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REAL TIME SENSORS IN GEOTHERMAL FLUIDS, THEIR COSTS AND BENEFITS

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INTRODUCTION

Geothermal fluids in the United States are heavily loaded with a variety of chemical species[1-6] which can accelerate or depress corrosion, precipitate as scale to foul piping and heat exchanger surfaces, cause gas formation and produce other undesirable effects. In many cases, these factors (if unidentified on a real time basis) can cause unwanted shutdown and loss of income to the user of the energy contained in the fluid. Researchers at Pacific Northwest Laboratory (PNL) operated by Battelle for the U.S. Department of Energy have been studying the development of sensors for geothermal monitoring and evaluating process options for their use. This program has lead to potential plant reliability improvement with the associated reduction in outage time.

The overall mission of the program is to "develop Field Tested Electrical and Electrochemical Sensors and Test Apparatus for in situ characterization of Geothermal Fluids and transfer this technology to users so that user needs can be met." The value of the development effort and the installation of suitable real time sensors to identify potential problems and prevent unwanted or non-routine shutdown is an important but not adequately discussed part of the work.

We intend to elaborate on the costs and benefits of using real time sensors. To do this we will provide a summary of the PNL effort, a background discussion on geothermal power plants, and a discussion of several cases where problems were identified and in some cases prevented. Cost factors, savings and benefits-costs to the sponsor will be summarized and brief conclusions concerning the benefits of having real time instrumentation installed in the power plant will be characterized.

PNL PROGRAM DESCRIPTION

The geothermal instrument development program[8-20] is a multifaceted effort to evaluate and develop sampling methods, identify materials compatability and corrosion information and develop instrumentation which can be used to evaluate the in situ chemistry of geothermal water. The chemical sensors and instrumentation which have been developed for the purposes of real time evaluation of geothermal process streams are shown in Table 1.

The evaluations have been carried out at Magma Corporation's 10 MWe, East Mesa Binary Cycle power plant under a cooperative program between PNL, Magma Electric Corporation and the U.S. Department of Energy. Essentially, Magma has provided appropriate access at various locations in the process piping systems for installation of instrumentation and other apparatus. PNL has provided the services needed to install, monitor and evaluate the geothermal fluid using instrumentation and sampling methods developed in the program. Evaluation of sensor performance is also being completed as a part of the effort. Funding for the PNL work is provided by the U.S. Department of Energy and has been underway for several years. The cases described in the following section identify the value of the program to Magma and other users. An essential part of the effort is to ensure that the data obtained from the sensors can be properly interpreted and used to prevent unwanted failure or shutdown.

TABLE 1. Sensors Being Developed at PNL

SENSOR	STATUS
Reference Electrode	Field Test
Conductivity Cell	Field Test
pH Sensors	Laboratory Test
Sulfide Ion Sensor	Discontinued
Co_2 Sensor	Uncertain
Linear Polarization Probe	Field Test
Corrosion Probe	Field Test

BACKGROUND

GEOTHERMAL ENERGY SYSTEMS

Geothermal systems may be classified into two categories according to the physical state of the pressure controlling phase.[2] The first and most common are hot water systems, such as Cerro Prieto (Mexico) and Wairaki (New Zealand), where liquid water is the continuous pressure controlling fluid phase. Vapor may be generated as a steam phase as the pressure drops during production from the wells. A few geothermal systems including Larderello (Italy), Matsukawa (Japan), and the Geysers (California), are in the second category, characterized by dry, superheated steam with little or no associated liquid.

Because of these resource differences, two types of power generating equipment are used. Where dry steam is available or water can be flashed to steam, condensing steam turbines are normally used. The system (Figures 1 and 2) is very similar to that used on conventional power plants, and works reasonably well if the steam is of good quality, has a relatively small permanent gas content, and is relatively noncorrosive.

Where medium temperature not water (up to 200°C) is available, the vapor-turbine cycle has been developed to take advantage of more favorable thermodynamic factors and reduce or eliminate the mineral scales that are produced when water is flashed to steam. In the latter process, the hot water is brought to the surface at sufficient pressure to maintain it as a liquid and passed through a series of heat exchangers where the heat is transferred to boil a working fluid and superheat the resulting high density vapor (Figure 3). This high density vapor is then expanded through a turbine to produce power and then flows to another heat exchanger where it is cooled and returned to the boiler. Practical and economic advantages of this process are believed to be significant because the largest share of the United States (and world) geothermal resource is in systems which have temperatures below 200°C (392°F) where this process is most efficient. A schematic of the vapor-turbine cycle is shown in Figure 4.

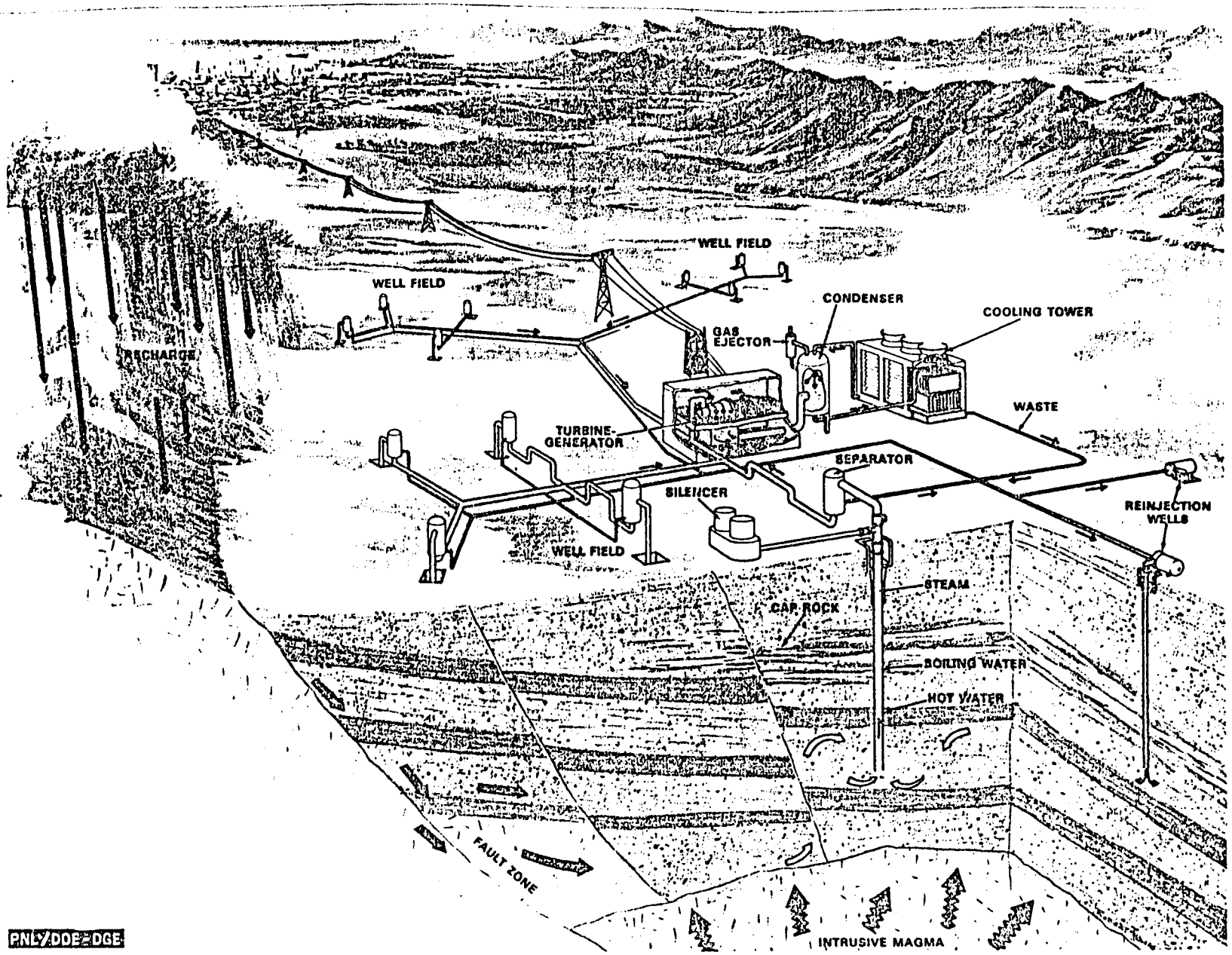

FIGURE 1. Flash Steam Geothermal Power

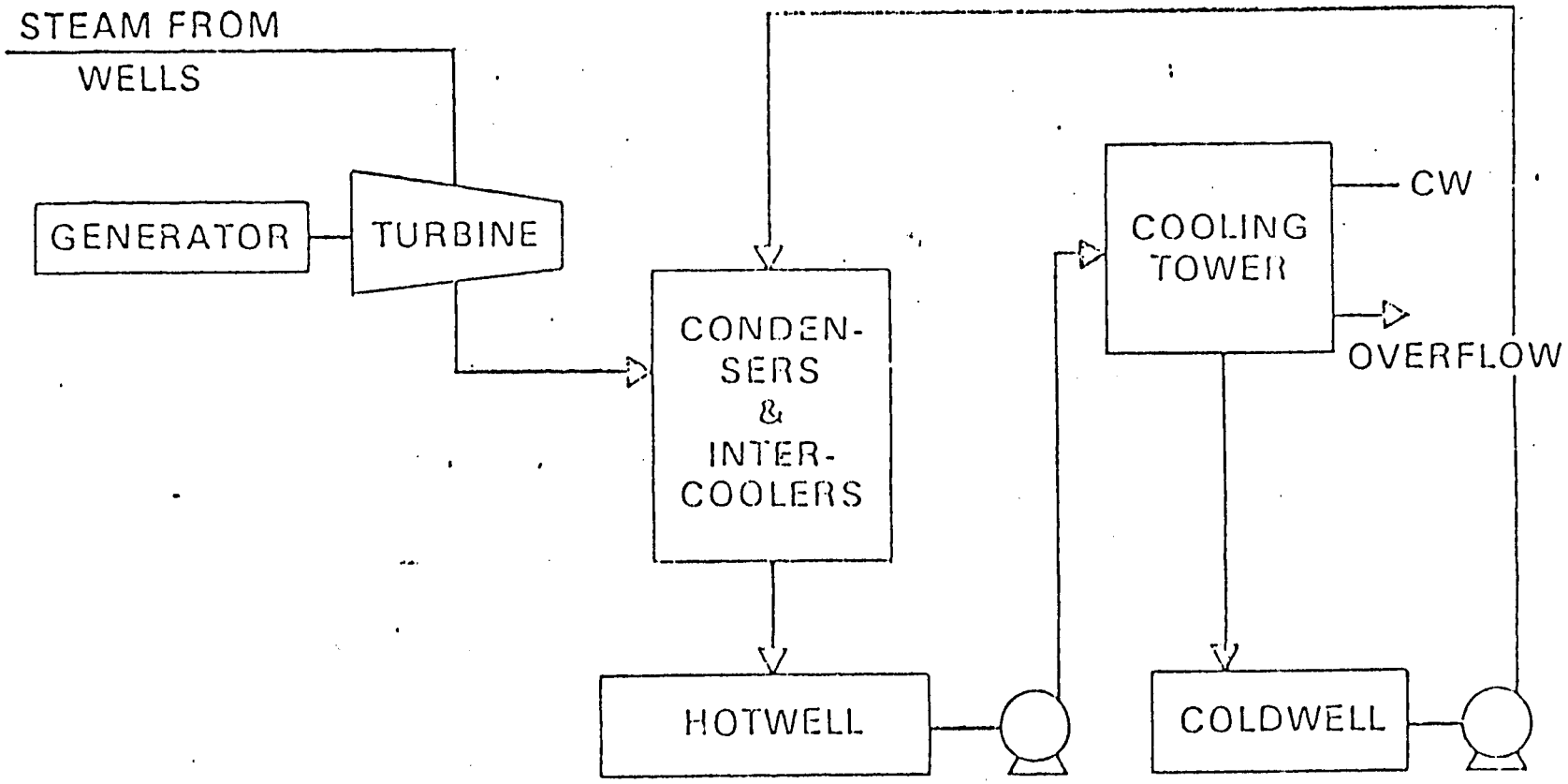

FIGURE 2. Typical High Temperature Geothermal Power Cycle

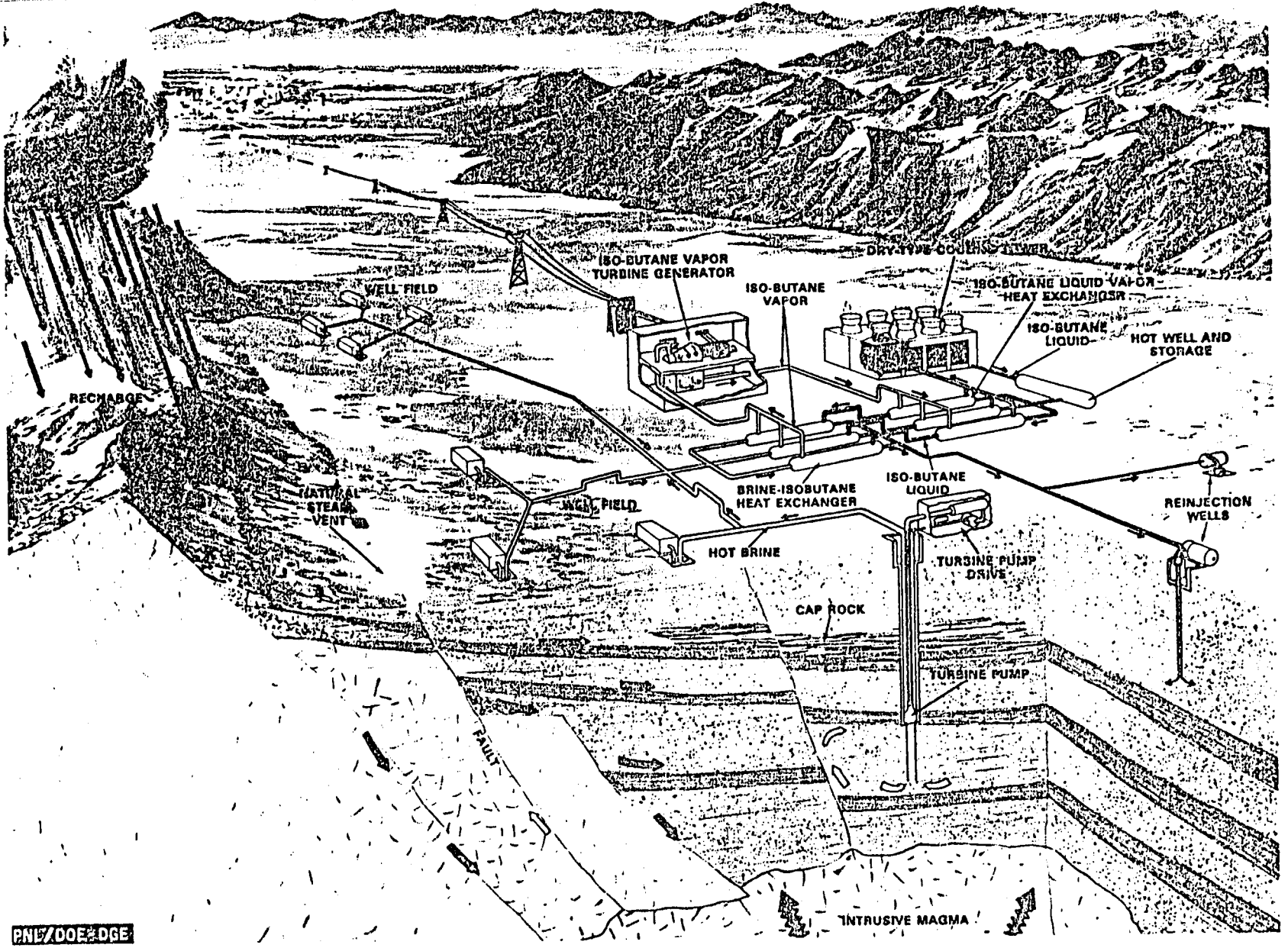

FIGURE 3. Vapor-Turbine Binary Cycle Geothermal Power

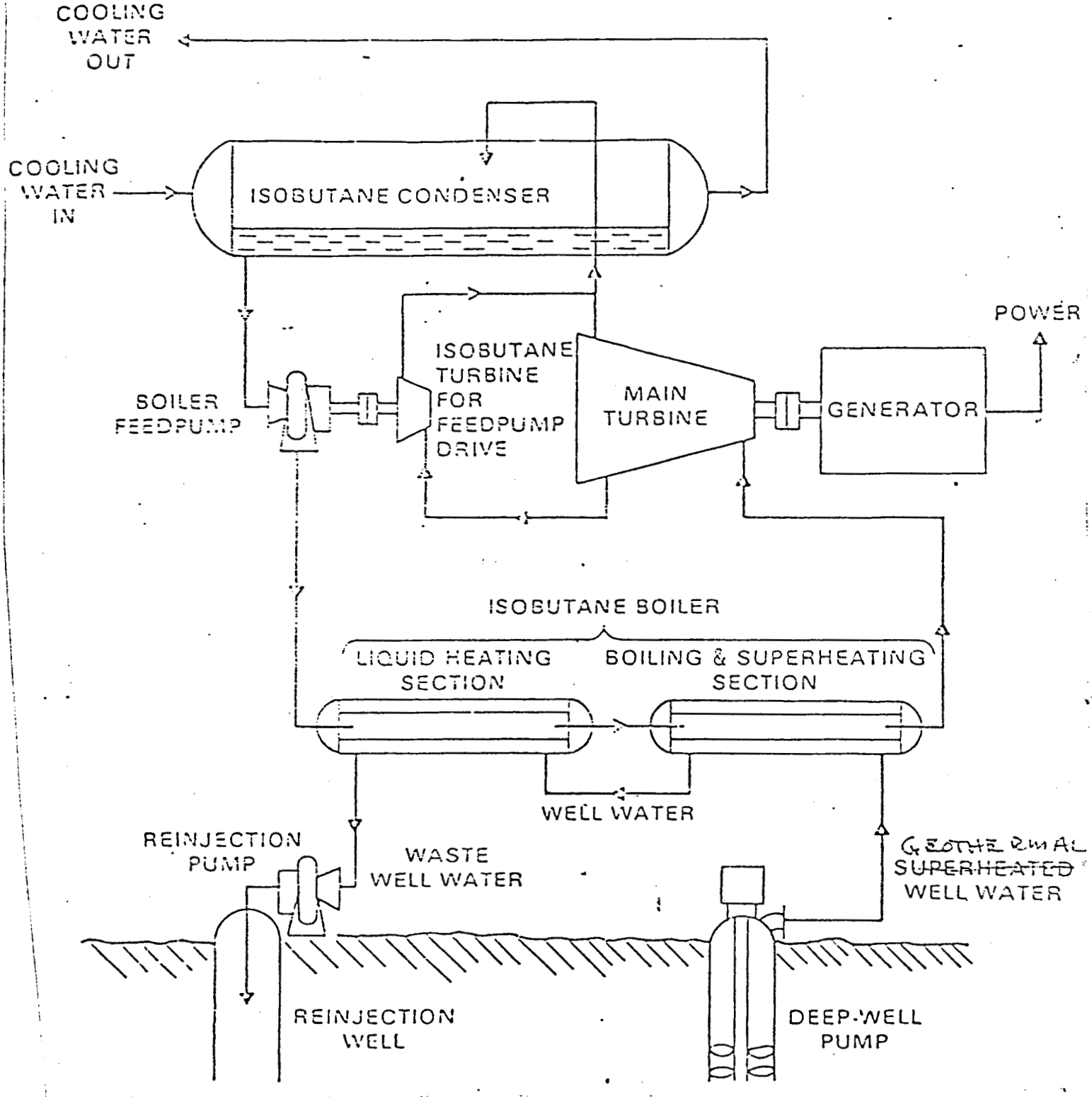

FIGURE 4. Typical Medium Temperature Vapor-Turbine Cycle Diagram

A variety of working fluids can be used in the vapor-turbine power cycle. Isobutane is a working fluid with the right thermodynamic characteristics and promising economics for power generation in binary cycle systems operating below 177°C (350°F). Freon® and propane can be used at lower temperatures. Isopentane can be added to isobutane to adjust the working properties. These working fluids usually does not cause a corrosion problem, but the primary geothermal fluids can cause severe corrosion and scaling. Unwanted flashing and premature gassing also affect system performance and heat transfer.

GEOTHERMAL BRINES

Chemical species found in geothermal brines can accelerate or depress corrosion, precipitate in the system causing fouling, decrease flow rates, generate gas and have other undesirable effects. Table 2 shows the ranges of

TABLE 2. Typical Geothermal Brine Compositions[7]

Species	Normal Range, ppm	Maximum, ppm
Total Dissolved Solids	1,000 - 10,000	360,000
Chloride	100 - 1,000	260,000
Sodium	100 - 1,000	87,000
Sulfate	50 - 500	84,000
Calcium	10 - 100	65,000
Magnesium	1 - 10	40,000
Potassium	50 - 140	30,000
Aluminum	0.5 - 5	7,200
Iron	1 - 10	4,600
Silica	50 - 500	1,060
Ammonium	0.5 - 5	1,050
Nitrate	Not estimated	1,020
Carbon Dioxide	0.5 - 5,000	500
Lead	0.5 - 5	110
Hydrogen Sulfide	Not estimated	75
Silver	Not estimated	2

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important species in geothermal brines based on data accumulated by a number of authors.[5,6,7]. Data taken from a variety of wells also show that there may be major differences in composition even within the same field. Many brines contain a minimum of dissolved salt (approximately 500 parts per million) whereas others (in the Salton Sea area) may contain more than 300,000 ppm. Some liquids contain primarily sodium and calcium chlorides with some silica, while others have high concentrations of many elements, including transition metals, heavy metals, sulfur, boron and arsenic.

Compounds that precipitate, are usually found as scales and may not show up as a major component in solution. Calcium carbonate and silica scales are common. Calcium precipitation is extremely sensitive to fluid acidity and carbon dioxide concentration, as well as to brine pressure and temperature. Other common brine precipitates include barium compounds, basic iron chloride and metallic sulfites. Careful analysis is required for these species as are evaluations of the effect that pH, carbon dioxide, temperature, and pressure have on their solubility. Unfortunately for most analyses a sample is obtained at the source and the the analysis completed in the laboratory. Thus, no real time analysis is obtained.

Plant operators must have accurate knowledge of the geothermal fluid chemistry at operating temperatures to optimize operation, prevent corrosion, increase equipment service life, and maximize profit and system use. An attractive alternative to sampling with its inherent problems, is instrumentation, which can continuously measure the various chemical species and properties of geothermal fluids on a real time basis and be used to monitor events which can produce unwanted potentially catastrophic or other failure. Electrochemical sensors that have been available do not survive at the temperatures encountered in goethermal fluids. Others are needed. PNL's program is an attempt at rectifying this situation.

PNL developed sensors have successfully detected butane leaks and/or changes in chemical composition of fluids at the Magma Corporation's 10 Megawatt Power Plant at East Mesa California prior to unexpected plant shutdowns. Repairs and shutdown time resulting from component failure could have been reduced substantially and in two cases was prevented by early use of information provided by the sensing equipment.

CASE HISTORIES AND BENEFIT-COST OF CHEMICAL INSTRUMENTATION

The following are case histories where information obtained from instrumentation developed at PNL[8-20] either prevented unwanted catastrophic failure and unwanted shutdown or could have been used to do so had a rapid and correct interpretation of the data been available to plant operators. In each case history[21] a description of the event will be presented and the benefit-cost of the instrumentation in preventing the failure will be estimated. The benefit-cost calculation presented here is an extremely simplified approach and does not consider the time value of money, discount rate, or other economic factors which are normally evaluated. Although simplified, it does illustrate the value which can accrue by using corrosion control instrumentation.

CASE I - SULFURIC ACID INJECTION INTO COOLING WATER LINE

Early on the morning of February 4, 1980 the corrosion probes showed a doubling of iron corrosion rate and a rapid increase of the corrosion rate of copper as seen in Figure 5. Evaluation of the data enabled operators to identify the problem as the sulfuric acid injection pump used for pH control had failed to shut off when shutdown was initiated February 2. Water was being siphoned from the pond through the main water pumps, which were off, and the heat exchanger. Thus, acid was introduced into the heat exchanger system at a higher than normal rate. Because the problem was identified early, corrective measures could be taken. The system was flushed with fresh water and no real damage was done. Consequently, an unwanted shutdown was prevented.

To estimate the benefit-cost of this example the following evaluation was made based upon estimated costs and benefits accrued to Magma.

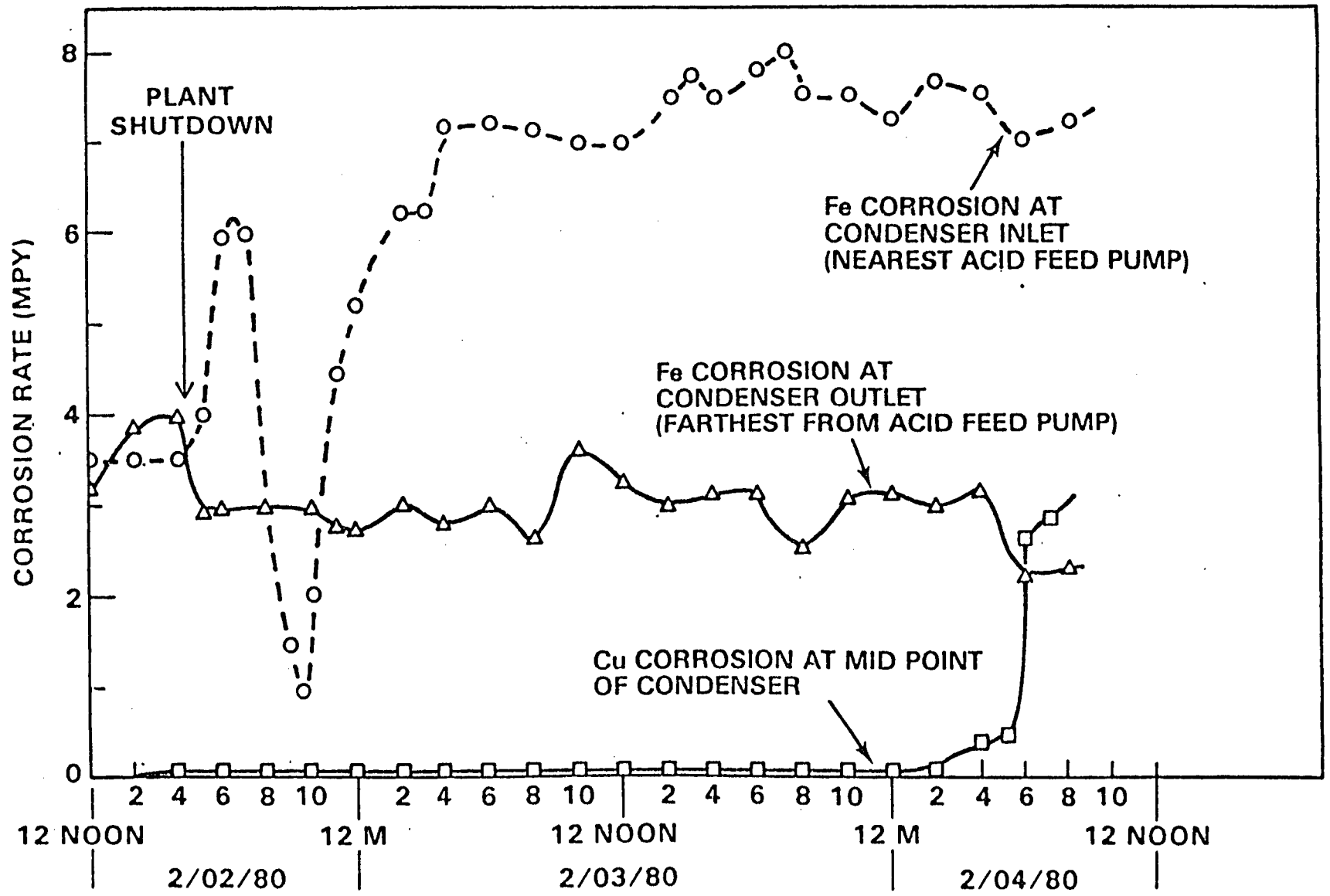

FIGURE 5. Corrosion Probes Detect Sulfuric Acid in Plant Cooling Water System

Costs:	
Instrumentation cost (installed)	$ 5,000
Losses prevented (benefits):	
Retubing heat exchanger	$15,000
Estimated lost income (5 days extra shutdown time; assumes lost income from power charged to customer, 3.06¢/kWh, at a 100% capacity factor)	$37,000
Total Loss Prevented	$52,000

Benefit to Cost Ratio = 52,000/5,000 = 10.4

The benefit-cost of the installed instrumentation is very favorable and shows that the installation is cost effective even if only one shutdown is prevented. Since there is a continued possibility of other unwanted shutdowns, the benefit cost of corrosion probes installed at the appropriate locations is very high.

CASE II - LINEAR POLARIZATION CORROSION PROBE DETECTS HIGH CORROSION IN INJECTION LINE

Although many difficulties were encountered in the development of the Linear Polarization Corrosion Probes, we were able to detect high corrosion rates at the point where the brine leaves the power plant for reinjection into the ground. Because our computer link to the instrumentation we were able to detect the problem at Richland, Washington over 1800 miles away from Magma's Power Plant in California. A call to Magma revealed that a valve had been removed for repair and air was leaking into the brine system, Figure 6, causing an excessive corrosion rate. Since the source of the air was upstream of the expensive injection pumps, it was essential to flush the system with deaerated brine and ensure that no additional air entered the system to prevent possible pump failure.

To estimate the benefit-cost of the Linear Polarization Probe installation the following costs and benefits are projected.

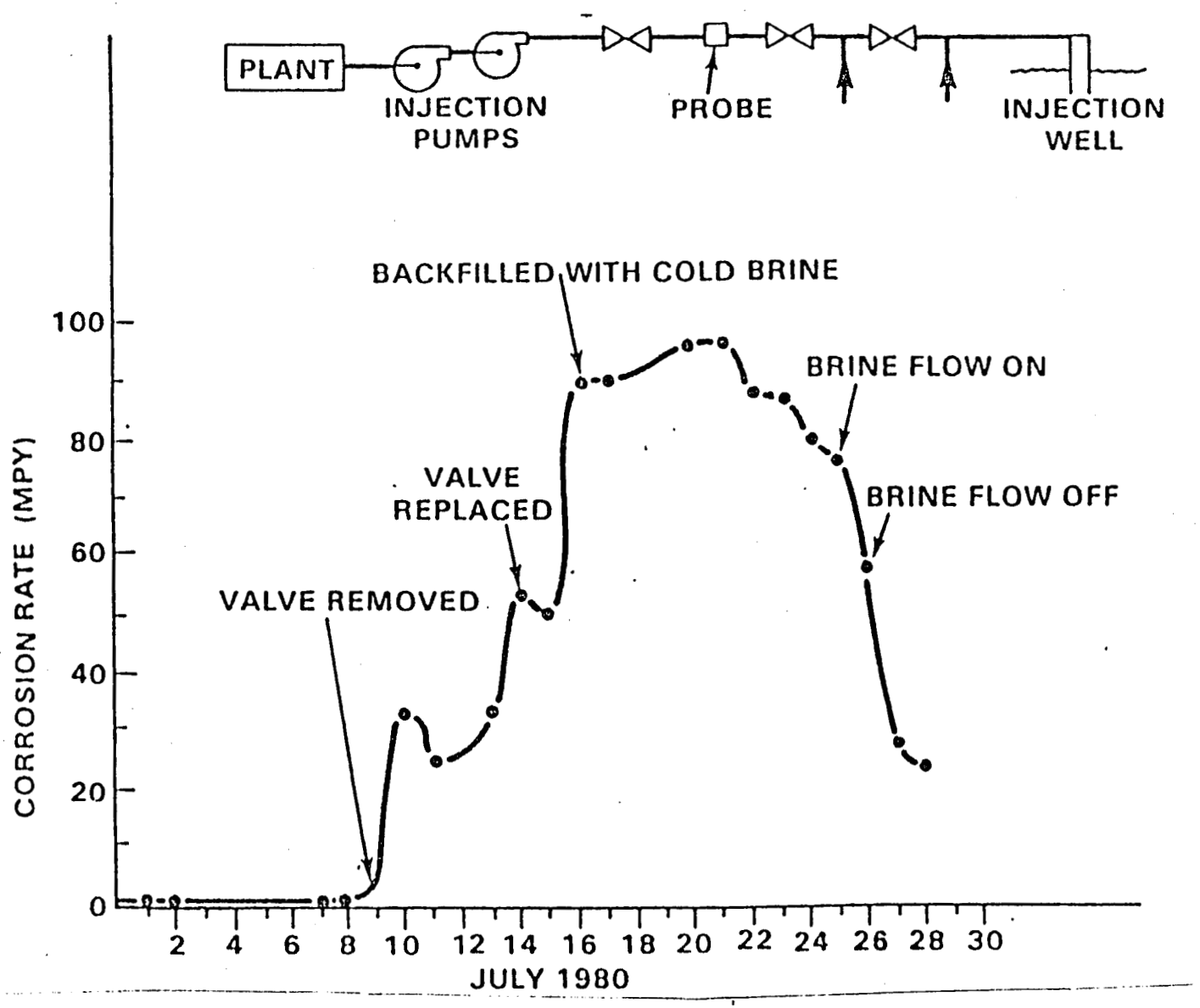

FIGURE 6. Linear Polarization Corrosion Probe Detects High Corrosion in Injection Line

Costs:	
Linear polarization probe (installed)	$ 3,000
Losses prevented (benefits):	
Pump replacement or repair	$25,000
Estimated lost income prevented (5-day shut down, power costs of previous example)	$19,000
	$47,000

Benefit to Cost Ratio = 47,000/3,000 = 15.7

CASE III - CONDUCTIVITY CELL DETECTS MAJOR ISOBUTANE LEAK

A major isobutane leak was detected by the conductivity cell located at the power plant brine outlet, Figure 7. This leak detected during plant start-up was confirmed by analysis of the process conditions from plant control room records. It appears from the conductivity probe data that the instrument detected gas in the exit brine about 30 minutes before the control room detected the loss, requiring shutdown. Proper and immediate interpretation of the information from the conductivity sensor may have prevented a major loss of isobutane.

To estimate the benefit cost of the instrument for preventing the shutdown, the following costs and benefits are projected:

Cost:	
Conductivity probe (installed	$ 6,000
Losses prevented (benefits)	
Replacement of isobutane	$25,000
Total	$25,000

Benefit to Cost Ratio = 25,000/6,000 = 4.1

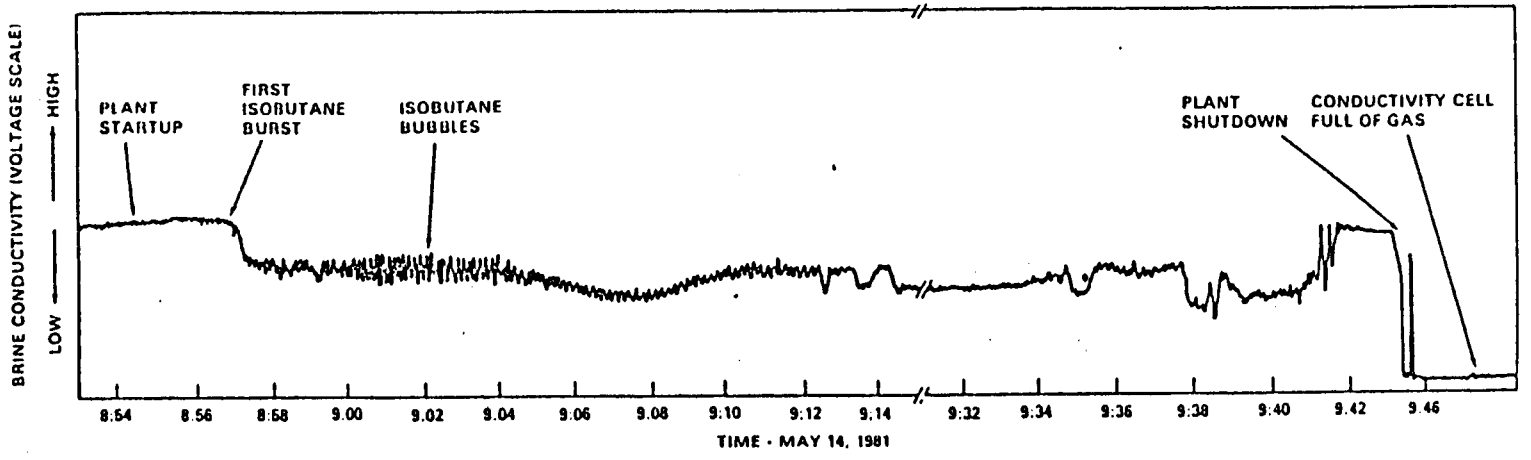

FIGURE 7. Conductivity Cell at Plant Outlet Detects Major Isobutane Leak

Therefore, there is a very real benefit to the installation and proper understanding of data obtained from this instrumentation.

If in the above examples a larger power plant is considered or more unwanted shutdowns are prevented, the benefit-cost ratio of the instrumentation increases rapidly. For example, if the power plant were 100 MWe, the benefit-cost ratio in all these examples exceeds 150. Thus, the revenue loss which would be prevented could have payed for the whole research project at PNL. Similar results are found if the size of the power plant remains the same but multiple shutdowns are prevented. The latter case is hard to deal with analytically but is illustrated by the fact that $124,000 in possible loss could be or was prevented by properly evaluating the real time information provided by the devices identified in the above examples.

CONCLUSIONS

Although in the above examples a simplified benefit-cost analysis was used, a very positive value is shown for installing and using appropriate instrumentation for corrosion control and prevention of unwanted shutdowns. In addition, assuming that many unwanted future shutdowns can be prevented, the projects to develop the instrumentation and/or learn how to interpret the acquired data are well worth their cost.

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