle storage, equipment storage, and self storage. Of these uses, self storage offered the highest level of potential revenues from this type of site.

Edison filed Advice Letter 1286-E pursuant to Rule VII.F of the affiliate transactions rules set forth in Appendix A of Decision (D.) 97-12-088. Appendix B of Advice Letter 1286-E identified the secondary use of transmission line right of way as a category of existing products or services and listed storage facilities as existing within that category. Edison believes that this filing complies with Rule VII for existing non-tariffed products and services.

The Lease

The terms and conditions of the lease are set forth in the proposed lease agreement, which grants Instant Storage the option to lease the site for development as a self-storage facility. The initial term of the lease is 10 years, and may be renewed for three additional 10-year terms. The agreement provides for an expected base revenue lease fee of $82,182 in year one, $122,273 in year two, and $164,364 in year three through the tenth year. The base lease fee will be adjusted upon each renewal option based on the then fair rental value of the property less the value of Instant Storage's improvements. The adjusted base lease fee will not be less than the fee otherwise payable immediately prior to the adjustment, and will not exceed an increase of 2% per year compounded annually for 10 years.

An additional lease fee applies at the end of each year, based on gross revenues over the base lease fee for the same year.

The revenues from this lease will be substantially higher than revenues obtained from the current lessee, Bolsa Nursery, which uses the site for horticultural purposes. Bolsa Nursery is planning to relocate and license another Edison property, but if its current license remained in effect, it would generate revenues of only $10,960 per year.

Lessee's activities may not interfere with the operation of Edison's transmission facilities that cross the site, and hazardous substances, explosives or flammable materials may not be stored or used on the site. Specific clearances must be maintained between electrical conductors, tower legs and steel and wood poles. Lessee is required to maintain adequate access roads for Edison's use.

Edison retains the right to enter the site at all times, to impose temporary restrictions, to occupy and use the site to perform necessary work, and retains the right of eminent domain or inverse condemnation. Edison has the right to approve construction plans and specifications and to review the selection of a general contractor for the development project.

Instant Storage is responsible for all taxes and fees levied against the site and improvements thereon, and for obtaining all necessary permits. It must maintain appropriate insurance and agrees to indemnify Edison against all normal liability claims relating to the site.

Ratemaking Treatment

All of the revenue from the proposed leases will be treated as OOR. Under presently authorized ratemaking treatment for OOR, Edison will record 50% of the revenues from these leases in the Secondary Land Use Revenue (SLUR) Memorandum Account pending a final disposition of the ratepayers' share of such revenues. Disposition of the SLUR Memorandum Account is being addressed in Edison's Application (A.) 97-06-021, filed on June 12, 1997, which

seeks approval of a new OOR sharing mechanism for the gross revenues received from the enhanced utilization of utility assets, including leases of available land. Accordingly, the Commission will order Edison to file an advice letter adding the leases that are the subject of this Application to the SLUR Memorandum Account until the Commission issues a decision on Edison's proposed revenue-sharing mechanism in A.97-06.921.

On January 30, 1998, Edison filed Advice 1286-E which set forth proposed categories of non-tariffed products and services offered for sale by Edison and provided descriptions of the existing products or services within each category. This Advice filing was made pursuant to Rule VII.F of the Affiliate Transactions Rules contained in Appendix A of D.97-12-088. Attachment B to Advice 1286-E identified to the Secondary Use of Transmission Right of Ways and Land as a category of existing products or services and listed storage facilities as an existing product or service within that category.[1] This filing complies with the requirements of Rule VII for existing non-tariffed products and services.

Valuation of the Barre-Ellis Site

Edison compared the fees negotiated for this site in relation to comparable self-storage facilities in Southern California as a function of the effective gross income of the facility. The annual base fee from this facility will be approximately 20% of the project gross revenues, which is within the acceptable market range and is in line with the rental income Edison will receive from the leases approved by the Commission in D.96-12-024, D.97-07-009 and D.97-07-010.

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[1] We grant authority in this decision for the lease sought by Edison in its application. We do not address Advice Letter 1286-E in this decision.

Selection of Developer

Instant Storage was selected based on its development expertise and the self-storage background of the company's partners. The company began business operations in 1978 as a recreational vehicle and mini-storage company. One of the partners is also a partner in Industry Storage, with which Edison has also entered into a proposed lease for self-storage agreement and has filed Application (A.) 98-07-018 seeking Commission authority.

Discussion

Under Public Utilities (Pub. Util.) Code § 851, no public utility "shall...lease...[property] necessary or useful in the performance of its duties to the public...without first having secured from the commission an order authorizing it so to do." The relevant inquiry for the Commission in Section 851 proceedings is whether the proposed transaction is "adverse to the public interest." (See, e.g., Universal Marine Corporation (1984) 14 CPUC2d 644.) In D.93-04-019, the Commission observed that "Joint use of utility facilities has obvious economic and environmental benefits. The public interest is served when utility property is used for other productive purposes without interfering with the utility's operation or effective service to utility customers." (Id., at 3.)

This proposal will achieve that result, and the level of revenue will be substantially higher than that achieved from the former lessee, benefiting both ratepayers and the utility. The conditions in the proposed lease adequately protect Edison against interference with its operations by the lessee.

Edison notes that the revenue from the previous lease on this site was credited to the OOR account, and suggests the same ratemaking treatment for this lease.

That policy was established by the Commission in D.96-12-024 dated December 9, 1996, in approving a lease similar to this one. That decision ordered

Edison to preserve a 50/50 sharing of revenue between the utility and ratepayers, by crediting all the revenues to Edison's OOR Account 454.611 (Secondary Land Use), with Edison's 50% to be credited to the utility, and the ratepayers' 50% placed in a memorandum account until further order of the Commission. Currently, that memorandum account, the SLUR Memorandum Account is being addressed in Edison's A.97-06-021, filed on June 12, 1997, which seeks approval of a new revenue sharing mechanism for gross revenues received from enhanced utilization of utility assets, including leases of land.

Pending further Commission action on the ratemaking issue, we will direct Edison to deal with these revenues in the same manner.

In Resolution ALJ 176-2997, dated July 23, 1998, the Commission preliminarily categorized this proceeding as ratesetting, and preliminarily determined that hearings were not necessary. No protests have been received. Given this status, a public hearing is not necessary, nor is it necessary to alter the preliminary determination in ALJ 176-2997.

We conclude that the proposed lease is in the public interest and should be authorized promptly to obtain the benefits as soon as possible.

Environmental Matters

Under the California Environmental Quality Act (CEQA), the Commission is obligated to consider the environmental consequences of a project that is subject to the Commission's discretionary approval. (Public Resources Code § 21080.) A project is an activity that "may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment" and either (a) is directly undertaken by any public agency, (b) is supported by contracts, grants, subsidies, loans, or other forms of assistance from one or more public agencies, or (c) involves the issuance of a lease, permit,

license, certificate, or other entitlement for use by one or more public agencies. (Public Resources Code § 21065.)

Pursuant to this statutory directive, Commission staff from the Energy Division Environmental Review Team have engaged in discussions on both the applicability of CEQA to the projects proposed in Edison's application and the potential environmental impacts that might reasonably be foreseen for such projects. Based upon these discussions and its independent assessment of the proposed project, staff has determined that the proposed projects, in their entirety, have the potential for direct or indirect physical changes to the environment which are reasonably foreseeable. Therefore, staff has determined that an environmental review of the projects proposed by Edison in the instant application, and for which a discretionary approval for a leasing agreement is sought by Edison from the Commission, is required pursuant to CEQA prior to implementation of the proposed projects.

Although the leases at issue are for self-storage uses, development of the properties by the lessee is subject to all applicable laws and, before any use or development will be permitted, discretionary approvals from other public agencies having jurisdiction will be required. This discretionary approval process will also trigger application of CEQA.

This issue is presented whether the necessary CEQA review is performed by the Commission or by another state or local authority. CEQA guidelines expressly recognize that the timing of CEQA review "involves a balancing of competing factors," and that such review should occur" as early as feasible in the planning process to enable environmental considerations to influence project program and design and yet late enough to provide meaningful information for environmental assessment." (14 Cal.Code Regulations § 15004.)

In this case, the Commission will defer to the appropriate state and local authorities having jurisdiction over any proposed changes in use of the site. These authorities are generally in a superior position to evaluate local environmental impacts and develop appropriate mitigation strategies.

Such deference is appropriate under the circumstances here and will not result in any regulatory gap. CEQA specifically applies to discretionary projects such as issuance of conditional use permits and approval of tentative subdivision maps. (See Pub. Res. Code § 21080; see also Myers, supra, 58 Cal.App.3d at 424.) Accordingly, if and when there are more developed proposals to change the uses of the sites, the appropriate state and local authorities having authority over such proposed uses must conduct environmental review under CEQA.

Furthermore, in lieu of conducting CEQA review at this time, the Commission may condition its approval of the proposed leases on lessee's compliance with all applicable environmental regulations. Such conditional approval is commonly imposed and is consistent with Commission precedent under CEQA. (See Sundstrom v. County of Mendocino, 202 Cal.App.3d 292, 308 (1988), citing Perley v. Board of Supervisors, 137 Cal.App.3d 424, 429 (1982); see also in Re: SpectraNet SGV, D.97-06-020, Cal.PUC LEXIS 367 at *37 (1997).)

Due to these circumstances, staff reports that it has concluded that no further environmental review pursuant to CEQA will be required for the approval of this application by the Commission because such an environmental review will be required and conducted by local jurisdictional authorities in their discretionary approval of local permits required for the subsequent later actions necessary to develop the property at issue in this application. Staff's report dated November 16, 1998 addressed to the Administrative Law Judge for this proceeding and a supporting letter from Edison to staff dated August 17, 1997 are on file in this proceeding.

Waiver of Comment Period

Pub. Util. Code § 311(g)(1) provides that this decision must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

All parties in the proceeding have stipulated to waive the 30-day waiting period required by Pub. Util. Code § 311(g)(1) and the opportunity to file comments on the draft decision. Accordingly, this matter will be placed on the Commission's agenda directly for prompt action.

Findings of Fact

1. Edison is an electric public utility subject to the jurisdiction of the Commission.

2. Edison has a site on its Barre-Ellis transmission line right of way available for secondary uses.

3. Edison has entered into a proposed lease with Instant Storage, subject to Commission approval, which would result in substantially greater revenues from the lease than were achieved from the prior lessee.

4. The proposed lessee, Instant Storage, has experience in self-storage facilities.

5. Instant Storage will finance, construct, and maintain the self-storage facility, bearing the costs, and making payments to Edison.

6. All of the revenues from the lease will be treated as OOR. Under presently authorized ratemaking treatment for OOR, Edison will record 50% of the revenues from this lease in the SLUR Memorandum Account pending a final disposition of the ratepayers' share of such revenues.

7. The proposed project, in its entirety, has the potential for direct or indirect physical changes to the environment which are reasonably foreseeable; however,

lessee's plans to build are presently preliminary and contingent upon numerous factors.

8. CEQA review will be performed by the appropriate local authority.

9. There are no protests or requests for hearing.

Conclusions of Law

1. The proceeding has been designated as ratesetting; no protests have been received; no hearing is necessary.

2. Joint use of utility property when practical offers economic and environmental benefits.

3. CEQA review is deferred to the appropriate state and local authorities having jurisdiction over proposed changes in use of the site.

4. The proposed leases are not subject to further review under CEQA by the Commission.

5. Edison should be authorized pursuant to Pub. Util. Code § 851 to lease a 5.48-acre site located on its Barre-Ellis transmission line right of way in the City of Westminster.

6. Edison should be ordered to credit the revenues as received to the OOR account with a 50/50 split between ratepayers and shareholders.

7. This decision should become effective on the date signed.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized to enter into a lease of 5.48 acres of its Barre-Ellis transmission line right of way to Instant Storage, under the terms and conditions set forth in the application.

2. As received, all revenues from the lease shall be credited to Edison's Other Operating Revenue Account 454.611 (Secondary Land Use), with 50% credited to Edison, and 50% placed in the Secondary Land Use Revenue Memorandum Account for ratepayers until further order of the Commission.

3. Edison shall notify the Director of the Energy Division in writing of any substantial amendments to, extension of, or termination of the lease agreement, within 30 days following the execution of such amendments, extensions, or termination.

4. Edison shall file an advice letter adding the leases that are the subject of this application to the Secondary Land Use Revenue Memorandum Account.

5. Approval of this lease is conditional upon compliance by lessee with all applicable environmental regulations.

6. The authority granted in Ordering Paragraph 1 shall expire if not exercised before December 1, 1999.

7. This proceeding is closed.

This order is effective today.

Dated April 22, 1999, at San Francisco, California.

RICHARD A. BILAS
President
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

COM/PGC/RB1/sng

Decision 97-09-049 September 3, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the matter of the application of Southern California Edison Company (U 338-E) for authority to sell gas-fired electrical generation facilities.	Application 96-11-046 (Filed November 27, 1996)

I N T E R I M O P I N I O N

Summary

Southern California Edison Company (Edison) requests authority, pursuant to Public Utilities (PU) Code Section 851, to auction and sell 12 fossil-fuel electric generation plants by the end of 1997.

The first interim decision that Edison requests is that the Commission (a) find that Edison's gas-fired generating units are not necessary or useful in the performance of its duties to the public; (b) find that Edison's proposed divestiture will not impair the reliability of electric supply;[1] (c) find that Edison's proposed auction procedures are reasonable and will determine the market price of the plants to be divested; (d) find that Edison need not entertain post-auction overbids; (e) find that Edison's divestiture as proposed is reasonable and the proposed operations and maintenance contract is reasonable under PU Code Section 363; (f) approve Edison's proposed ratemaking treatment of the sale; and (g) find that the sale will not require an environmental impact report under the California Environmental Quality Act (CEQA).

For the next phase, in a second interim decision, Edison requests that we decide whether the proposed form of agreement for certain of the plants between the buyers

[1] Edison moved on February 21, 1997 to exclude any issues associated with the terms and conditions of the form of Master Must Run Reliability Agreement (MMRA, formerly referred to as the Local Reliability Dispatch Agreement) from the first interim decision. That motion was granted by the assigned administrative law judge (ALJ) on February 27, 1997.

and the Independent System Operator (ISO) should be required, consistent with PU Code Section 362, as a condition of sale.

For the third and final phase, in a final decision, Edison requests that we approve the sale if we determine that the auction was conducted in accordance with the approved auction procedure.

We will permit Edison to commence an auction of the plants, which will be subject to our final review and approval upon review of definitive agreements following the auction. However, Edison may not accept final bids until we have completed our environmental review by approving a mitigated negative declaration[2] and the Federal Energy Regulatory Commission (FERC) has approved the form of agreement to be used by ISO (without respect to unit-specific terms).

Procedural Background

Edison filed its application on November 27, 1996. Notice appeared in the Daily Calendar on December 4, 1996. A prehearing conference was held on January 8, 1997. President Conlon, as the assigned Commissioner,[3] issued a ruling (ACR) to establish a procedural schedule on February 11, 1997. An evidentiary hearing was convened on March 17, 1997, at which it was determined that no triable issues of fact existed with respect to the issues that Edison requested be determined in the first interim decision.

On March 28, 1997, Edison, the Coalition of California Utility Employees (CUE) and Southern California Gas Company filed a stipulation, generally as follows: (1) there are no disputed issues of material fact regarding the need for the Alamitos, Huntington Beach, El Segundo, Etiwanda, Mandalay, and Redondo plants to be designated as must-run stations, subject to the MMRA, in 1998 (the parties agree that such stations are needed); (2) the Independent System Operator (ISO) will designate must-run requirements for any period thereafter; (3) the Commission may find pursuant to PU Code Section 362 with respect to local reliability issues that facilities needed to maintain

[2] This is expected to occur after September 25, 1997.
[3] Commissioner Bilas was subsequently co-assigned.

the reliability of the electric supply will remain available and operational (but the parties reserve their rights in the event that the ISO designates any different set of stations as must-run for 1998); (4) there are no disputed issues of material fact that the six must-run (subject to the MMRA) and six non-must run stations can be divested without impairing achievement of planning and operating reserve criteria in 1998 (thereafter the ISO will have sole responsibility); (5) MMRAs will be required for the must-run plants in the Asset Sale Agreement (which will also require that the Power Exchange, as a condition of closing the sale of the plants, have taken certain steps); and (6) with respect to whether the transmission upgrades proposed in Application (A.) 96-11-047 will reduce the number of needed must-run stations, the ISO will make that determination.

On April 14, 1997, the Office of Ratepayer Advocates (ORA) and the Independent Energy Producers Association (IEP) each filed a response to the stipulation, commenting that the stipulation should not be treated as in any way establishing the boundaries of the authority of the ISO.[4] On April 17, 1997, the assigned ALJ ruled that because no party identified a factual issue that it contested, the issues for a first interim decision should be submitted on the briefs of the parties, which were filed concurrently on May 1, 1997, and reply briefs, which were filed on May 9, 1997. On May 1, 1997, Edison moved to make the first interim decision effective immediately. On June 9, 1997, Edison moved to set aside submission of the record for the first interim decision, due to a change in the manner in which Edison proposes to auction plants. Edison now proposes to auction the power plants not classified as must-run singly or in any combination, rather than in pre-determined groups. The assigned ALJ issued a ruling on June 11, 1997, and permitted parties to submit a single round of supplemental briefs on this issue. ORA and IEP filed supplemental briefs on June 20, 1997.

[4] CUE filed a reply on April 29, 1997, expressing its agreement that the stipulation should not be applied expansively or in a manner that would predetermine the Commission's decision on the adequacy of the MMRA form.

Description of the Application

Edison wishes to offer for sale 12 electric generation plants:

- Alamitos Generation Station
- Cool Water Generating Station
- Ellwood Energy Support Facility
- El Segundo Generating Station
- Etiwanda Generating Station
- Highgrove Generating Station
- Huntington Beach Generating Station
- Long Beach Generating Station
- Mandalay Generating Station
- Ormond Beach Generating Station
- Redondo Generating Station
- San Bernardino Generating Station

That wish is consistent with our Decision (D.) 95-12-063, as modified by D.96-01-009, in which we required Edison to submit a plan to voluntarily divest itself of at least 50% of its fossil generating assets. (*Order Instituting Rulemaking/Investigation on the Commission's Own Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation,* mimeo. at 223.) The 12 plants have a combined summer generating capacity of 9,562 megawatts, which is all of Edison's gas-fired generation capacity. Edison proposes to transfer:

(a) real property owned by Edison on which the plants are located,

(b) related real property leases,

(c) easements appurtenant to owned or leased property,

(d) equipment used to conduct plant operations,

(e) spare parts, office supplies and other inventories on hand at closing (except for backup fuel oil supplies),

(f) Edison's interest in written contracts relating to each plant,

(g) Edison's interest in any transferable and separable licenses or permits used in connection with the operation of a plant,

(h) books, records, instruction manuals and other documents relating to the operation of each plant,

(i) third-party warranties specifically relating to assets being transferred,
(j) Edison's interest in any prepayments made by Edison prior to closing
(k) Edison's interest in certain specified air pollution control credits related to the plants being sold
(l) specified additional real property which may not be currently used in plant operations but which is adjacent to or related to a plant
(m) Edison's interest in and right to receive mail relating exclusively to plant ownership or operations, and
(n) other miscellaneous assets as described in the bid documents

Edison will specifically exclude the following property in the bid documents:
(a) fuel oil storage tanks and related property used for backup fuel operations or for the business of Edison Pipeline & Terminal Co. (EPTC),
(b) transmission equipment, switchyards, and radial transmission lines,
(c) communications equipment and facilities used in Edison's transmission and distribution systems,
(d) claims for refunds including refunds of real estate taxes, arising out of pre-closing periods,
(e) proprietary materials (*e.g.*, trademarks, proprietary computer software, marketing materials, trade names), subject to Edison's granting the buyer a fully paid-up, royalty-free license to use certain software exclusively for plant operations,
(f) personnel and employment records related to plant operations,
(g) rights under Edison's insurance policies,
(h) rights to receive mail relating to excluded assets or excluded liabilities,
(i) rights respecting computer hardware that is proprietary to Edison,
(j) specified additional real property not currently used in plant operations but adjacent to or related to a plant,
(k) inventories of natural gas and other fuel and related agreements,

(l) assets constituting working capital, including cash, securities, rights to refund and similar assets,

(m) rights under transactions between Edison and its affiliates, under employment contracts, under collective bargaining agreements, and under contracts related to the purchase or sale of electric power,

(n) customer data, and

(o) other miscellaneous assets ancillary to plant ownership and operation.

Edison plans to sell the 12 plants by a competitive open-auction bid process in three stages. Edison plans to identify and contact potential bidders in the first stage, prior to our decision, to determine whether potential auction participants meet minimum qualifications. Qualified participants would be asked to enter into a confidentiality agreement preventing unauthorized disclosure of certain information.

In the second stage, following our decision, bidding on the plants would occur, consisting of receipt of nonbinding expressions of interest for the purpose of identifying a short list of bidders to be given approximately six weeks to conduct due diligence and prepare formal bids. During that time, bidders would have the opportunity to request changes to the transaction documents which might include, for example, adjustments to the property boundaries of the plant sites. On receipt of binding bids, Edison would review the bids, and either accept one or more bids or solicit further bids from one or more bidders.

In the third and final stage, Edison would enter into definitive agreements with the winning bidders, subject to our final review and approval to determine whether the auction had been conducted in accordance with the approved procedure.

Applicable Legal Standards

Section 851

No public utility may transfer its property that is necessary or useful in the performance of its duties to the public without first having secured the Commission's authorization. (PU Code § 851.) The plants are presently used to generate electricity for delivery to Edison's system. Therefore, the plants are presently useful in

the performance of Edison's duty as a public utility, and PU Code Section 851 applies. Because we are asked to approve the sale this year, Edison's request that we find the plants to be not useful or necessary is premature, since Edison will continue to have the duty as a public utility to generate electricity, at least through the end of this year. (*See In the Matter of the Application of Southern California Edison Co.*, D.95-11-026.) With respect to all property associated with the plants that Edison proposes to exclude from the auction, we will require in our final decision that Edison either file an application to sell all such property pursuant to PU Code Section 851 or file an application to retain the property, pursuant to PU Code Section 377 (including appropriate evidence of market valuation). Edison may amend its application in this proceeding to identify the portions of such property that it proposes to be excluded from this requirement as non-generation related. We encourage Edison to sell as much of its property related to the plants as possible.

Section 362

In proceedings pursuant to PU Code Section 851, we must ensure that "facilities needed to maintain the reliability of the electric supply remain available and operational, consistent with maintaining open competition and avoiding an overconcentration of market power." (PU Code § 362.) "In order to determine whether a facility needs to remain available and operational, the [C]ommission shall utilize standards that are no less stringent that [sic] the Western Systems Coordinating Council and North American Electric Reliability Counsel standards for planning reserve criteria." (*Id.*) The parties refer to such facilities as "must-run."

One of our main concerns in reviewing the sale of the plants is market power. In addition to the dimension of locational market power, which is encompassed by "maintaining open competition," we are also greatly concerned that the sale promote increased competition in the entire wholesale and retail energy market, which is partially encompassed by "avoiding an overconcentration of market power." In the second interim opinion, we will focus on the role of the agreements with the ISO in maintaining open competition. When we know the results of the auction, we will be in a

position to determine whether the outcome raises any overconcentration issue or other market power concern.

We caution all bidders that in making our final determination, we will not approve any sale that merely changes the identity of the possessor of market power from Edison to another entity.

Section 363

PU Code Section 363 requires our approval of an operations and maintenance agreement (O&M Agreement) that provides for the selling utility or an affiliate or successor to operate and maintain plants that are sold for at least two years. We are to require such contracts to be reasonable for both the buyer and the seller.

Section 377

PU Code Section 377 provides that we "shall continue to regulate the nonnuclear generation assets owned by any public utility prior to January 1, 1997, that are subject to [C]ommission regulation until those assets have been subject to market valuation in accordance with procedures established by the [C]ommission."

CEQA

CEQA applies to discretionary approvals of activities that may cause a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment and that are undertaken by a person who receives contracts, grants, subsidies, loans, or other forms of assistance from one or more public agencies or the issuance of a lease, permit, or other entitlement for use. (Public Resources Code § 21065.) Such activities are termed "projects."

Because a purported transfer of utility property that is useful or necessary to the performance of the utility's duties requires our prior approval pursuant to PU Code Section 851, our approval is an "entitlement for use."

On August 25, 1997, the Commission's Energy Division issued a notice of the Commission's intent to issue a mitigated negative declaration. Comments will be received by September 25, 1997, at which time it will be possible to know if all of the potential adverse environmental effects of the transfer of the plants can be avoided or reduced to a non-significant level by imposing appropriate conditions on the transfer. It would be inappropriate for Edison to accept final bids until the specific environmental mitigation measures that may be required are known and approved by a decision by this Commission, because the resulting uncertainty would have a natural tendency to depress bid prices.

Reliability of the Electric Supply

Because of the PU Code Section 362 duty of the Commission to "ensure" the availability and operation of must-run facilities, we assign the burden of proof to parties who assert that a particular facility should not be classified as must-run. Edison presented evidence, that no party disputes, to show that six of the facilities[5] will be needed neither for local voltage support nor to meet applicable planning reserve criteria, and Edison has met its burden.

For the remaining six plants,[6] there is no dispute that they should be treated as must-run for purposes of PU Code Section 362, although the parties also recognize that the ISO may reach a different conclusion in the future. We will take up the means by which those plants are to be ensured to remain available and operational, consistent with maintaining open competition, in our second interim opinion, and in our final opinion we will consider whether such means are consistent with avoiding an overconcentration of market power and other market power concerns. No transfer of the plants can take place until we have concluded that the proposed condition of sale that would make the six must-run plants subject to a contract with the ISO is adequate

[5] Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, and San Bernardino.
[6] Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo.

to ensure that such plants remain available and operational in a way that is consistent with our resolution of market power issues.

ORA suggests that we permit the auction of the non-must-run plants to proceed as soon as CEQA review permits, but to delay auction of the other plants until the FERC has finally approved the form of agreement with the ISO. This is a sound recommendation because it will reduce uncertainty for the buyers as to the exact obligations that will be imposed for the must-run plants. We will not permit Edison to accept final bids for the must-run plants until the FERC has approved the form of agreement with the ISO.[7]

Reasonableness of Proposed Sale Process

Bundling of Plants

ORA and the IEP each are generally supportive of Edison's application. Each criticized Edison's original proposal to offer plants only in four bundles of plants, rather than permitting bidding on single plants or any combination of plants. Following Edison's decision to modify its proposal by unbundling the sale of five of the plants that are not classified as must-run, IEP now argues that the Commission should not permit any bundling for the remaining units, either, because the marketplace is a superior means of determining which plants should be kept together. On balance, the reasons against bundling are more convincing than the reasons for, although it is a close question, and we believe that the bidders should be free to bid on plants singly or in any combination.[8]

Edison gives several reasons why it should be permitted to bundle the must-run plants: Sale of the plants singly could lead to thin bidding, because bidders would concentrate on a few plants, so that bundles would help assure that every plant

[7] We recognize that, in light of the current status of proceedings before the FERC, a substantial delay in the bidding may result from this restriction.

[8] Subject to the likelihood that we will not approve any sale to related entities that results in 40% or more of the capacity offered in this sale being transferred.

receives a bid; facilitating bidding consortia will substitute for permitting single-plant bidding; bundling will maximize sale prices because it will assure operational efficiencies by grouping together plants that can best be run by a single operator; and bundled bidding will reduce transactional costs. Finally, Edison notes that adjustments to the bundles may be necessary depending on feedback from potential bidders.

The only evidence offered on this point consisted of the prepared testimony of Edison's witness Craver and IEP's witness McClary. Since the parties did not identify conflicting factual statements in the testimony of the two witnesses, there was no examination of the witnesses concerning their qualifications, and it is not clear that either witness is an expert in auctions of electric utility generating plants or similar fields. In any event, however, neither witness purports to deliver an expert opinion that one method of auction will yield superior results to another. Rather, each witness marshals the arguments of his party in support of or opposition to the proposal. As stated above, we find the arguments in favor of unbundling more persuasive.

Bid Evaluation

ORA suggests that Edison should be required to disclose its bid evaluation methodology in advance so that bidders would know how the various bid scenarios (overlapping bids, etc.) would play out before making their bids. This, however, is an area in which uncertainty tends to increase, rather than depress, the proceeds to be expected. It is not customary for sellers and their investment bankers to disclose such methodologies in advance, because doing so eliminates any possibility of receiving a premium.

Minimum Bids

ORA suggests that Edison be required to prepare a minimum bid amount that could be used under some circumstances if it were suspected that the winning bid were too low because of a flawed auction. Edison opposes use of a sealed minimum bid.

The auction serves a purpose apart from reducing Edison's market power through divestiture (to whatever extent it does reduce Edison's market power). That purpose is a market valuation of the plants. A properly conducted auction that results

in a completed sale will determine market valuation in the most direct manner possible. (At a minimum, properly conducted auction would be one in which the property to be sold has been actively exposed to potential buyers, the qualified buyers have been given equal access to relevant information about the property, all buyers are bidding on the basis of the same transaction documents, and the procedures for receiving bids are known in advance to all participants. In short, it is a fair process in which all potential buyers vie in competition. That competition gives assurance that the price arrived at is an objective one.) A minimum bid, by contrast, would represent merely an estimate of market value. In the absence of evidence that bidding at the auction as designed will necessarily be too thin to determine market value, we will not require a minimum bid. Edison's retention of the right to reject bids in the event of irregularities in the auction process and our own final review provide adequate assurance that plants will not be divested as a result of an auction process that failed to produce serious bids.

Air Emissions Credits

ORA proposes that we should require Edison to sell the plants separately from certain tradable emission credits that have been granted to Edison under two air quality management programs for the reduction of sulfur dioxide and nitrogen oxides. ORA believes that selling the credits separately will increase the amount realized for them and lead to the correct ratemaking treatment for such credits.[9] Edison acknowledges that some of the credits for sulfur dioxide are in excess of the foreseeable operational requirements for the plants.[10] However, Edison argues, the emissions credits are required to operate the plants and if a potential bidder had to acquire such rights separately, the likely result would be a lower bid on the plants to reflect the cost of acquiring such rights. Both parties note that the optimum auction strategy to

[9] ORA argues that revenues from the sale of excess air emission credits should be refunded to ratepayers by way of the Electric Rate Adjustment Mechanism balancing account. However, because such credits are clearly a generation-related asset, it is appropriate to treat them through the transition cost recovery mechanism provided by AB 1890.

maximize the combined value of the plants and emissions credits is conjectural because neither party has presented a thorough economic analysis of the topic.

We see no principled reason to require the separate sale of emissions credits if we are not also going to require the plants to be sold in their component pieces. Presumably, the whole is greater than the sum of its parts and a better price can be obtained by offering the plants as a going concern with the required emissions credits than can be acquired by offering the plants without such credits. However, we will require in our final decision for Edison to file an application pursuant to PU Code Section 377 or 851 for any emissions reduction credits not sold in the auction.

Whether the Proposed Sale Process will Result in Determining the Fair Market Value of the Plants

Aside from the dispute concerning bundling, which we believe should be resolved in favor of auctioning the plants in any combination, the suggestion that bid evaluation criteria should be published, which we believe is unwise, and the proposal for a sealed minimum bid, which we will not require, no party disputes that the proposed sale process, upon consummation, will result in determining the fair market value of the plants absent some significant irregularity. No party contests Edison's request that post-auction overbids[11] should be prohibited, and we agree.

We are troubled, however, by Edison's reluctance to preclude proposed changes by bidders to the precise terms of the contractual documents, and we will carefully consider any claims by losing bidders of any prejudice that may have resulted from a winning bid that was conditioned upon such changes.

Proposed Operations and Maintenance Agreement

Only one disputed issue concerning the O&M Agreement exists. ORA recommends that we require Edison to establish a subsidiary to provide services under

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[10] For that reason, Edison is not including all of the sulfur dioxide emissions credits in the auction.

[11] Bids received following the close of the auction that offer a higher price than received from the highest bidder.

the proposed O&M Agreement so that the resources used for such services can be distinguished from Edison's continued regulated maintenance services. Edison argues that it will be required, in any event, to track generation-related operations and maintenance costs separately from those costs that it will continue to collect in rates, so that a separate subsidiary is not necessary for that purpose. In addition, Edison argues, a separate subsidiary would involve additional costs for setup and corporate maintenance. We agree with Edison that ORA has not shown that the benefits of placing these services in a separate operating unit would justify the costs.

Whether the Proposed Accounting and Ratemaking Treatment Should be Approved

No party disputes Edison's proposed accounting and ratemaking treatment of the sales. (However, the question related to the cost of incremental capital additions to the plants is being handled in a different proceeding.)

As described in the application, Edison proposed to deduct the costs of sale[12] from the sale proceeds to obtain net sale revenue. If net sale revenue for any plant is less than the sunk costs of that plant (as determined in A.96-08-001 *et al.*), Edison would seek recovery of the difference as an additional recoverable transition cost through a debit to its Transition Cost Balancing Account proposed in another proceeding. If greater, Edison would credit the Transition Cost Balancing Account.

Edison will adjust net sale revenue upwards or downwards to account for all tax consequences.

Edison proposes to retain the station fuel oil tanks[13] and their associated potential environmental liabilities. It proposes to collect any costs incurred with respect to environmental liabilities consistent with the Settlement Agreement between the

[12] Including, but not limited to, investment banker fees, attorney fees, consultant fees, title reports, permits, and filing fees. These would be recorded in Edison's previously approved Divestiture of Fossil Generation Memorandum Account.

[13] These provide a back-up fuel oil storage capability should natural gas delivery be disrupted.

Division of Ratepayer Advocates[14] and Southern California Edison Company in Application 93-07-029 (dated March 28, 1994), Attachment B, adopted by the Commission in D.94-10-044.

Through the Hazardous Substance Clean-up and Litigation Cost Balancing Account established in D.94-05-020, Edison proposes to recover its cost of remediation for certain existing and identified environmental conditions at the sites of the plants, as well as accrued third-party tort claims and remediation obligations resulting from release of hazardous toxins into the atmosphere or water courses, in respect of electric and magnetic fields, currently unknown environmental conditions, and any other costs of environmental remediation that may be required in the event that any third party seeks to hold Edison directly liable for environmental conditions subsequent to the sale of a generation facility. However, we recently directed that no new generation-related amounts be recorded in such accounts. (D.97-08-056.) Accordingly, Edison should be permitted to amend its application to propose another treatment.[15]

Edison proposes to record all workforce management costs for reasonable worker protection benefits for workers who are impacted as a result of the proposed transfer to the Divestiture of Fossil Generation Memorandum Account until such time as its Transition Cost Balancing Account is approved, when such costs would be recorded to an appropriate subaccount in the Transition Cost Balancing Account.

Because the proposed O&M Agreement provides for Edison to be paid its fully-loaded direct labor and allocated indirect costs, Edison does not propose to establish any special ratemaking for the costs and revenues associated with the O&M Agreement.

Edison is retaining portions of the plant sites for possible future sale. It is premature to make any determination of the treatment such transactions should receive. With respect to tradable emissions credits, Edison expects that the value of the

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[14] Now ORA.

[15] If such treatment differs substantially from the treatment proposed by Pacific Gas and Electric Company in A.96-11-021, Edison should explain the reason for such difference in detail.

credits for nitrogen oxides will be fully reflected in bids. For sulfur dioxide credits, however, most of the stations were allocated a substantial surplus compared to their operating requirements. Edison proposes either to sell the retained allowances in separate transactions or to retain them for use in connection with Edison's coal-fired generation. At such time as the surplus credits are either sold or retained, the consequences can be addressed (but such proceeds must ultimately be offset and included in the Transition Cost Balancing Account). As noted previously, for both surplus property including fuel-oil facilities and inventories (except property that Edison shows to be non-generation related) and credits, we will require an application pursuant to PU Code Section 377 or 851.

Findings of Fact

1. Edison is an electric utility subject to the jurisdiction of the Commission.

2. The Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, San Bernardino, Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants are presently used in the performance of Edison's duties as a public utility.

3. It is reasonable to permit Edison to commence an auction, but Edison should not be permitted to receive final bids until we have adopted a mitigated negative declaration.

4. Edison has designed an auction process that will, absent significant irregularity, establish the market value of the Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, San Bernardino, Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants, upon sale of those plants, if bidders are permitted to bid on any combination of plants.

5. No party disputes Edison's proposed accounting and ratemaking treatment of the sales.

6. No reason appears to require the O&M Agreement to be performed by a subsidiary of Edison.

7. The O&M Agreement is reasonable to Edison and the buyer.

8. For purposes of PU Code Section 362, the Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, and San Bernardino plants will be needed neither for local voltage support nor to meet applicable planning reserve criteria.

9. For purposes of PU Code Section 362, the Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants are needed to maintain the reliability of the electric supply until the ISO determines otherwise.

Conclusions of Law

1. The sales of the Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, San Bernardino, Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants are subject to PU Code Section 851.

2. In proceedings pursuant to PU Code Section 851, we must ensure that facilities needed to maintain the reliability of the electric supply remain available and operational, consistent with maintaining open competition and avoiding an overconcentration of market power.

3. We should determine whether the Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants remain available and operational in a subsequent decision, prior to the consummation of any sale of those plants.

4. The sales of the Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, San Bernardino, Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants are consistent with the policies underlying D.95-12-063, as modified by D.96-01-009, and expressed in Assembly Bill (AB) 1890 (1996 Stats. ch. 854).

5. The auction of the plants will upon sale, absent some significant irregularity, determine the market valuation of the plants.

6. We should permit Edison to commence an auction of the Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, San Bernardino, Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants, but Edison should not be permitted to receive final bids until we have adopted a mitigated negative declaration.

7. The sale of the plants should be made subject to the O&M Agreement.

8. If the plants are sold, Edison's proposed accounting and ratemaking treatment of the sale of the plants should be approved, subject to confirmation of net book value of the plants in A.96-08-001 *et al.* and to the prohibition contained in

D.97-08-056 against recording generation-related costs to the Hazardous Substance Clean-up and Litigation Cost Balancing Account.

9. Edison should be permitted to amend its application with respect to the generation-related costs that it proposed to be recorded in the Hazardous Substance Clean-up and Litigation Cost Balancing Account.

10. No post-auction overbids should be permitted.

11. Our final decision should consider whether the sale of the plants is in the public interest, with special attention to market power issues and the fairness of the auction procedure.

INTERIM ORDER

THEREFORE, IT IS ORDERED that:

1. Southern California Edison Company (Edison) may commence an auction of the Cool Water, Ellwood, Highgrove, Long Beach, Ormond Beach, San Bernardino, Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants, but shall not receive final bids for any of the plants until further order of the Commission approving a mitigated negative declaration and, for the Alamitos, El Segundo, Etiwanda, Huntington Beach, Mandalay, and Redondo plants, an order of the Federal Energy Regulatory Commission approving the form of agreement with the Independent System Operator for the operation of those plants. Edison shall permit bids on any combination of plants.

2. The sale of the plants shall be subject to conditions that we may require (a) to avoid or reduce to non-significant levels any adverse environmental impacts that we may determine will arise from physical changes reasonably foreseeable in connection with the transfer of the plants and (b) in connection with ensuring the continued availability of must-run plants consistent with maintaining open competition and avoiding an overconcentration of market power.

3. If the plants are sold, the sale shall be subject to the Operations and Maintenance Agreement in the form proposed in the application.

4. If the plants are sold, Edison may apply the accounting and ratemaking treatment described in this application to such sales, subject to confirmation of net book value of the plants in Application (A.) 96-08-001 *et al.*, and to the extent not inconsistent with Decision (D.) 97-08-056. Edison may amend its application with respect to the generation-related costs that it proposed to be recorded in the Hazardous Substance Clean-up and Litigation Cost Balancing Account.

5. If the plants are sold, Edison shall not consider post-auction overbids.

6. Edison may amend its application in this proceeding to establish what portion, if any, of each plant site is non-generation-related. For all unsold portions of the existing plant sites and other generation-related assets (such as emissions reduction credits), Edison shall either file an application pursuant to PU Code Section 851 for the sale of such assets, or file an application to retain such assets pursuant to PU Code Section 377.

This order is effective today.

Dated September 3, 1997, at San Francisco, California.

GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L NEEPER
RICHARD A. BILAS
Commissioners