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The geothermal user's viewpoint in this case is somewhat unique. San Diego Gas & Electric Company, by virtue of its activity in geothermal exploration and development since 1972, is in a position to be considered not only a user of geothermal, but a producer as well through the activities of its wholly-owned subsidiary, New Albion Resources Co.

As the Supervisor of Fuel Development of SDG&E and the General Manager of NARCO, I can speak from experience on both sides of the negotiating table. The user's point of view to SDG&E's fuel acquisitions people as they labored to negotiate a contract to buy from a geothermal producer of hot water. As General Manager of NARCO, I am in the position of developing geothermal resources and negotiating contracts to sell some of NARCO's heat to third parties.

So much for the introduction—How does a utility, such as SDG&E, view risk in today's business climate? The answer to that question is very simple. SDG&E has an allowed rate of return of 10.59%. This is based upon 48% debt, having an inbedded interest cost of 8.1%; 14% preferred stock, at a cost of 8.2% and 42% equity. Out rates are supposed to return 14-1/2% on this equity. Let me put these numbers in perspective. In early March SDG&E sold $50 million of mortgage bonds which bear an interest rate of 16%. In mid-March we sold 2-1/2 million shares of common stock for $11.50 per share. The current dividend of $1.52 will yield 13.2% and those dividends are paid after taxes. When money borrowed to build a project costs more than you can earn on the project, there is no incentive to build that project and certainly no incentive to take any risk associated with the project. How does SDG&E view risks? Simple—don't take any risks which can be avoided! Is this attitude likely to change? My forecast is, there is no change in sight.

Does this take SDG&E out of contention as a possible market for producers of geothermal energy? Not likely. For all of its risk aversion, SDG&E still remains one of the best potential markets for any energy producer. A recent article in FORBES MAGAZINE found that SDG&E had the third highest price per kilowatt of any utility in the country—5.9c per kilowatt hour for commercial customers. That was in March, 1980. Energy cost adjustment clause increases resulted in an average commercial price per kilowatt hour of 7.2c in May. In July it is expected to climb to 9.2c. SDG&E's rate territory continues to expand at the rate of 5% annually and it is located just over 100 miles from a major source of geothermal heat in the Imperial Valley. But today, SDG&E has no commercial geothermal heat or power purchase contracts with domestic producers.

You may ask, "Why not?" With no incentive to spend its own money and with a high growth rate, what is SDG&E doing to obtain capacity for its existing and future customers? At the present time, most of SDG&E's capital expenditure for generation is going to the construction of San Onofre Units 2 and 3, a nuclear project which has been under way for ten years and which is expected to start generating commercial power in 1982 and 1983. San Onofre 2 and 3 will add 440 MW of capacity from a reliable, proven generating technology to SDG&E's system. Even with the long delay and large capital costs

5-26
in excess of $1,400 per kilowatt, energy and capacity from San Onofre in 1983 will cost only 5.0¢ per kilowatt hour at a 70% capacity factor. Restrictions on air quality and the use of oil make it very unlikely that SDG&E can build additional fossil fuel capacity in the next ten years. To move to coal gasification or coal liquids also involves risks which the utility is unlikely to be in a position to take until these fuel technologies are demonstrated. Coal-fired plants built in California are also risky from the standpoint of regulatory approval and environmental licensing.

San Diego has embarked on a program to purchase power from proven generating sources within a reasonable distance from its service territory. Where necessary SDG&E will build transmission facilities to make possible the reliable delivery of that power to the load center. The Company is building a major transmission line through the Imperial Valley to Arizona. SDG&E will purchase power under contracts negotiated with utilities in Arizona, in New Mexico and Mexico. In these contracts we are looking at proved direct-fired coal burning technology in Arizona and New Mexico and proved geothermal technology from the operating field at Cerro Prieto in Mexico.

For each of these purchase power contracts, there is a payment for capacity and a charge for energy taken. You may say, "But if you're paying for capacity, you are taking on some of the risk for that source of power." This is true, but the nature of the risk is one which is well known and understood to utilities and is less of a risk than building our own conventional electric generating station.

The prices may sound high by today's standards but are not out of line with the alternatives. The New Mexico purchase in 1983 will cost an average of 5.3¢ per kilowatt hour; the Arizona purchase, an average of 3.9¢ per kilowatt hour (it will increase to 6.5¢ in 1985 when a new coal plant becomes the source) and the geothermal power purchases from Mexico, an average of 7.8¢ per kilowatt hour. These prices in 1983 dollars include both capacity and energy charges. The Arizona and Mexico purchases include a guarantee of 100% capacity factor while the New Mexico purchase is assumed to be at 70%. With today's cost of low sulphur residual oil passing through $30 per barrel or about $5 per million BTU's, SDG&E's current cost of oil to fuel its existing generating stations is 50 mils per kilowatt hour. In 1983 it is projected to be 75 mils per kilowatt hour.

And how about the regulatory environment in California and for San Diego? I can say without hesitation, the California Public Utilities Commission continues to be very supportive of geothermal electric generation. In fact they have ordered SDG&E to aggressively pursue its geothermal plans and to file semi-annual reports with the CPUC, so they may readily follow our progress. The CPUC has granted SDG&E R&D expense treatment for the construction and operation of the proposed Heber binary geothermal plant. They have encouraged SDG&E through the operation of its fuel subsidiary, New Albion Resources Co., to take an active role in geothermal exploration and geothermal development. However, even such significant support as this does not permit the utility to raise significant amounts of capital for projects based on technologies which have not yet been proven successful in this country.

SDG&E is having difficulty raising capital for proven technologies and normal transmission and distribution extensions to serve its growing service territory.

Why couldn't the CPUC simply approve a geothermal plant for SDG&E and assure that the carrying costs and operating costs associated with the project and any amortization necessary in the event of failure could be included in the utility's rates? SDG&E has not suggested this approach. Capital would still have to be raised and the very same thing that makes SDG&E attractive to geothermal developers; that is, a relatively high cost of electricity, makes it equally difficult for the Company and its regulators to continue to increase those rates. It is not really reasonable to expect the customers of one small utility, which is in a good position to use geothermal by virtue of geography, existing oil-fired plants and continuing growth, to bear the burden of verifying that the geothermal plants currently conceived will work and work well.

So what can the developer do to penetrate this best-of-all markets for geothermal with-
out passing the burden of risk on to the utility? What are the contractual options that we can conceive of? The simplest one-party approach would be for the utility to own and operate the reservoir, finance and operate the plant and deliver the power to its service territory. However, this places the maximum risk on the utility, its shareholders and its customers. Another option would be for the utility to purchase geothermal heat from a reservoir developer and finance and build its own plant. This is a system which has worked successfully at the Geysers. However, the element of risk remains for the investment in the plant and transmission, and conceivably for the reservoir if the reservoir operator requires the utility to assure that its energy conversion technology will work satisfactorily.

What option might look good to a utility, such as SDG&E, at this point in time? It is the option we are now following for the bulk of our generating needs. We will purchase power from a plant owned by a third party and pay for capacity, where capacity is proven to exist, and energy as it is delivered.

To produce power for sale to a utility requires the cooperation of the geothermal resource developer, the plant owner and operator, and the utility as well as all the involved regulatory agencies. This is something which can be done and, in fact, is now being proposed. However, the utility does not want to pay for power which the plant cannot generate or to pay higher costs for energy because the plant or reservoir does not operate properly. Since the utility is unwilling to make such guarantees to the plant owner, it is likely the plant owner will be unwilling to make such guarantees to the reservoir owner. Therefore, the contracts connecting utility to plant and plant to reservoir must be skillfully written to provide suitable incentives to insure performance. The result would be three entities who stand to make a profit and serve a need if the total system functions properly.

Each of these entities should bear the risk for the successful operation of its portion of the project. If any of the three has to lean on the others for financial support, it can be expected that the project will topple like a string of dominoes. I have no doubt that most of the mechanisms are in place to allow such a project to be put together. For example: A reservoir could be financed with risk capital which could take advantage of tax benefits associated with drilling and operations. The greatest burden of capital is placed on the plant owner and operator.

It is here that Federal Loan Guarantees implemented at a reasonable pace could carry the risk of technological development. The utility will have to bear the risk of obtaining a transmission path from the site of the geothermal project to its service territory and the risk of no power if either the plant or the reservoir fails. I believe where a significant resource is indicated, utilities will be willing to carry this risk. It is normal to their business.