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GEOTHERMAL DEVELOPMENT IN THE PHILIPPINES

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PREFACE

Since the foundation of the UNU Geothermal Training Programme in Iceland in 1979, it has been customary to invite annually one geothermal expert to come to Iceland as a UNU Visiting Lecturer. The UNU Visiting Lecturers have been in residence in Reykjavik from one to eight weeks. They have given a series of lectures on their speciality and held discussion sessions with the UNU Fellows attending the Training Programme. The lectures of the UNU Visiting Lecturers have also been open to the geothermal community in Iceland, and have always been well attended. It is the good fortune of the UNU Geothermal Training Programme that so many distinguished geothermal specialists with an international reputation have found time to visit us. Following is a list of the UNU Visiting Lecturers during 1979-1993:

1979	Donald E. White	United States
1980	Christopher Armstead	United Kingdom
1981	Derek H. Freeston	New Zealand
1982	Stanley H. Ward	United States
1983	Patrick Browne	New Zealand
1984	Enrico Barbier	Italy
1985	Bernardo S. Tolentino	Philippines
1986	C. Russel James	New Zealand
1987	Robert Harrison	United Kingdom
1988	Robert O. Fournier	United States
1989	Peter Ottlik	Hungary
1990	André Menjoz	France
1991	Wang Ji-yang	P.R. China
1992	Patrick Muffler	United States
1993	Zosimo F. Sarmiento	Philippines

The UNU Visiting Lecturer of 1993, Mr. Zosimo F. Sarmiento is the manager of the Reservoir Engineering and Management Section of the Geothermal Division of the Philippine National Oil Company (PNOC). He was a UNU Fellow in Iceland in 1980, and is the first former trainee to be invited to join the distinguished list of UNU Visiting Lecturers. The Studies Board of the Training Programme decided to invite him on the occasion of the 15th anniversary of the Training Programme.

The Philippines are amongst the leading users of geothermal energy in the world for electricity production. The Geothermal Division of the PNOC is probably the organization with the largest number of staff and the largest amount of activity in geothermal exploration and development in the world at present. It is therefore of great value for the participants of the UNU Geothermal Training Programme to learn from the experience of the Philippines. We are grateful to Sammy Sarmiento for giving us an insight into the various aspects of the exploration and management of the geothermal resources of the Philippines in his five lectures in Reykjavik in August 1993, and for preparing the lecture notes that are presented here.

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TABLE OF CONTENTS

LIST OF FIGURES

Page

Page

LIST OF TABLES

1. UPDATE ON GEOTHERMAL DEVELOPMENT IN THE PHILIPPINES

1.1 Introduction

Two decades ago, the Philippines embarked on a comprehensive energy development programme to reduce the impact of the Middle East oil supply crisis. The government launched this strategic programme to make the country self-reliant in its energy requirements and less vulnerable to foreign supply of oil. In line with this plan, the government expanded its thrust on the exploration and development of indigenous energy resources. It established policies and efforts on the phased departure from the utilization of oil.

From a 92% dependence on imported energy in 1973, the government had reduced it to a more manageable level of 55% in 1985. The country attained this decline on the use of imported energy through diversification of its energy sources: geothermal, coal, hydro, oil and gas, and the other non-conventional energy sources (bagasse, agri-wastes, wind and solar). The government pursued vigorously to develop these resources through executive and legislative actions. It pushed for the updating of antiquated laws to attract foreign investors in oil, gas and geothermal exploration in frontier areas. In 1979, the country's first oil field in Palawan (Nido) began its commercial production at the rate of 40,000 barrels per day. Subsequently, the province of Cebu inaugurated the first large scale power generation using domestic coal with a capacity of 55 MW in 1981.

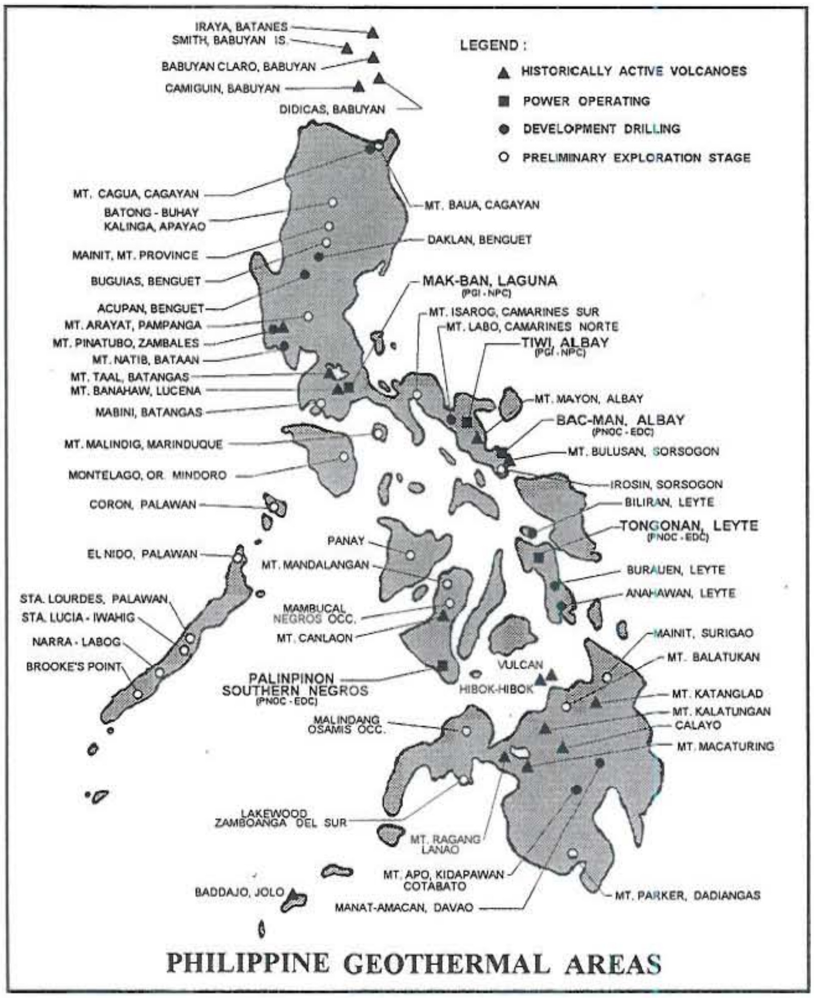
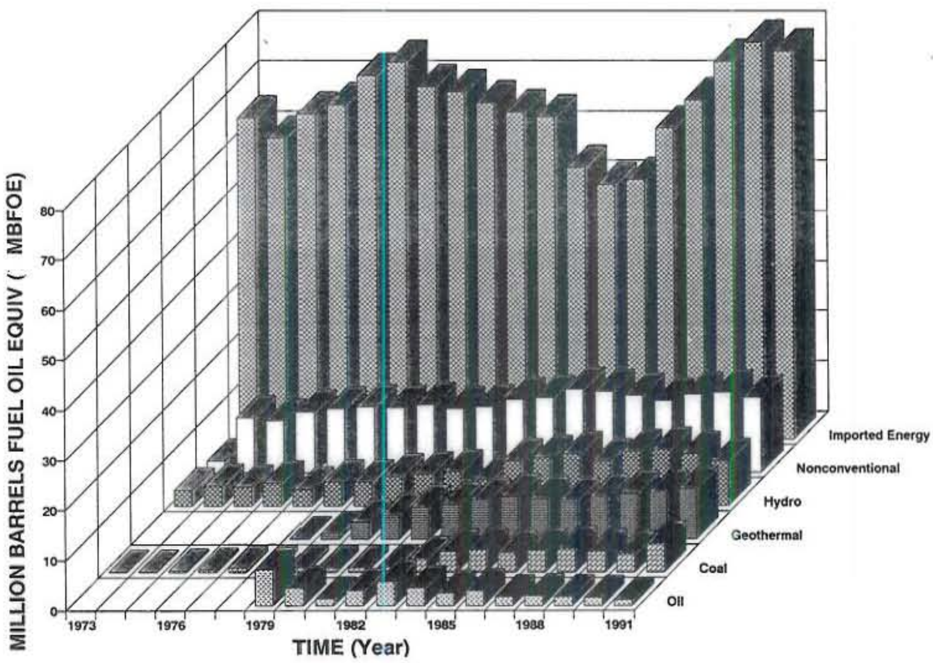


FIGURE 1: Geothermal areas in the Philippines

The Philippines, being situated in the so-called Circum Pacific Belt of Fire, are endowed with vast geothermal resources that can be tapped for energy utilization. Hence, the Commission on Volcanology (now Philippine Institute of Volcanology and Seismology) initiated studies and investigations on the use of geothermal energy, even before the 1973 oil crisis, in 1962. They conducted initial exploration in Tiwi, Albay (Figure 1) and in some other localities with known surface thermal manifestations, e.g., Tongonan in Leyte, Palinpinon in Negros Oriental and Makiling-Banahaw in Luzon near Manila (Tolentino, 1986). The first electric bulb lit by geothermal energy ensued in 1969 in Tiwi, Albay using a 2.5 kW non-condensing pilot plant. The Philippine National Oil Company-Energy Development Corporation (PNOC-EDC) subsequently inaugurated a 3 MW pilot plant in 1977 in Tongonan, Leyte ushering the first commercial exploitation of geothermal energy in the country. In 1979, the National Power Corporation (Napocor) inaugurated the first large scale utilization of geothermal steam for power generation in Tiwi and Makiling-Banahaw (Mak-ban) in collaboration with Philippine Geothermal Inc. (PGI), a wholly owned subsidiary of Union Oil of California. Simultaneous with the development efforts in Tiwi and Mak-ban, PNOC-EDC worked for the commissioning of each of the 112.5 MW plants in Tongonan and Palinpinon in 1983. The continuous build-up of geothermal power generation culminated in the ensuing years with total capacities of 330 MW each for both Tiwi and Mak-ban fields. Consequently, the country achieved a cumulative installed capacity of 894 MW in 1984, after only seven years; catapulting the Philippines to the second largest geothermal producer in the world.

FIGURE 2: Historical statistics of various energy sources in the energy mix of the Philippines



1.2 Geothermal historical performance

Historical data obtained since 1972 illustrate the growth of geothermal sector in the country. Figure 2 shows the energy mix in the country in million barrels of fuel-oil-equivalent (MBFOE). In 1973, the total oil consumption of the country reached 64 million barrels or 92% of the total energy mix. The contribution from geothermal energy had increased from 1.06 MBFOE in 1979. It further increases its contribution to 8.5 MBFOE in 1985. These figures are respectively equivalent to 1 and 9.22% of the total energy mix. However, beginning 1986, the import dependence was again on the rise owing to the recovery of crude oil prices and the onset of economic recovery in the country that generated increases for energy demand. The transport and the power sectors consumed the bulk of this imported energy because they used oil as fuel. Hence, in 1991, imported oil and coal supplied again 65% of the total energy needs of the country.

From a low 3 GWh in 1979, the contribution of geothermal energy had risen to 5,757 GWh in 1991, or 22.4% of the country's power generation (Figure 3). The geothermal share in the power generation mix reached its peak at 26.4% in 1985. The cumulative oil displacement of geothermal from inception to 1991 is about 91.49 MBFOE that is equivalent to \$1.1 billion at a crude price \$12.00/barrel.

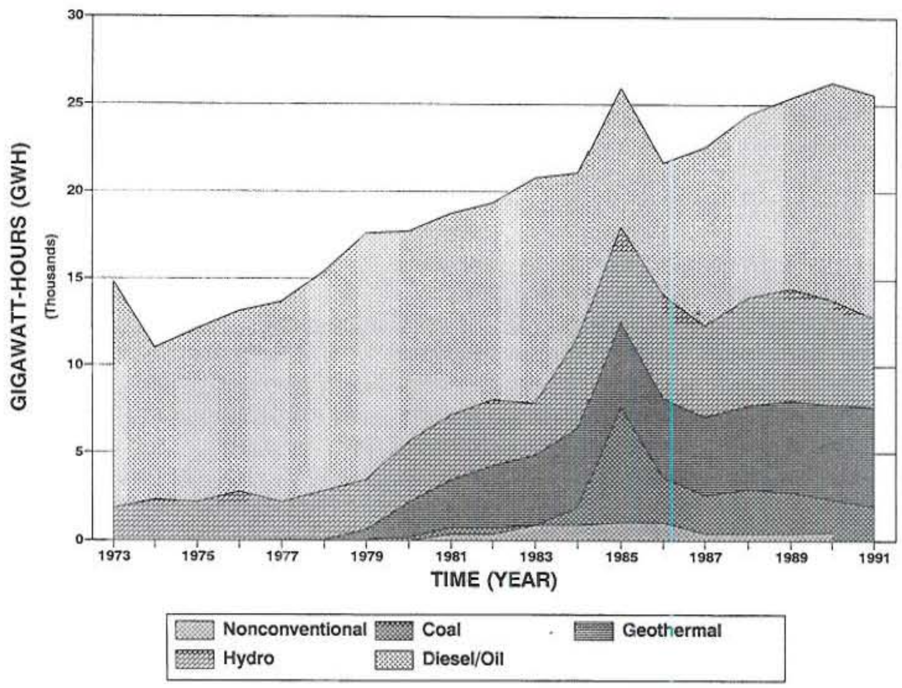


FIGURE 3: Power generation mix of various energy sources in the Philippines

Table 1 shows the installed power generating capacities in the Philippines. From 3,060 MW in 1973, the total installed capacities had risen to 6,789 MW in 1991. Diesel/oil and geothermal account for 49 and 13% of the total installed power generating capacity, respectively. Unfortunately, slowdown in geothermal activities occurred in the second half of the last decade. Companies involved in the exploration of other areas, like Total Exploration of France - in partnership with Philippine Oil and Geothermal Exploration, Inc. (POGEI), and Caltex of USA, stopped their exploration program. They pulled out for various reasons: either for failing to consummate a steam price contract with the government, the high risk involved in the exploration and development of geothermal areas and/or because of the low return on investment imposed by existing laws at the time. While PGI is concentrating on the operation and management of Tiwi and Mak-ban, PNOC-EDC independently pursued the exploration and development of the remaining known geothermal prospects in the country.

To date, at least 27 of these known geothermal prospects have either been investigated in part and/or explored with detailed geoscientific studies and deep drilling; covering an aggregate surface area of 5,300 square kilometres (Figure 1). The outcome of these studies led to identification of five priority areas for development, e.g. Mt. Apo in Mindanao, Mt. Labo, Mt. Cagua and Mt. Natib in Luzon. In the late 80's, PNOC-EDC accelerated the development of Bacon-Manito geothermal project so that it can commission 110 MW for Bacman I and 40 MW for Bacman II in 1993. Corollary to this program, a total of 435 wells drilled since 1972 prove a total cumulative steam flow rate corresponding to of 1,400 MW (OEA, 1992).

1.3 Geothermal power development plan 1992-2000

Following the decision to mothball the 620 MW Bataan nuclear power plant, the country began to experience severe power supply shortages in the latter part of the 80's. The strong demand growths in power recorded as high as 8.4% annually likewise put a strain on the many existing plants that have suffered from operational deficiencies due to maintenance problems and old age. Prolonged drought also limited the availability of hydropower, which has been the country's largest source of energy, losses incurred in the systems distribution and other problems associated with construction of new power plants moderated the gains achieved in the early 80's.

TABLE 1: Installed power plant capacities (MW) in the Philippines (1973-1991)

Year	Hydro	Coal	Geothermal	Diesel/Oil	Non conventional	Total
1973	642	0	0	2418	0	3060
1974	642	0	0	2297	0	2939
1975	642	0	0	2469	0	3111
1976	642	0	0	2399	0	3041
1977	742	0	3	2543	0	3288
1978	748	0	3	2550	0	3301
1979	928	0	223	2923	0	4074
1980	940	0	446	3140	0	4526
1981	940	50	501	3176	0	4667
1982	1262	50	559	3277	0	5148
1983	1585	50	784	3338	0	5757
1984	1666	350	894	3011	0	5921
1985	1961	350	894	2578	0	5783
1986	2147	530	894	2741	1910	6503
1987	2142	535	894	2790	184	6545
1988	2139	525	894	2915	167	6640
1989	2147	525	888	3136	167	6863
1990	2153	525	888	3136	167	6869
1991	2155	405	888	3341	n.a.	6789

The abundance of geothermal energy in the country makes it the most promising among the indigenous sources of energy. The country has an estimated potential of 4,000 MW; with a "proven" 1402 MW and an installed capacity of 888 MW (OEA, 1992). The estimated cost of 43 mills/kWh at an exchange rate of $1.00 = P27.40 (Table 2) makes it the least cost among the various options in the country (Javellana, 1991). However, the long lead time involved in making geothermal plants operational compelled the Napocor to embark on a number of gas turbine projects for their short lead time and quick-start capability. In 1991, a total of 749 MW gas turbines, representing 11% of the total power generation, have been installed. Meanwhile, the government accelerates the development works on several geothermal fields to put on line at least additional 270 MW through 1993-1994, 640 MW through 1996-1997 and 685 MW by the year 2000.

TABLE 2: Comparison of various power plant costs in the Philippines

Development options	Investment cost ($/kWh)	Plant factor	Generation cost ($/kWh)	Lead time (months)
Geothermal	2103	85	.043	36-48
Imported coal	1336	75	.051	45-54
Combined cycle	825	80	.052	36-48
Hydro	3170	59	.077	60-96
Diesel	900	80	.096	18-24
Gas turbine	546	15	.142	18-24

Table 3 and Figure 4 indicate the target installed capacities of the various plant types up to the year 2000. The annual cumulative generation would increase from 5,953 GWh in 1992 to about 17,060 by the year 2000. From the total power generation mix, the estimated increase of geothermal contribution is from 20.74% in 1992, to 25% in 1996 and, finally, 32% at the end of the century (Figure 5). On the other hand, its corresponding percentage shares from the total energy mix are 7.78, 6.16 and 5.81, respectively, in 1992, 1997 and 2000. The target for this decade is 173.3 MBFOE (Figure 6) which translates to a foreign saving's outlay of $2.08 billion.

TABLE 3: Target installed power plant capacities (MW) in the Philippines

	1992	1993	1994	1995	1996	1997	1998	1999	2000
Hydro	2236	2241	2241	2241	2241	2241	2241	2241	2509
Coal	405	405	1005	1655	1955	2305	2305	2605	3205
Geothermal	888	1123	1143	1323	1483	1923	2263	2483	2483
Diesel/Oil	3457	3463	3643	3643	3643	3469	3469	3469	3469
Combined cycle	520	520	520	520	520	520	520	520	520
Total	**6986**	**7746**	**8372**	**9202**	**9662**	**10452**	**10798**	**11318**	**12186**

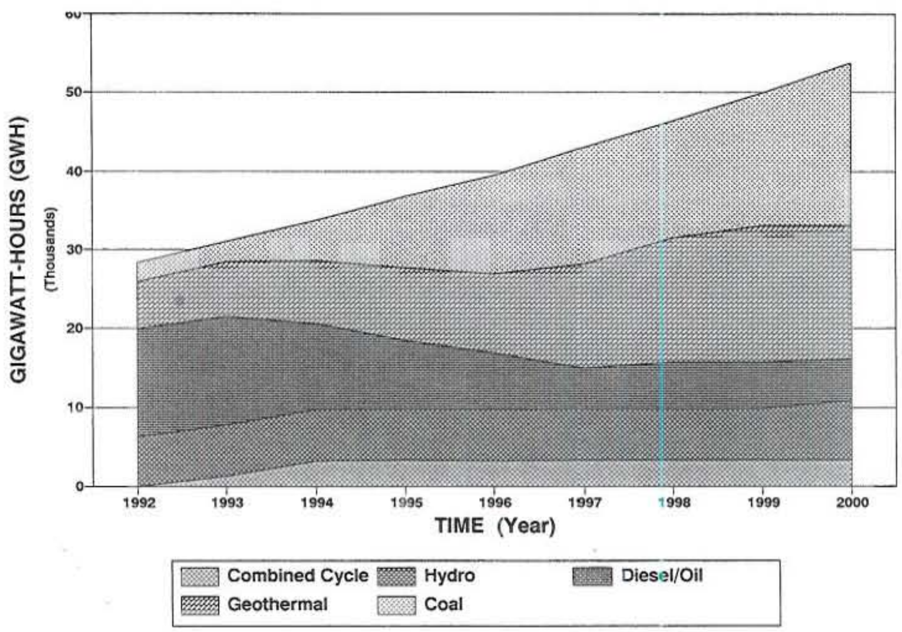


FIGURE 4: Target power generation mix of various sources of energy (1992-2000)

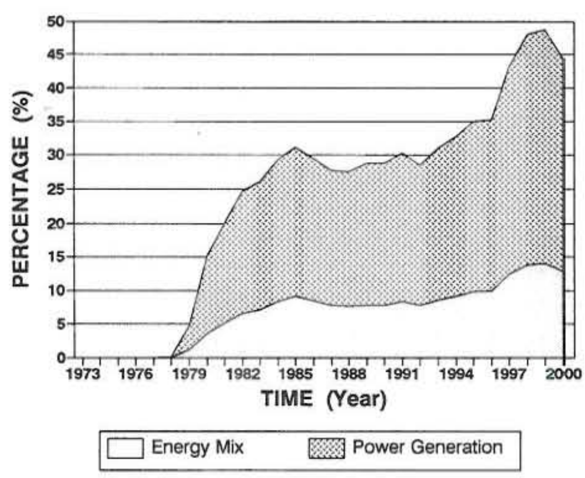


FIGURE 5: Percentage share of geothermal energy in the country's energy and power generation mix

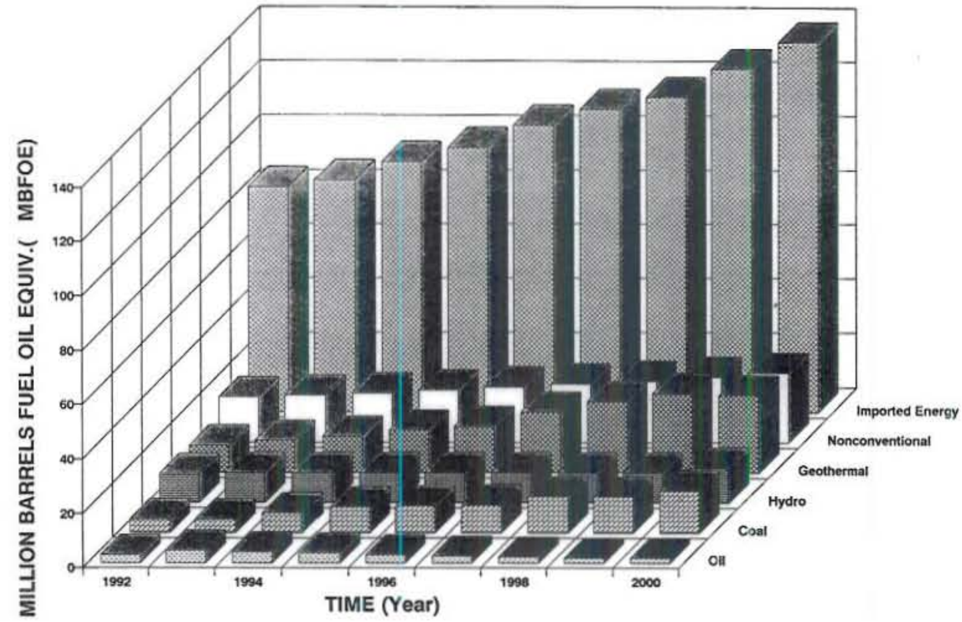


FIGURE 6: Target energy mix of various sources of energy in MBFOE (1992-2000)

1.4 PNOC-EDC steam field development plan

The blueprint of PNOC-EDC's development programme hinges on the power demand forecast of the National Power Corporation. In Luzon, severe power outages compelled the government to fast-track several geothermal related projects that include the interconnection of Leyte to this island through submarine cable. In the Visayas, linkage of Cebu and Negros Oriental is already underway, and this will be followed by Leyte-Cebu interconnection in 1995 (Figure 7). The dwindling power supply from hydro resources in Mindanao also underscores the acceleration of geothermal exploration and development activities in the area. In line with this program, PNOC-EDC intensifies its efforts in the projects in Table 4.

The successful completion of all these projects would enable PNOC-EDC to generate a total of 1,169 MW_e on top of the existing 228 MW from Tongonan I and Palinpinon I.

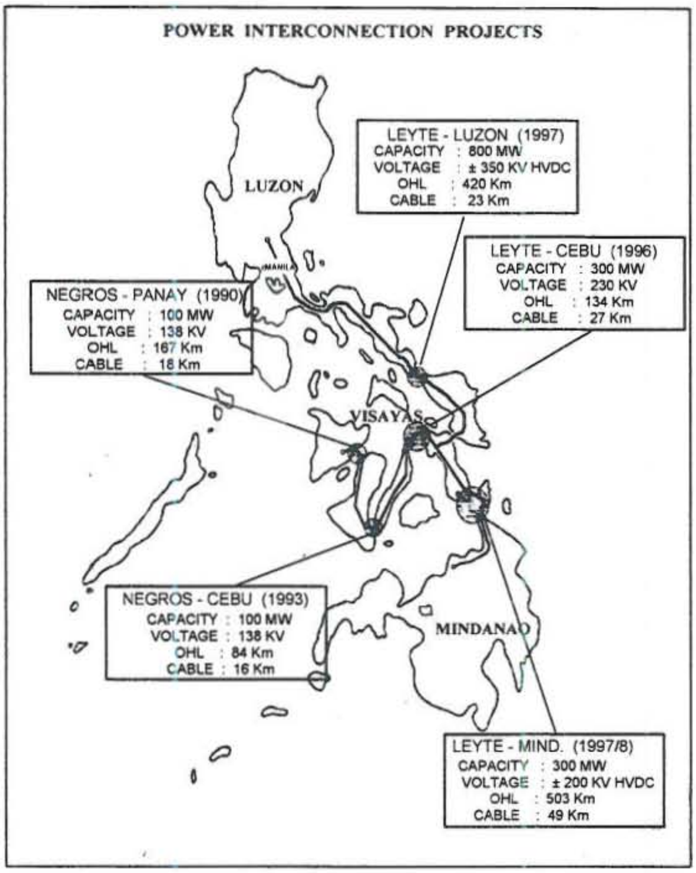


FIGURE 7: Islands to be interconnected through submarine cables

TABLE 4: Target geothermal power plant commissioning dates

Area	Capacity (MW_e)	Commissioning date
LUZON		
Bacman I	**110**	Aug. 1993
Bacman II	**40**	Dec. 1993/March 1994
Bacman binary power	**16**	Under negotiation
Bacman bi-phase	**3**	Under negotiation
Mt. Labo	**120**	1995
VISAYAS		
Palinpinon II	**80**	October 1993
N-Negros	**40**	1995
Leyte A	**640**	
Leyte-Cebu	200	
Upper Mahiao	130	July 1996
Malitbog	70	July 1996
Leyte-Luzon	440	
Malitbog	170	July 1997
Mahanagdong	165	July 1997
Alto Peak	80	July 1997
MINDANAO		
Mt. Apo	**40**	September 1994
	80	1995
Total	**1169**	

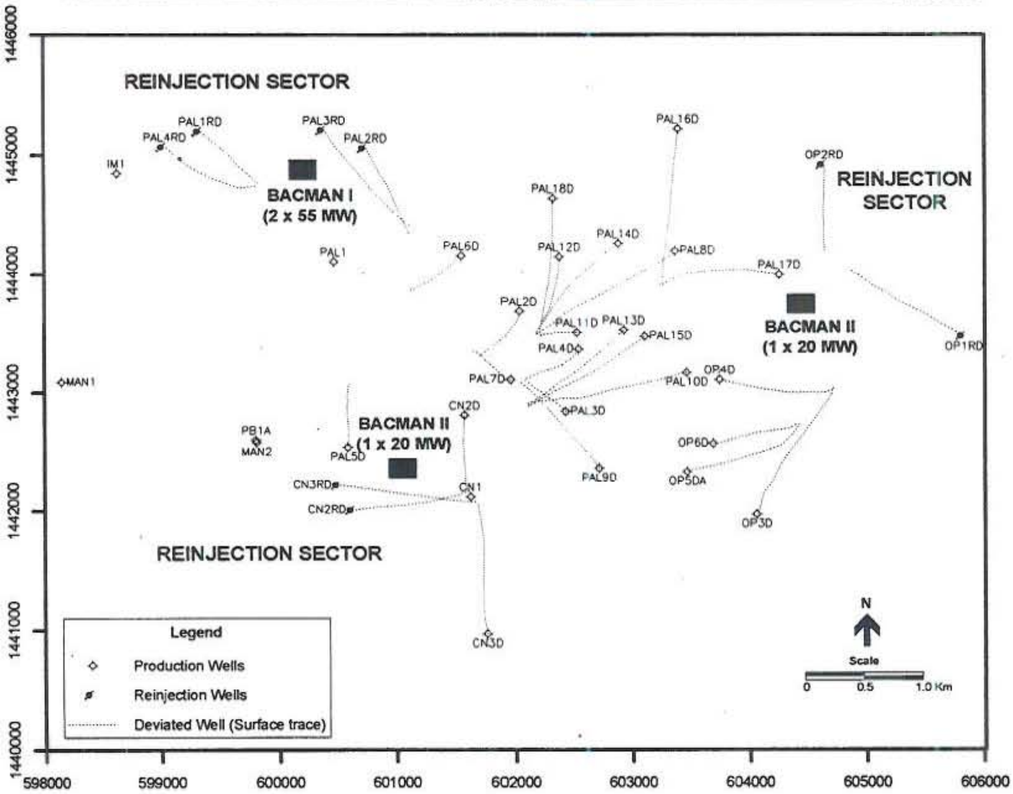


FIGURE 8: The location of wells at the Bacman geothermal field

Bacon-Manito geothermal project
Located southeast of Manila in the boundary of Sorsogon and Albay provinces (Figure 1), this project has an estimated capacity of 150 MW for 25 years. Its commercial operation started in August 1993 with the commissioning of the first 55 MW unit of Bacman I. PNOC-EDC will commission the second 55 MW unit in September, followed by the first 20 MW unit of Bacman II in December and, subsequently, by the second 20 MW unit in March 1994. To date, a total of 37 wells have been drilled, targeted along the Palayang Bayan for Bacman I and Cawayan and Osiao-Pangas for Bacman II (Figure 8).

Binary plant
A framework for the installation of a 16 MW Ormat binary power plant downstream of the Bacman I reinjection system is being laid out to make use of the waste heat from Bacman I. This waste heat can generate electricity by using the spent brine from Bacman I to heat up the secondary fluids that have low boiling point and high vapour pressure at lower temperatures than steam. Heat transfer takes place from geothermal brine to the secondary fluids through heat exchangers allowing the vaporization and expansion of the secondary or working fluid at some lower temperature and pressure.

In this particular scheme (Figure 9), the binary plant will use 350 kg/s out of the 531 kg/s total brine from Bacman I. The brine interface temperature shall be 185°C while the discharge temperature shall be 121°C. There will be acid injection into the line to modify the pH and delay the polymerization of silica during the process in the heat exchanger to avoid and/or minimize silica scaling. The brine shall be cooled further in the settling pond after passing the heat exchanger to precipitate the silica before it is reinjected into a dedicated cold injection well.

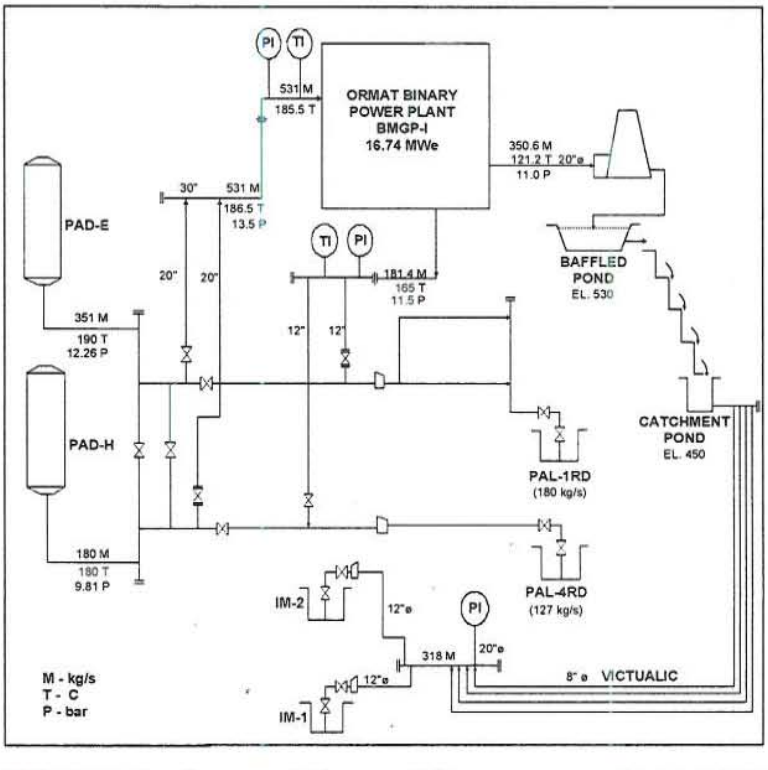


FIGURE 9: Proposed Bacman I binary power plant scheme

Bi-phase turbine or rotary separator turbo alternators
As part of the company's commitment to widen and optimize geothermal power, a 3 MW bi-phase turbine is being negotiated for pilot operation at well Pal-14D in Bacman I. This turbine will utilize the two-phase, steam-water mixture of the well to run the turbine which is to be installed as a topping cycle plant of Bacman I. Douglas Energy (1991) showed that the bi-phase turbine can generate a 19% increase in power with the installation of this system as a topping unit in the main flash plant. Figure 10 illustrates a scheme of this bi-phase retrofit application.

Mt. Labo geothermal project
The Mt. Labo geothermal project is located in the province of Camarines Norte at the northern tip of the Bicol peninsula in southeastern Luzon (Figure 1). This area was first explored by Total Exploration (TOTAL) and POGEI covering about 120,000 hectares. PNOC-EDC explored the

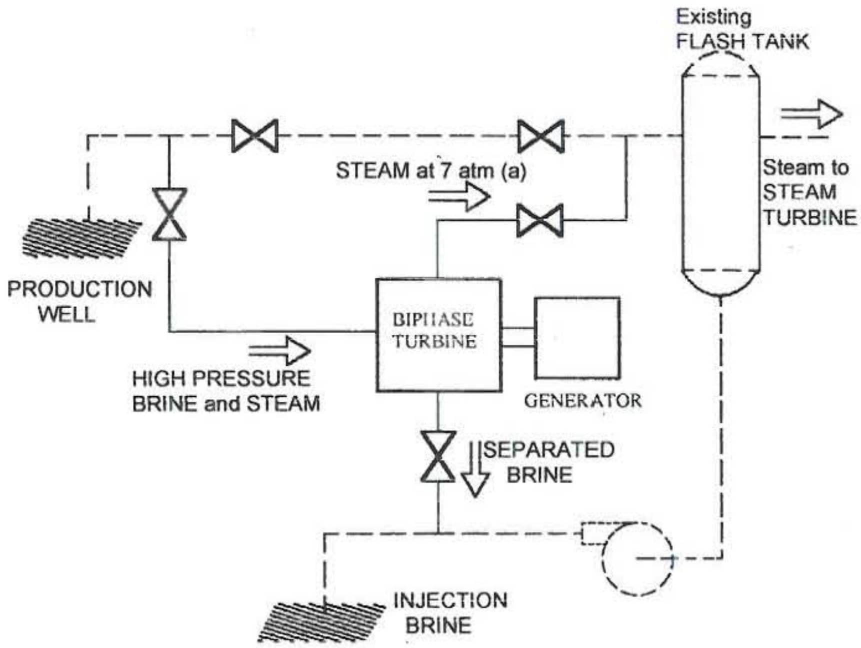


FIGURE 10: Proposed scheme for bi-phase power plant in Bacman well PAL-14D

area in 1987 when the above companies pulled out of the project. Results of geophysical and geological surveys, as well as the existence of neutral chloride springs, delineated a large, active geothermal resource within a 600 km^2 area. The first exploratory well (LB-1D) drilled in 1990 towards the postulated upwelling zone exhibited maximum temperature of 269°C at -1700 m a.m.s.l. Insurmountable drilling problems led to the abandonment of the second well after reaching 1618 m. In 1992, the third well (LB-3D) was drilled to probe the area southwest of LB-1D and

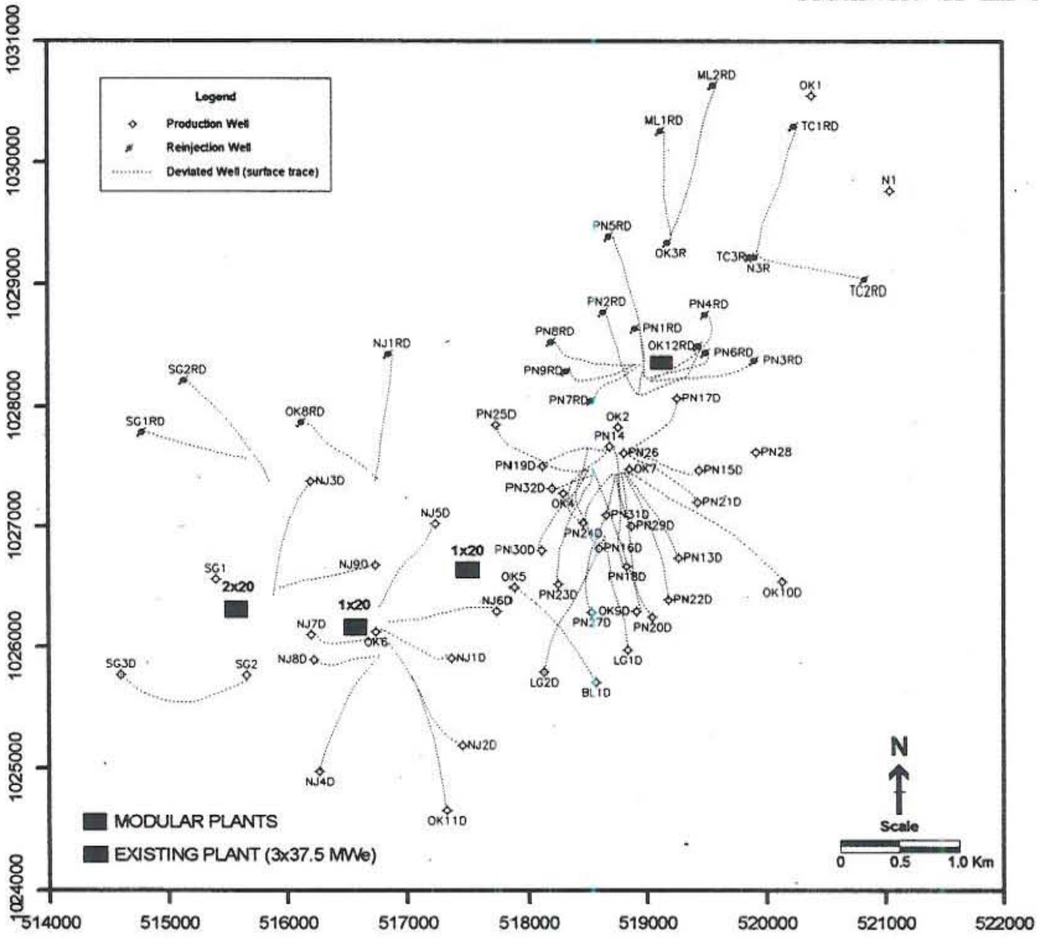


FIGURE 11: Well location map of Palinpinon geothermal field

confirm the existence of neutral fluids at that region. The output of wells LB-1D and LB-3D are 4 and 6 MW, respectively. The fluid chemistry, however, suggests that a long term discharge of these wells is not feasible. The wells intersected the Mabahong Labo fault that appears to be a conduit of SO_4 rich fluids formed by the oxidation of H_2S at shallower levels. However, despite the low pH of the discharge fluids in these wells, the results of the output tests and the neutral chloride discharge from other feed zones in the wells confirm the existence of a geothermal resource in the area. The second stage 3 well drilling programme shall begin in March 1994 to further delineate the area and prove the permeability of other identified structures in the anomaly. This programme shall culminate with the commissioning of a 120 MW plant in 1995.

Palinpinon geothermal project
The Palinpinon geothermal field lies in the province of Negros Oriental within the western Visayas region (Figure 1). The field has an installed capacity of 112.5 MW and is now in the final stages in the construction and commissioning of additional 80 MW by the end of this year. The 3x37.5 MW Palinpinon I plant is presently being supplied by 25 wells in Puhagan while Nasuji, Sogongon and the Balas-balas areas shall produce steam for the additional 4x20 MW Palinpinon II (modular type) plant (Figure 11). Since 1983, Palinpinon I have been energizing the island of Negros. When the submarine interconnection between Negros and Panay was completed in the latter part of 1989, Palinpinon I started supplying bulk of the two islands' power requirements. The additional reserve of 80 MW delineated in Palinpinon II, spurred the government to launch in the second quarter of 1993 the linkage of Cebu and Negros through submarine cable. This grid interconnection will assure Cebu of a more reliable power supply from Palinpinon II that can displace a portion of the 96 MW power barges currently used in augmenting the existing 105 MW coal fired power plants.

Northern Negros geothermal project
The Northern Negros geothermal project is situated in the province of Negros Occidental, approximately 100 km northwest of Palinpinon geothermal field (Figure 1). The project comprises three separate areas whose boundaries are roughly coincident with the volcanic edifices of Mts. Silay, Mandalagan and Canlaon (Figure 12). The results of surface exploration in the three areas, as well as the downhole data from two shallow wells drilled in Mambucal; at the northern flank of Mt. Canlaon, indicate possible existence of a geothermal system in this prospect. Predicted temperatures were in the range of 227-263°C. These findings led PNOC-EDC to embark on a 3 well drilling programme starting January 1994. The program envisions to add power export to Cebu once PNOC-EDC commissions a 40 MW plant in 1995 in this area.

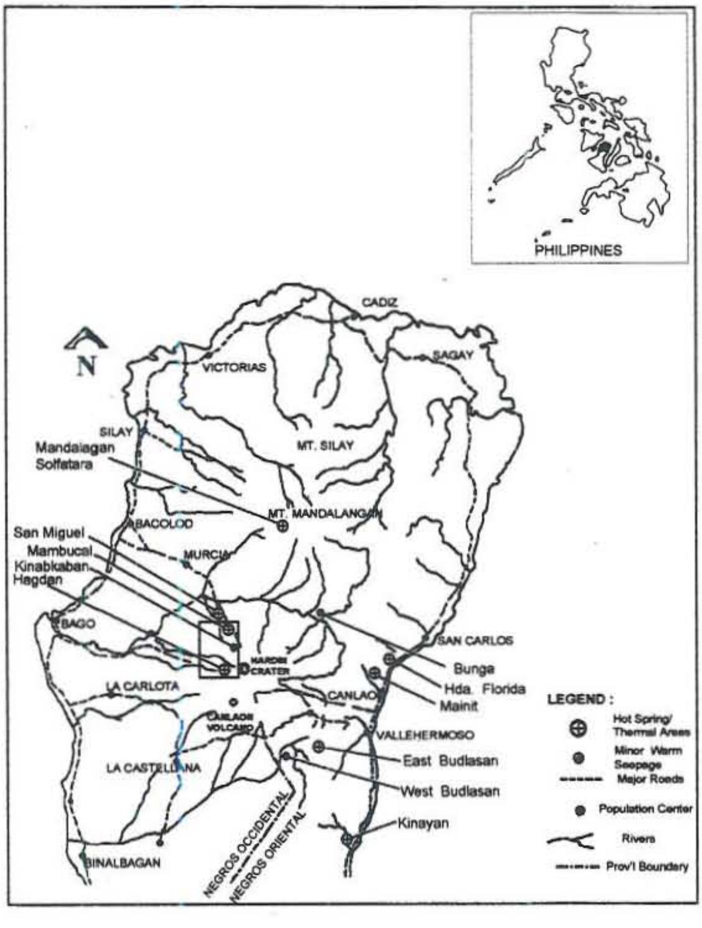


FIGURE 12: Location map of Northern Negros geothermal project

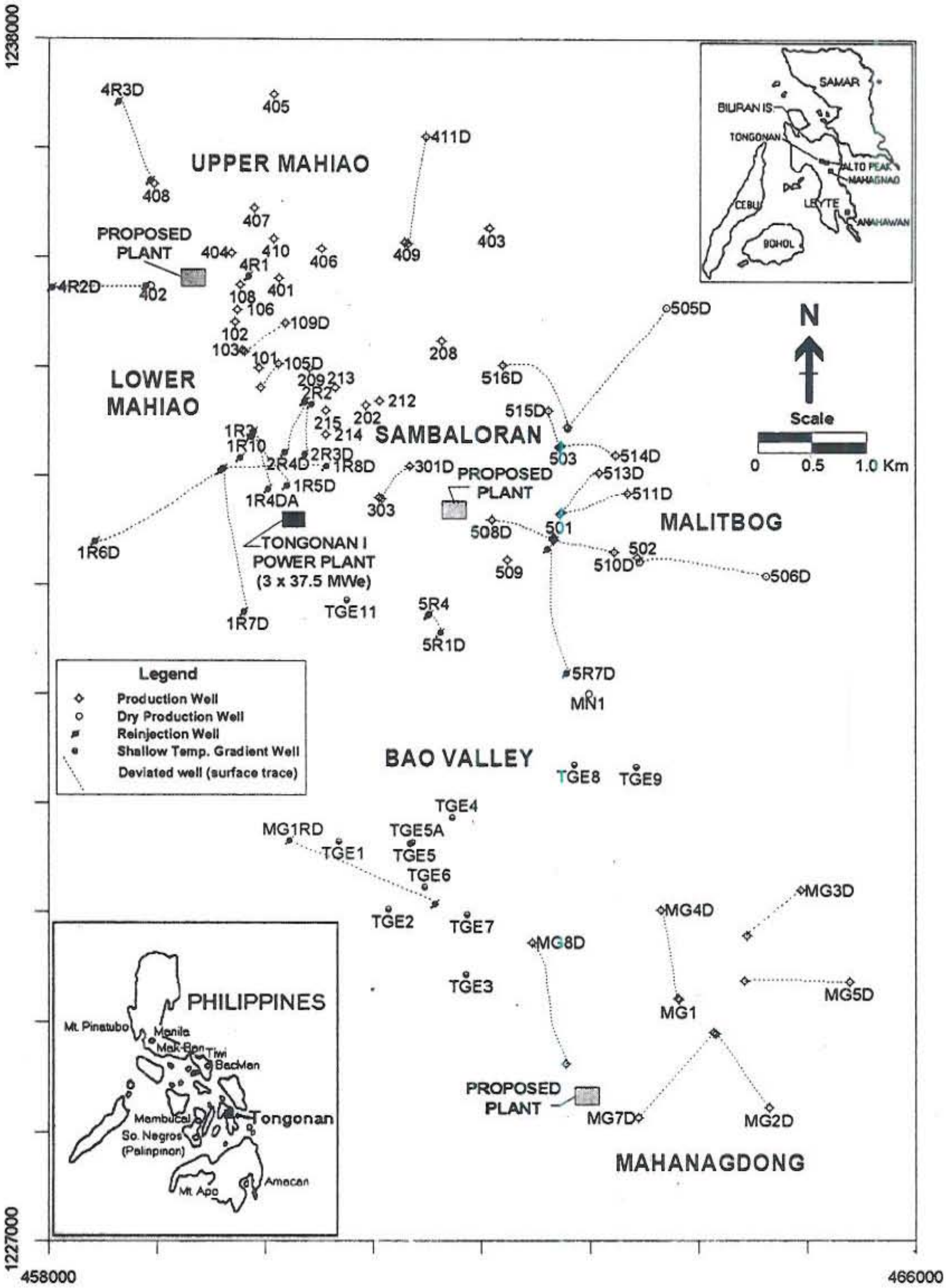


FIGURE 13: Well location map of the greater Tongonan geothermal field

Leyte A geothermal project
As part of the country's long term programme to use indigenous energy resources, the government has decided to link Leyte-Luzon and Leyte-Cebu through submarine cable. The Leyte A geothermal project comprises those areas in Leyte (Figure 13) that can provide power for the first 640 MW. Another project, that is called Leyte B comprises those areas that can supply power besides Leyte A. The first 200 MW are to be supplied to Cebu while the next 440 MW will be supplied to Luzon starting in 1996 and 1997 respectively. The approval to go on with

this project came after the feasibility and economic studies indicate that it is more competitive than other cheap alternative sources like coal despite the additional cost to be incurred in the submarine cable. This project will be built as the biggest single geothermal project in the Philippines.

Recent assessment of the Leyte A project indicates that it can supply the 640 MW. These estimates were borne out by the results of the optimization studies conducted by Sarmiento et al. (1992); Mesquite (1992) and Sarmiento et al. (1993). These studies indicate that Upper Mahiao and Malitbog sectors can be developed at pressures higher than those pressures usually set in the geothermal turbines in the Philippines, i.e., 0.5 to 0.7 MPaa. The resource and process optimization and/or maximization of power generation indicates that the needed 640 MW can be available in the Greater Tongonan geothermal field if the turbine pressures were in the range of 1.0 to 1.2 MPaa. This strategy takes advantage of the benefits of increasing the thermodynamic and generation efficiencies that reduce specific steam consumption, i.e. kg/s of steam required per MW generated from high pressure turbines. This low specific steam consumption enables the optimization and maximization of the projected capacity estimates of Upper Mahiao, Malitbog and similarly Mahanagdong. Sarmiento et al., 1992 predicts from the simulation that the field can sustain higher pressures throughout the 25 year life, provided appropriate reservoir management strategies are adopted. These findings serve as the basis of PNOC-EDC to install the first high pressure geothermal turbines in the country.

Mindanao I geothermal project
The Mindanao I geothermal project is located in the provinces of North Cotabato and Davao del Sur in south-central Mindanao. The main geothermal field is situated within the environs of the Mt. Apo national park. Initial exploration in the area started in 1983-1984. The results of these studies indicate the existence of a large geothermal resource associated with the Mt. Apo heat source. The range of temperatures (240-258°C) measured in the first two wells that were drilled in 1987-1988 confirmed the above findings. Initial resource assessment studies indicate the potential of the area to be more than 250 MW, with a probable maximum capacity of 500 MW (PNOC-EDC,1989). To date, 5 MW have been proven from the 2 wells so far tested in the area (Figure 14).

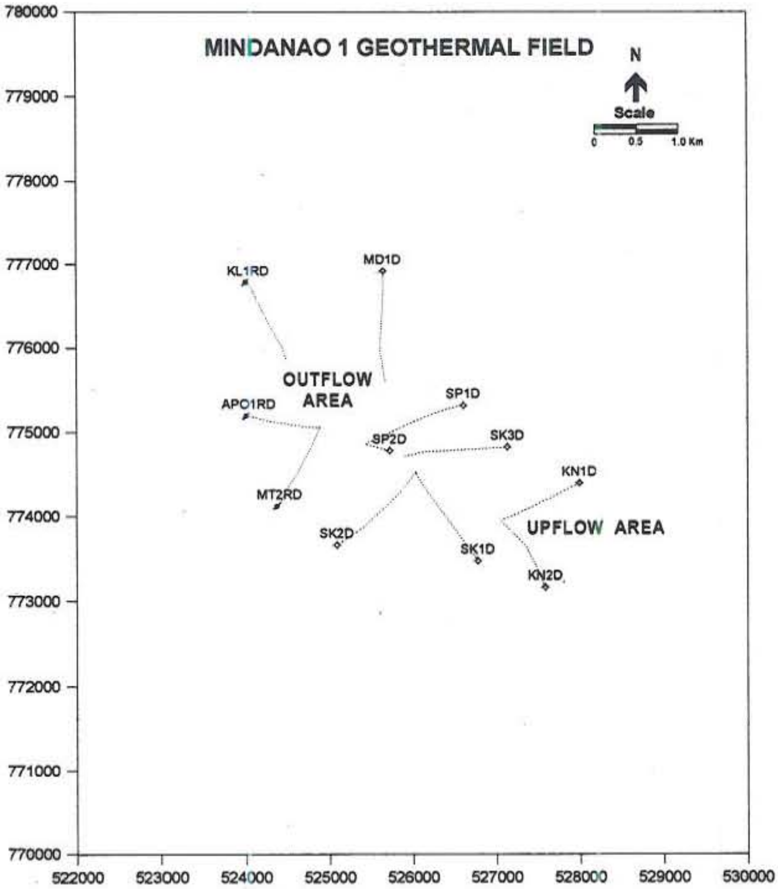


FIGURE 14: Well location map of Mt. Apo geothermal field

Rising environmental anxieties on the development of the area stopped the additional drilling programs in 1988. Opposition from various groups, usually non-governmental organizations, uses several issues against the project, i.e. pollution, deforestation, desecration of tribal minorities' religious beliefs, etc. However, the issuance of Presidential Executive Order 223 in 1992 authorized PNOC-EDC to develop approximately 700 hectares of the park for geothermal power generation. Resumption of the work took place in 1992 upon the issuance of the Environmental Clearance Certificate (ECC) by the Department of Environmental and Natural Resources. The fast-track programme of this project calls for the utilization of 3 rigs to attain the commissioning schedule of the first 40 MW in the third quarter of 1994.

Mt. Natib geothermal prospect
Geothermal prospecting of the Mt. Natib resource in Bataan, Central Luzon began in 1987. Results of the geological, geophysical and geochemical surveys of the area indicate the existence of a potentially viable hot resource. By 1989, two wells were drilled in the western and northwestern flanks of the crater of the extinct volcano, and within the Natib Caldera structure. However, both wells were analyzed to have poor permeability. Moreover, downhole surveys in both wells showed measured temperatures to be quite low with its downhole profile indicating near-conductive temperature gradients. Discharge attempts were undertaken on the second well, NA-2D, to test if the well will sustain flow. The well was stimulated using the portable Clayton boiler. The attempt was unsuccessful as the boiler broke down before the stimulation could be completed. Further exploration of the project was halted afterwards. Although with the recent encouraging results of gas lift stimulation of wells in Mt. Labo (Camarines Norte) which showed similar characteristics as those in Mt. Natib, re-discharging of the wells is being re-evaluated and may lead to the possible reopening of the project.

Mt. Pinatubo geothermal prospect
Prior to detailed exploration efforts conducted by PNOC-EDC in the early 1980's, very little geothermal investigation work has been undertaken in the area, except for some brief reconnaissance surveys. The most recent geoscientific studies in the area were conducted by PNOC-EDC from 1982 to 1984. Three deep exploration wells were drilled subsequently in 1988-1989. Of the 3 wells, only PIN-2D produced at a commercial rate, i.e. 7.7 MW_e at 0.55 MPa wellhead pressure. Furthermore, despite high temperatures measured downhole (over 300°C), all 3 wells were acidic and could not be used for exploitation. The project was subsequently shut in 1990, a year prior to the eruption of Mt. Pinatubo.

Mt. Cagua geothermal prospect
The prospect is in the northeasternmost tip of Luzon island and covers about 504 km^2. Surface geoscientific studies were conducted in 1988 to 1989. The resource was estimated to support at least 25 MW_e. Two exploration wells were drilled in 1990. CG-1D, drilled into the Mt. Cagua collapse structure representing the surface expression of the volcanic vent, encountered temperatures over 300°C. However, CG-2D which was drilled outside the structure about 1.4 km northwest of CG-1D, encountered low temperatures (about 180°C). CG-1D produced at subcommercial rates, whereas CG-2D was not discharged due to its low temperatures. Further development of the resource is deferred and the project was closed in 1991.

Mahagnao geothermal prospect
The Mahagnao geothermal area, covering about 150 km^2 is located in Burauen, Leyte in Central Philippines. Geoscientific investigations of Mahagnao were initiated by the then Philippine Commission on Volcanology in the early 1970's in conjunction with surface exploration in Tongonan. From 1980 to 1982, the Burauen geothermal prospect, which includes Mahagnao and Mt. Lobi, was investigated by PNOC-EDC and includes geologic mapping, resistivity surveys and

mapping of thermal manifestations plus geochemical and isotope analysis of thermal springs. Two exploration wells were drilled in the area between October 1990 and April 1991, intersecting reservoir temperatures between 240 and 280°C. Only the first well, MH-1D was tested. The reservoir is believed to be liquid dominated, although MH-1D discharged superheated steam due to large pressure drawdown. Both PNOC-EDC geoscientific staff and the Mesquite (1992) recommended further exploration of the area.

1.5 Non-electrical application

Although the Philippines ranked second in tapping geothermal energy for power generation, direct application geothermal energy for non-electrical application remains underdeveloped. In 1974, a full-scale test facility for manufacturing salt from sea water using geothermal energy from the same well supplying the 2.5 kW power generating unit was installed by COMVOL, the National Science and Development Board and the Philippine Navy in Tiwi geothermal field. It continued to produce good quality salt until 1979 when the commercial power generation began. Since then, the focus of geothermal development has been on power generation.

In 1983, PNOC-EDC delineated the outflow area of the Bacman geothermal field and found it to be suitable for non-electrical application because of the relatively low enthalpy characteristics of the wells. This finding formed the basis of applying for a grant from the UNDP to evaluate the feasibility of using geothermal energy in an agro-industrial project to be established in the area. The project entitled "The Development of Geothermal Energy for Power and Non-Power Applications" (PHI/85/003) later recommended the setting up of a geothermal agro-industrial demonstration plant to present itself the validity of using geothermal fluid for crop and fish drying. However, the results of the study indicate that a demonstration plant would not be economically viable in the area because of lack of good market. Studies conducted in other areas revealed that Palinpinon in Southern Negros would be the most promising site for the agro-industrial plant.

In 1992, UNDP approved the project PHI/88/015 "Geothermal Agro-Industrial Demonstration Plant" as a continuation of Project PHI/85/003. This project is now being managed by the Energy Research Development Centre of PNOC-EDC. The main objective of the project is to enable the Philippines to be self-sufficient in the development and operation of geothermal resources for direct use in agro-industrial applications. The project specifically aims for the installation and operation of a 1.5 MW_{th} pilot crop drying facility using low-enthalpy waste geothermal heat from Palinpinon I brine.

Figure 15 shows the schematic diagram of the drying facility. The facility has a designed capacity of handling 14 MT/day of coconut meat equivalent to about 8 MT of copra as finished product. The plant can also handle other agricultural and marine products: mango, cassava, jackfruit, papaya, pineapple, seaweed and fish. PNOC-EDC agreed with the various suppliers to sustain the supply of the local products to keep the plant under operation. The scheduled completion of this project should pave the way for the attainment of another PNOC milestone in pioneering the commercial use of geothermal energy for non-electrical application.

1.6 PGI steam field development plan

The PGI is the only company engaged in geothermal development in the country other than PNOC-EDC. It operates and manages the Tiwi and Mak-ban geothermal fields with 330 MW each of installed capacities. In Mak-ban, a total of 63 production and reinjection wells support

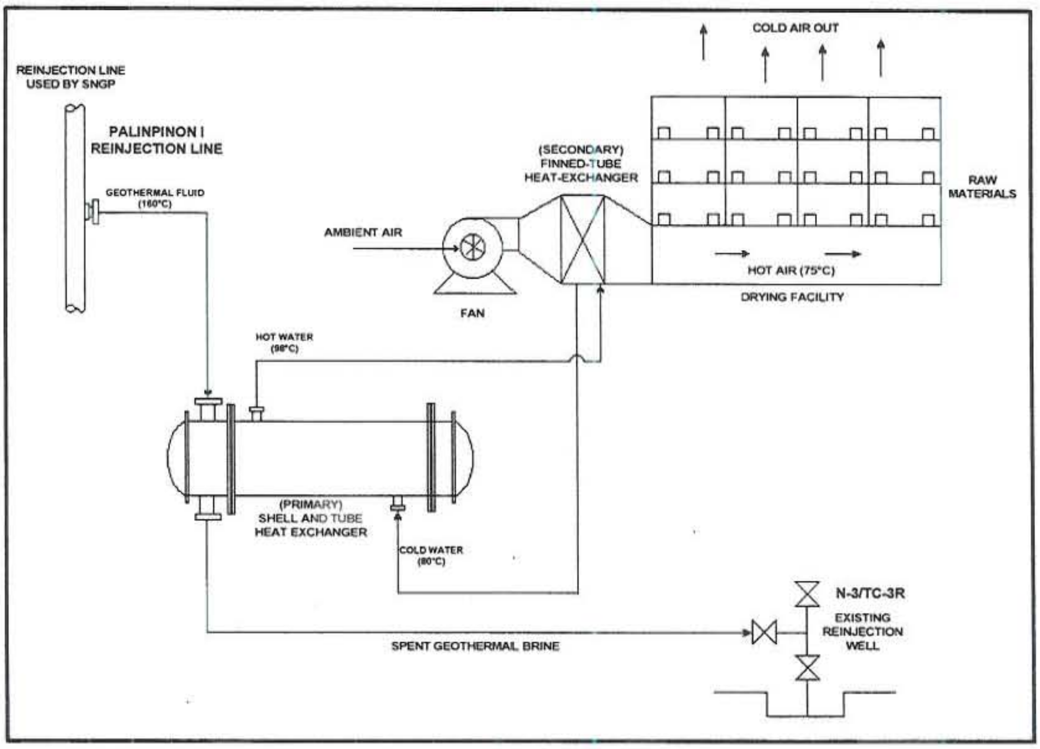


FIGURE 15: Schematic diagram of the drying plant facility in Palinpinon geothermal field

the whole fluid collection and disposal system. On the other hand, Tiwi produces steam from 52 production wells with 11 reinjection wells. In December 1993, PGI will commission the first binary power plant (ORMAT) in the country utilizing waste heat from the Mak-ban geothermal brine. It will have a total capacity of 15 MW. In 1994, PGI will install 4x20 MW modular units in Mak-ban besides the existing 330 MW capacity. PGI will further increase their installed capacity with the commissioning of a 10 MW power plant at Maibarara field, approximately 7 km from the Mak-ban field. Hence, in 1994, PGI would have a total of 765 MW installed capacity.

1.7 Geothermal manpower development

With the company's expansion program, the existing organization of PNOC-EDC Geothermal Division will grow from a previous 1,075 manning complement to 1,368 positions in 1993 and finally to 1,913 to meet the 1996 objectives (Javellana, 1991). The immense training requirements of the company's personnel who will man the slots compared well to the needs that existed in the early 80's when the company was gearing for the development of Tongonan and Palinpinon. Table 5 depicts the inventory of foreign training courses availed by some PNOC-EDC personnel. The list indicates the high level of expertise that the company has maintained since it launched its technology transfer programme in 1976. Over 30 consultants from New Zealand in the Philippines in the late 70's, were reduced to 2 in 1986 and are at present 5. The remaining consultants are being maintained to render second opinions on important issues affecting project management and operations, notwithstanding the requirements of financing institutions.

Consistent with its personnel development programme and to cope with the training exigencies, the company keeps up its on-the-job training program with local and foreign experts. It continues to support foreign training in diploma, specialized and short courses; short training missions; and the other training opportunities provided by geothermal institutions in Iceland, Italy, USA, New

TABLE 5: Training opportunities availed by PNOC-EDC personnel

No.	Type	Trainees	Duration	Venue
1.	**PhD.**	**2**		
	Reservoir engg.	1	4 yrs.	NZ
	Geochemistry	1	4 yrs.	NZ
2.	**Masterate**	**16**		
	Reservoir engg.	5	2 yrs.	NZ/USA
	Geochemistry	2	2 yrs.	NZ
	Geophysics	2	2 yrs.	NZ
	Geology	5	2 yrs.	NZ/USA
	Mechanical engg.	1	2 yrs.	NZ
	Structural engg.	1	2 yrs.	Japan
3.	**Diploma**	**50**		
	Geoth. tech.	44	10 mos.	NZ
	Geoth. tech.	5	6 mos.	Italy
	Earthquake engg.	1	1 mo.	Japan
4.	**Specialized training**	**85**		
	Reservoir engg/Well logg.	14	3-6 mos.	NZ/USA/Iceland
	Geology	6	3-6 mos.	NZ/FRG/Iceland
	Geochemistry	13	2-6 mos.	NZ/FRG/Iceland
	Geophysics	4	6 mos.	NZ/Japan/Iceland
	Drilling/Mud engg.	10	1-2 mos.	NZ/Taiw./Iceland/USA
	Well Test/Prodn	7	2 mos.	NZ
	Process engg	2	2 mos.	NZ
	Field mgt.	8	2 mos.	NZ
	Dbase mgt.	1	1 mo.	NZ
	Non-electrical uses	10	1 mo.	NZ/Italy/Iceland/USA
	Corrosion	1	2 mos.	NZ
	CADD	2	1 mo.	USA
	Environmental	7	2 mos.	NZ/Italy/Scotland
5.	**Others**	**16**		
	Energy tech.	6	3 mos.	Japan
	Study tours			
	Environmental	4	2 wks.	NZ
	Process engg.	3	1 mo.	NZ/USA/Europe
	Well logging	2	2 wks.	USA
	Instrumentation	1	2 wks.	USA
	Drilling	-	2 wks.	USA
	Total	**169**		

Zealand, Japan; and other international agencies like UNDP, USTDP and others. Table 6 summarizes the training forecast made for some PNOC-EDC personnel in 1993 as part of itsprogram to sustain the 1993-1996 objectives. The list indicates that only a handful of personnel can avail of the annual foreign training programme compared with the number of people who will operate and manage the new fields. Buning et al. (1991) projected a need to train at least 62 personnel a year to meet the operational demand in 1995. This requirement should now increase five times a year to cope with the fast track development of the different projects. PNOC-EDC is thus faced with severe shortage of experienced personnel and has to multiply its on-the-job training in all its projects. In 1991, international experts endorsed the establishment of a regional training centre in the Philippines to cater to the needs of the Southeast-Asia-Pacific Region (UN/DTCD, 1991). However, for some reasons, the proposed operation of the centre was deferred if not totally shelved. This could have been another training venue of PNOC-EDC if the plan to start its operation in 1992 pushed through. With the uncertainty on the establishment and support of UNDP to this centre, PNOC-EDC will continue to rely heavily on the training opportunities offered by existing international schools in developing its future personnel.

TABLE 6: A sample of PNOC-EDC training forecast for the year 1993

No.	Type	Trainees	Duration	Venue
1.	**Masterate**	**1**		
	Geotech'l. engg.	1	2 yrs.	Thailand
2.	**Diploma**	**6**		
	Geoth tech.	4	10 mos.	NZ
	Geol. survey	1	11 mos.	Netherlands
	Highway design	1	7 mos.	UK
	Planning/Const.			
3.	**Specialized training**	**36**		
	Reservoir engg.	2	6 mos.	Iceland
	Reservoir engg.	2	3 mos.	NZ
	Geochemistry	1	6 mos.	Iceland
	Isotope hydrology	2	3 mos.	IAEA/Austria
	Drilling tech.	1	2 wks.	USA
	Mud engg.	6	7 wks.	USA
	Environmental	8	1 mo.	USA/Japan/Thai.
	Instrumentation	6	2 wks.	USA/Australia
	Maintenance engg.	1	2 mos.	India
	Soil mechanics	1	-	Germany
	Hydrology	1	26 wks.	Spain
	Boiler/Pres.vessel repair	1	-	USA
	Ultrasonics	2	10 days	England
	Mat'ls control/Cost engg.	1	-	-
	Quality assurance	1	5 days	England
4.	**Others**	**8**		
	Seminars/Conf.			
	GRC annual mtg.	4	1 wk.	USA
	Power plant seminar	1	-	USA
	Int'l. jt. power sem.	1	-	-
	Study tours	2	2 wks.	NZ/Indonesia
	Total	**53**		

1.8 Build-operate-transfer projects

The passage of Executive Order 215 in 1989 extricated from Napocor the vested monopoly of generating power in the country. PNOC-EDC, being a developer of many geothermal fields, have made arrangement with Napocor to construct its own power stations to ensure that it can harness power from all its contract areas. PNOC-EDC issued bidding for joint venture and build-operate-transfer projects in the last quarter of 1992 to share investment risk, avail of technology transfer, and allow timely commissioning of power stations. The terms and reference of these arrangements call for a 10-15 year cooperation period after which PNOC-EDC owns and operates the plants. Table 7 shows the summary of the projects under build-operate-transfer arrangements.

TABLE 7: Build-operate-transfer arrangements under negotiation

Project	Capacity (MW)	Contractor	Commissioning date
1. LEYTE-CEBU			
Upper Mahiao	130	Ormat	July 1996
Malitbog	70	Magma	July 1996
2. LEYTE-LUZON			
Malitbog	170	Magma	July 1997
Mahanagdong	165	Cal.Ener.CO.	July 1997
Alto Peak	80	for bidding	July 1997
3. MINDANAO I	40	for bidding	Sept. 1994
Total	**655**		

1.9 Drilling programme

Table 8 shows the drilling programme and the number of wells required to meet the target commissioning and capacity in each geothermal field. The programme calls for drilling a total of 179 wells from 1993 through 1997 that would require an increase in the total number of operating rigs from 7 in 1993 to 9 in 1994. A total of 3 rented rigs will have to be made available to complement the existing rigs of PNOC-EDC. In 1997, the company would have drilled a total of 366 wells in the entire country since its inception in geothermal development.

1.10 Funding requirements

PNOC-EDC negotiates with World Bank (WB), Overseas Economic Cooperation of Japan (OECF), Japan Eximbank to meet the financing requirements of the 1992-1997 development program. A summary of each project financing requirement is shown in Tables 9A and B. The total company's investment in 1993 is distributed as 67.7 million dollars foreign cost and 1.02 billion pesos (37 million dollars) local cost. This would reach maximum in 1995 where about 214 million dollars foreign cost is allocated together with 1.9 billion pesos local cost.

TABLE 8: The drilling programme and planned number of wells to meet the target commissioning and capacity in each geothermal field

	Capacity (MW_e)	Target commissioning	Wells required	1993	1994	1995	1996	1997
A. Exploration and development of fields and power stations								
Bacman I	110	August 1993	0					
Bacman II	40	December 1993	0	0				
Labo	120	1995/1997	21	1	5	8	7	
Mindanao I	120	Sept 1994/1995/1996	20	12	8			
Leyte A	640	July 1996/July 1997	77	10	20	20	20	7
Leyte-Cebu	(200)	July 1996	8	0	2	3	3	0
U. Mahiao	130		8	0	2	3	3	
Malitbog	70							
Leyte-Luzon	(440)	July 1997	69	10	18	17	17	7
Mahanagdong	165		23	4	6	6	5	2
Malitbog	170		24	4	6	6	6	2
Alto Peak	80		18	2	4	5	5	2
Tongonan	25		4	0	2	0	1	1
Palinpinon II	80	Oct 1993	0	0				
N-Negros	40	Jul 1995	12	1	1	5	5	
Sub-Total	1150		130	24	34	33	32	7
B. Replacement wells in production fields								
Tongonan I	112.5		2	1	0	0	1	
Palinpinon I	112.5		3	0	1	1	1	0
Palinpinon II	80		6	2	1	1	1	1
Bacman I	110		7	3	1	1	1	1
Bacman II	40		5	2	1	1		1
Mindanao I	120		2				1	1
N-Negros	40		1				1	
Sub-Total	615		26	8	4	4	6	4
Re-entry wells			23	3	9	3	4	4
Total			**179**	**35**	**47**	**40**	**42**	**15**
Drilling Rigs Required				**7**	**9**	**8**	**8**	**3**

1.11 Environmental management programme

The protection of the environment has always been an important policy of the energy sector since the implementation of the Philippine energy programme in the 70's. In line with this policy, PNOC-EDC maintains an environmental management group and supports strong environmental policies and programs. Its main environmental thrust is to ensure safe, efficient and sustainable use of energy resource to meet the requirements of the present and future generations. To achieve this goal, PNOC-EDC adopts the following environmental policies:

1. Integration of environmental concerns into every planning and decision-making.
2. Acceleration of the development of sustainable and environment-friendly energy resources.
3. Maintenance of sound environmental quality in all energy projects through:
   a) Full compliance with government environmental regulations.
   b) Development of environmental consciousness among company employees, contractors and supporters.
   c) Maximization of benefits to communities around energy projects.

TABLE 9a: The financing requirements of the 1992-1997 development programme, exploration and development of fields and power stations

	Capacity (MW_e)	Commercial operation	1993 MP	1993 M$	1994 MP	1994 M$	1995 MP	1995 M$	1996 MP	1996 M$	1997 MP	1997 M$	Sub total (1993-1997) MP	Sub total (1993-1997) M$
Bacman I	110	August 1993	49.1										49.1	
Bacman II	40	Dec. 1993	59.2	2.5									59.2	2.5
Labo	120	1995-1997	308.6	32.5	233.7	4.6	222.9	7.4	170.3	6.43			935.6	50.9
Mindanao I	120	Aug 1993/1996	270.6	16.4	194.1	23.9	958.2	138.3					1422.8	178.6
Steam field			270.6	16.4	194.1	23.9	51.0	3.9					515.6	44.2
Power station							907.2	134.4					907.2	134.4
Leyte A	640	Feb 96/Dec 97	251.0	14.4	554.9	76.0	600.5	62.8	482.9	30.4	182.7	11.0	2072.1	194.7
Leyte-Cebu	200	July 1996	31.2	2.1	118.5	19.4	175.2	14.8	104.0	6.4			429.0	42.7
(U.														
Leyte-Luzon	440	July 1997	219.8	12.3	436.4	56.5	425.4	48.0	378.8	24.0	182.7	11.0	1643.1	151.9
Mahanagd														
Malitbog														
Alto														
Exp.														
Palinpinon II	80	Oct 1993	43.5	0.9									43.5	0.9
N-Negros	40	Jul 1995	38.5	0.9	146.2	13.9	156.2	6.0	115.1	3.7			456.1	24.5
Total	**1150**		**1020.5**	**67.7**	**1128.9**	**118.3**	**1937.9**	**214.5**	**768.3**	**40.5**	**182.7**	**11.0**	**5038.3**	**452.1**

TABLE 9b: The financing requirements of the 1992-1997 development programme, replacement wells in production fields

	Capacity (MW_e)	Commercial operation	1993 MP	1993 M$	1994 MP	1994 M$	1995 MP	1995 M$	1996 MP	1996 M$	1997 MP	1997 M$	Sub total (1993-1997) MP	Sub total (1993-1997) M$
Tongonan I	112.5	Mar 1983	17.7	0.9					17.7	0.9			35.4	1.8
Palinpinon I	112.5	Jun 1983			16.7	0.9	16.7	0.9	16.7	0.9			50.0	2.9
Palinpinon II	80	Oct 1993	33.3	1.9	16.7	0.9	16.7	0.9	16.7	0.9	16.7	0.9	100.0	5.7
Bacman I	110	Mar/Jun 1993	102.3	2.7	24.1	0.9	17.7	0.9	17.7	0.9	17.7	0.9	179.6	6.2
Bacman II	40	Jul/Aug 1993	35.4	1.8	37.5	0.9	17.7	0.9			17.7	0.9	108.4	4.5
Mindanao I	120	Aug 1995/1996							17.7	0.9	17.7	0.9	35.4	1.8
N-Negros	40	Jul 1996							17.7	0.9			17.7	0.9
Sub-total (1992 price level)	**615**		**188.8**	**7.2**	**95.0**	**3.6**	**69.8**	**3.6**	**104.2**	**5.4**	**69.8**	**3.6**	**526.5**	**23.7**

To ensure control and compliance of government environmental regulations, different permits have to be secured at various stages of project development. These permits are summarized in Table 10.

1.12 Conclusions

The Philippine government has given its highest priority to develop geothermal resources through the year 2000. In this decade, the country will have an installed capacity of 2,483 MW; equivalent to 32% of the total power generation mix. A commercial pilot plant for agro-industrial drying applications will further promote the use of geothermal energy especially in the remote areas. For the first time, build-operate-transfer projects on power generation would take place laying

TABLE 10: Types of environmental permits required in the Philippines

Forest status/Type of permit			Additional requirements
1.	**National park areas**		
	(Site must be excluded from the park before drilling is considered)		
	A.	Exploration permit	Environmental compliance certificate
	B.	Special land use permit	Environmental impact ass. report (EIA)
2.	**Non-park areas**		
	A.	Exploration permit	Waiver from Mine Lessee
	B.	Road right-of-way	Plans and programs
	C.	Tree cutting	Payment of rental fees
	D.	Special land use	EIA
			Feasibility study

the ground for more private participation and accelerated development of geothermal energy. The country will witness the peak of geothermal growth during this decade as development on most of the promising geothermal areas will take place during this period. The Philippines would thus achieve at the end of this century that distinction of being the world's largest producer of geothermal energy; and subsequently support the country attain its goal of becoming a "newly industrialized country" by the year 2000.

2. RESERVOIR ENGINEERING ASPECTS OF ASSESSING GEOTHERMAL RESOURCES IN THE PHILIPPINES

2.1 Introduction

Assessment of geothermal resources requires input and involvement of personnel from several disciplines. In the early stages of exploration, evaluations of geothermal prospects are based mainly on the results of geological, geophysical and geochemical surveys and investigations. The inputs that are reckoned from surface observations and measurements from these disciplines are examined to infer the nature, characteristics and the probable size of the geothermal system, and if possible construct a hypothetical model(s) of the field. The exploration model(s) usually represents the probable origin and source temperature of fluids that is used in deciding whether the prospect merits drilling and/or additional geoscientific surveys.

This chapter demonstrates the reservoir engineering aspects, techniques and methodologies adopted by PNOC-EDC in their assessment of geothermal resources. These aspects include the type of tests, downhole surveys, discharge stimulation techniques, resource assessment techniques and other relevant practices essential in characterizing and determining the capacity of a geothermal field. Many of these techniques have been derived from the company's operational experience in 15 years, and the technology transfer programme between Philippine engineers and international experts who have directly or indirectly contributed in the geothermal development in the country.

2.2 Downhole measurements

Downhole measurements are conducted in geothermal wells to gain subsurface information on the physical characteristics of geothermal systems. Temperatures and pressures are measured directly using mechanical gauges and electronic instruments. On the other hand, permeability, storage capacity and other reservoir and formation properties are calculated from results of different test and measurements down the hole. PNOC-EDC conducts the following tests and measurements as standard procedures in all the fields that it develops:

Static Formation Temperature Test (SFTT)
Static formation temperature test is usually conducted on the first three wells in new exploration sites to derive an estimate of the formation temperatures while drilling. The estimated temperatures obtained during this test are used to determine the depth in which the 9⅝" casing shoe will be set. As a standard procedure, PNOC-EDC defines a minimum temperature of 220°C in setting the casing shoe depth to limit the entry of fluids in the well below this temperature. The static formation temperature test results also determine if temperature inversion exists in the well and decides whether to modify the drilling target or terminate drilling. This information is equivalent to a $1.5 million decision as it is difficult to rationalize completing the well drilling if we could not attain the objective of intersecting good temperatures.

Roux et al. (1979) describe the principles involved in the analysis and conduct of the test. This test is done by monitoring the temperature build-up for at least 8 hours at predetermined depths after circulating for at least 12 hours. In particular, the test has to be conducted at sections where there are no circulation losses to ensure that only heat conduction governs temperature recovery during the test.

A simplified and empirical technique of analyzing static formation temperature test data was developed by Brennand (1983) based on the data from 35 geothermal wells in the Philippines. This approach does not apply any correction factor as required by Roux et al. (1979) but the results match very well with their methods. Statistics also indicate that the estimated temperatures are within 5°C of actual temperatures - with only 15% of the results deviating by 15°C (Sarit, 1989). Hence, this method becomes the most reliable technique of predicting formation temperatures while drilling. Figure 16 illustrates the static formation temperature test results based on the two methods.

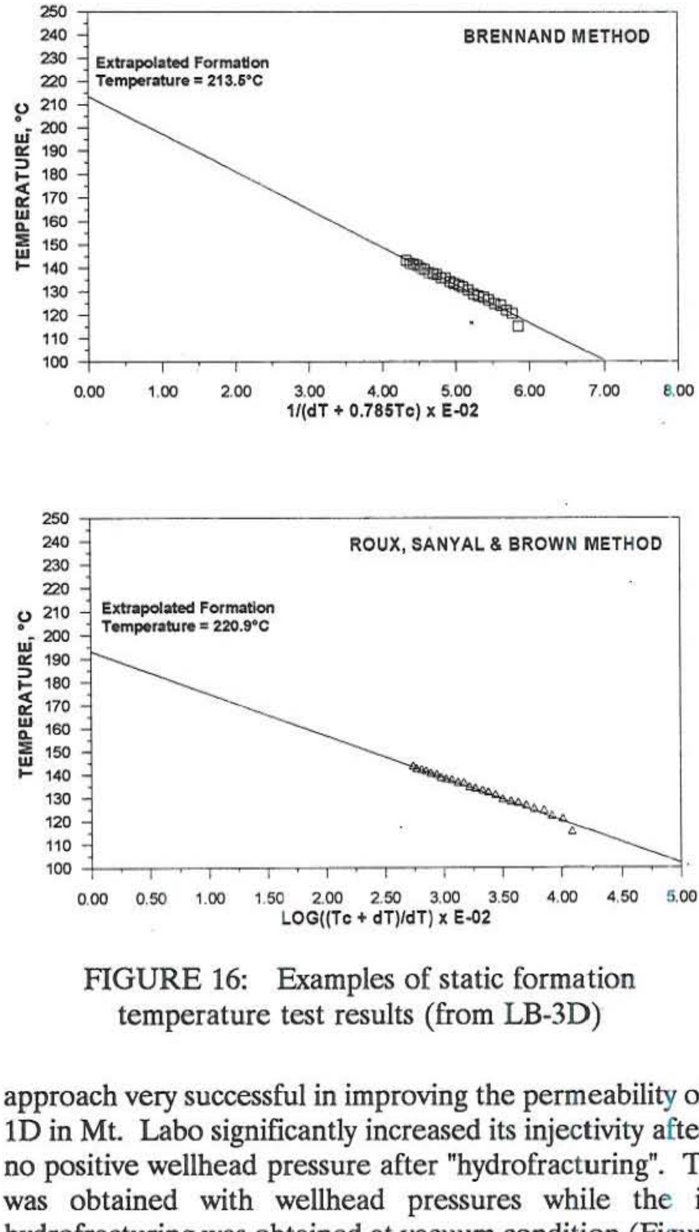


FIGURE 16: Examples of static formation temperature test results (from LB-3D)

Completion tests and heat-up surveys
These tests are conducted immediately after drilling completion. The completion test comprises of running waterloss surveys, injectivity test and pressure fall-off test. The water loss surveys are conducted by lowering temperature gauge down the hole while pumping water at constant rate to determine the zones where the fluids are being lost. The loss or permeable zones identified from this test indicate the likely feed zones that will yield steam during production.

The injectivity test is run by lowering a pressure gauge at fixed point in the hole usually across the main permeable zone; and monitoring for at least 1 hour the pressure response at 3 pump rates. A slope of the plot of injection rate versus pressure will yield the injectivity index of the well; a measure of the overall well permeability. In general, we have used the results of injectivity test to determine whether "hydrofracturing" should be done in a well to improve its permeability. We have found this approach very successful in improving the permeability of many wells; and to cite a case, well LB-1D in Mt. Labo significantly increased its injectivity after 24 hour pumping as the well registered no positive wellhead pressure after "hydrofracturing". The higher injectivity value of 46 l/s-MPa was obtained with wellhead pressures while the injectivity value of 25 l/s-MPa after hydrofracturing was obtained at vacuum condition (Figure 17). The result had been very positive as the well was converted from being a tight well to a good producer.

Pressure fall-off test is a continuation of the injectivity test conducted by monitoring the pressure response after halting water injection. Analysis of the data yields transmissivity index that also connotes well permeability - expressed in darcy-metres. The results also determine whether mud damage took place in the well during drilling as indicated by a positive skin factor.

Heat-up surveys comprise downhole and temperature measurements are carried out after shutting the well from completion test; usually at interval 1, 3, 6, 12, 24, 30 and 45 days depending on the duration of temperature recovery required in successfully discharging a well.

Temperature
Temperatures around the wellbore cool down as a result of drilling and pumping during completion test. In impermeable horizons, conductive cooling takes place, whereas in permeable zones, quenching occurs as water looses into the formation. Monitoring the temperature recovery of the well during the period unmask several characteristics of the well that mirror reservoir condition. This is possible because fluid dynamics during the process and until it attains stable condition will reveal the state of fluids penetrated by the well in the reservoir. Conduction and advection govern the heat transfer between the rock and the fluid; with conduction taking place on impermeable horizons and advection prevalent on permeable zones. Many times, heat-up data confirm permeability indications from water loss surveys but, in some cases, we can also observe more permeable zones than those observed in the completion test (Figure 18). Wells with poor permeability are commonly very slow in heating while permeable wells with strong internal flow become heated up in only a few hours. Similarly, the zone that accepts the bulk of fluid during injection may take longer time to warm up and generally chases the other zones during the stabilization period.

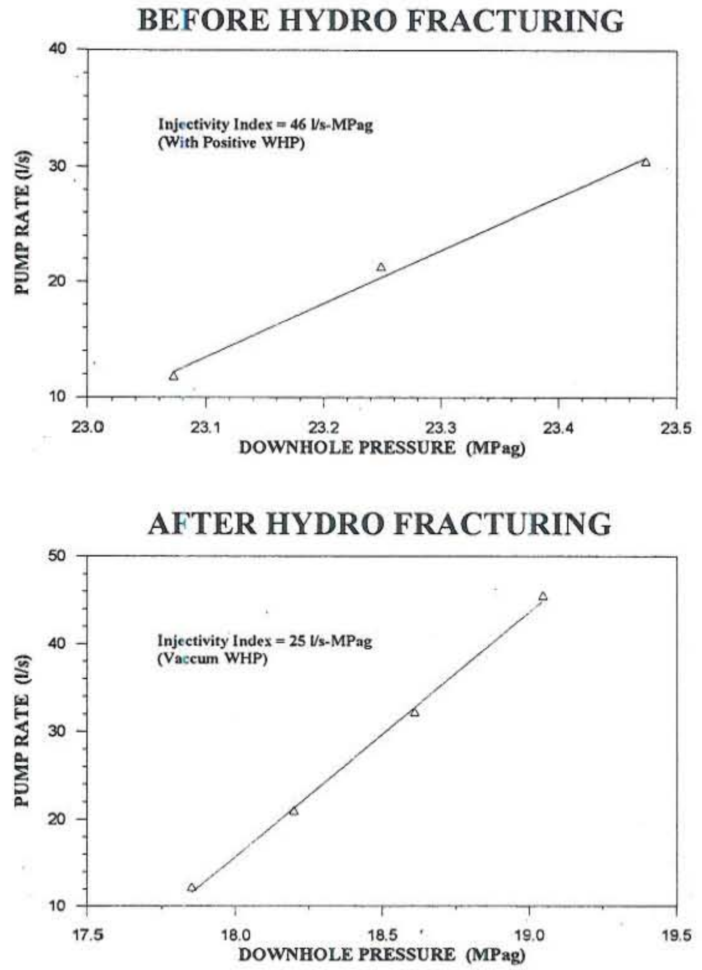


FIGURE 17: Examples of results from injectivity tests (LB-1D), before and after hydrofracturing

Some of the prominent features observed in the wells during heat-up can be described as follows:

- Upflowing profile approaching or corresponding to the boiling point curve of water
- Downflowing fluids suggesting isothermal profile from feed point to the exit point
- Temperature reversal common in outflow areas
- Linear temperature gradient on impermeable zones especially opposite the cased-off section of the hole

Figures 19, 20, 21 and 22 demonstrate the different features described above. The case on MG-4D down flow merits special attention because we drilled this well in an area where we inferred the maximum temperature to be above 290°C. Results of temperature surveys and fluid inclusion analysis indicate entry of cold water at -600 m through the Manban fault that serves as conduit to the ingress of this cold water. However, the measured temperatures only reached 160°C because the down flow masks the projected temperatures from the entry point to the exit point. This information led us to design a work-over that would plug this entry point and possibly restore the bottomhole and its temperature to convert it into a production well.

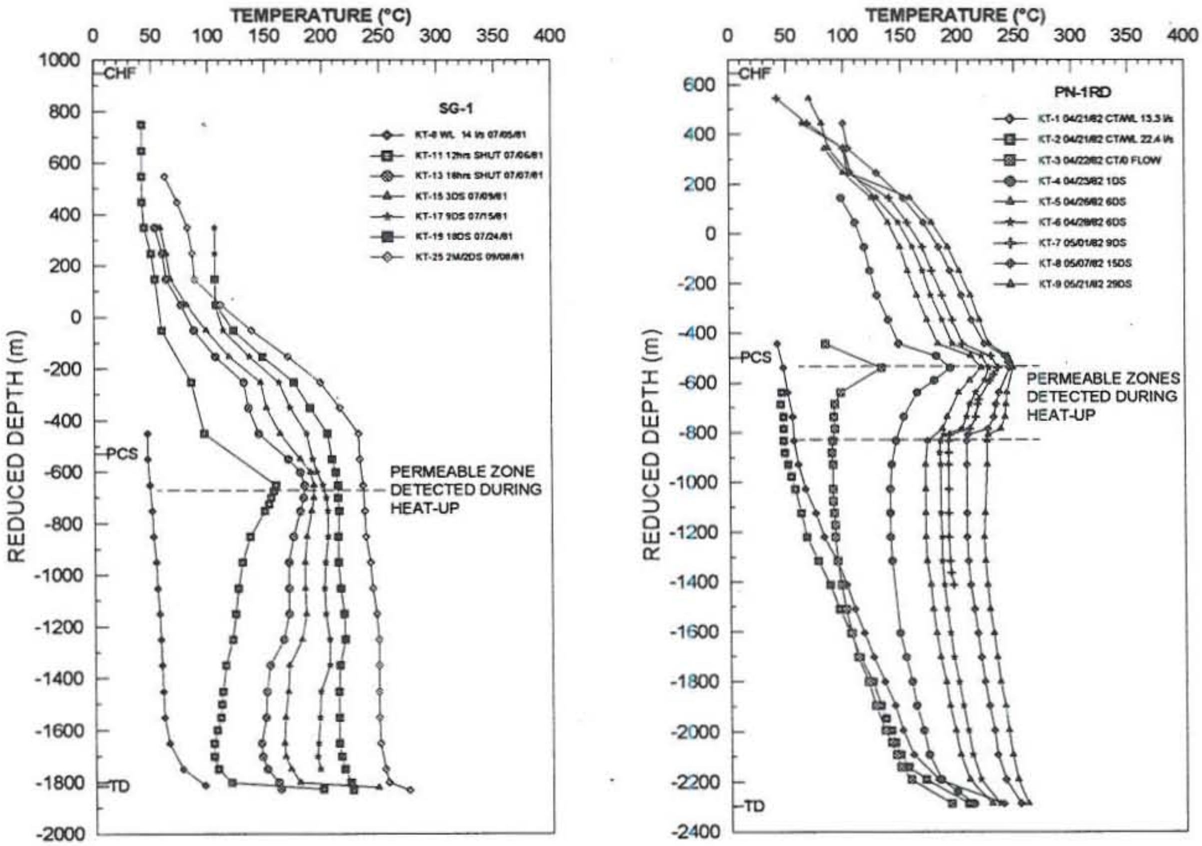


FIGURE 18: Examples of heat-up data identifying permeable zones

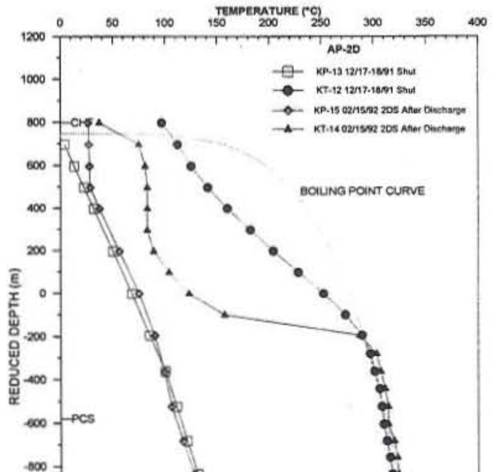


FIGURE 19: Example of temperature profiles showing boiling in the wellbore

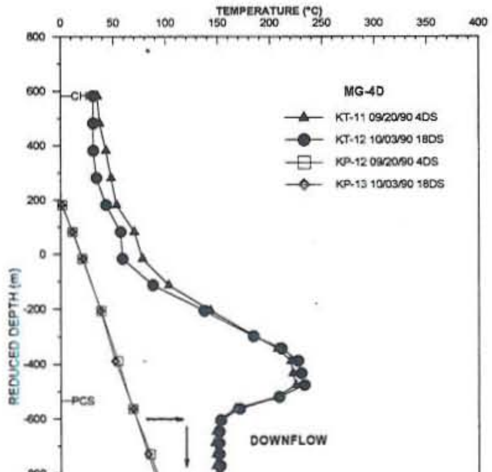


FIGURE 20: Example of temperature profiles showing downflow in the wellbore

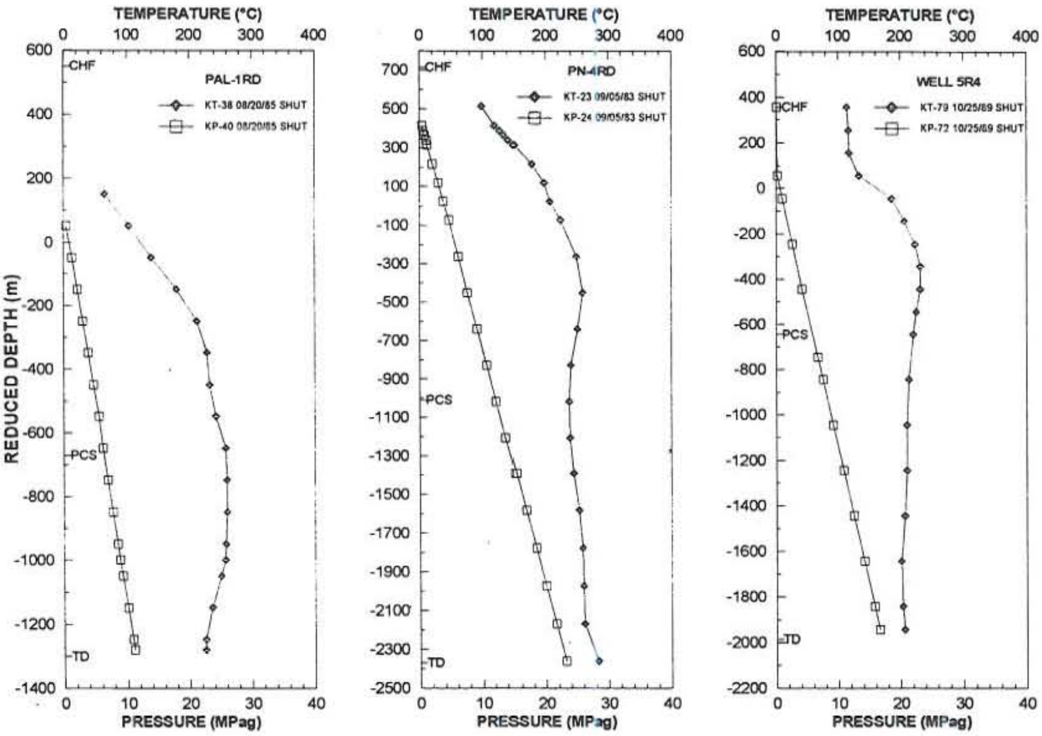


FIGURE 21: Examples of temperature profiles with reversals at the bottom

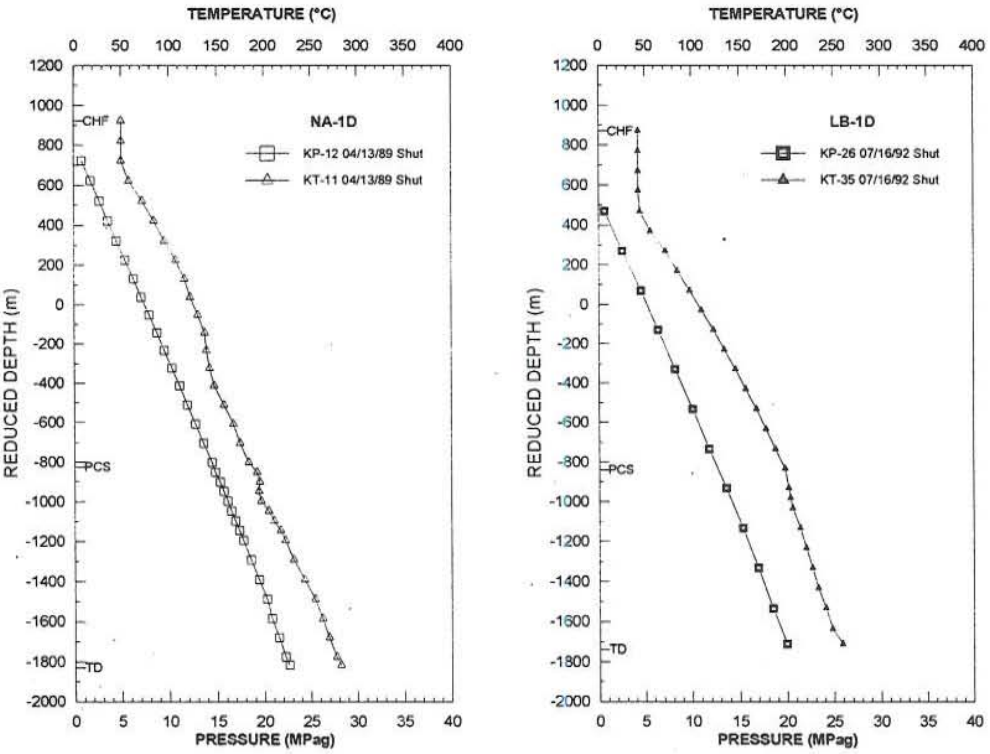


FIGURE 22: Examples of wells with linear temperature gradient

Pressure

Grant (1979) and Stefansson and Benediktsson (1980) discussed in detail many aspects of pressure changes during the heat-up of the well. Their literature clearly illustrate the concept on pivot point - the depth in the well where the pressure remains stable because it approximates reservoir pressure. These aspects are not discussed further here, but the reservoir pressure gradients typical in Philippine geothermal fields is briefly described (Figure 23).

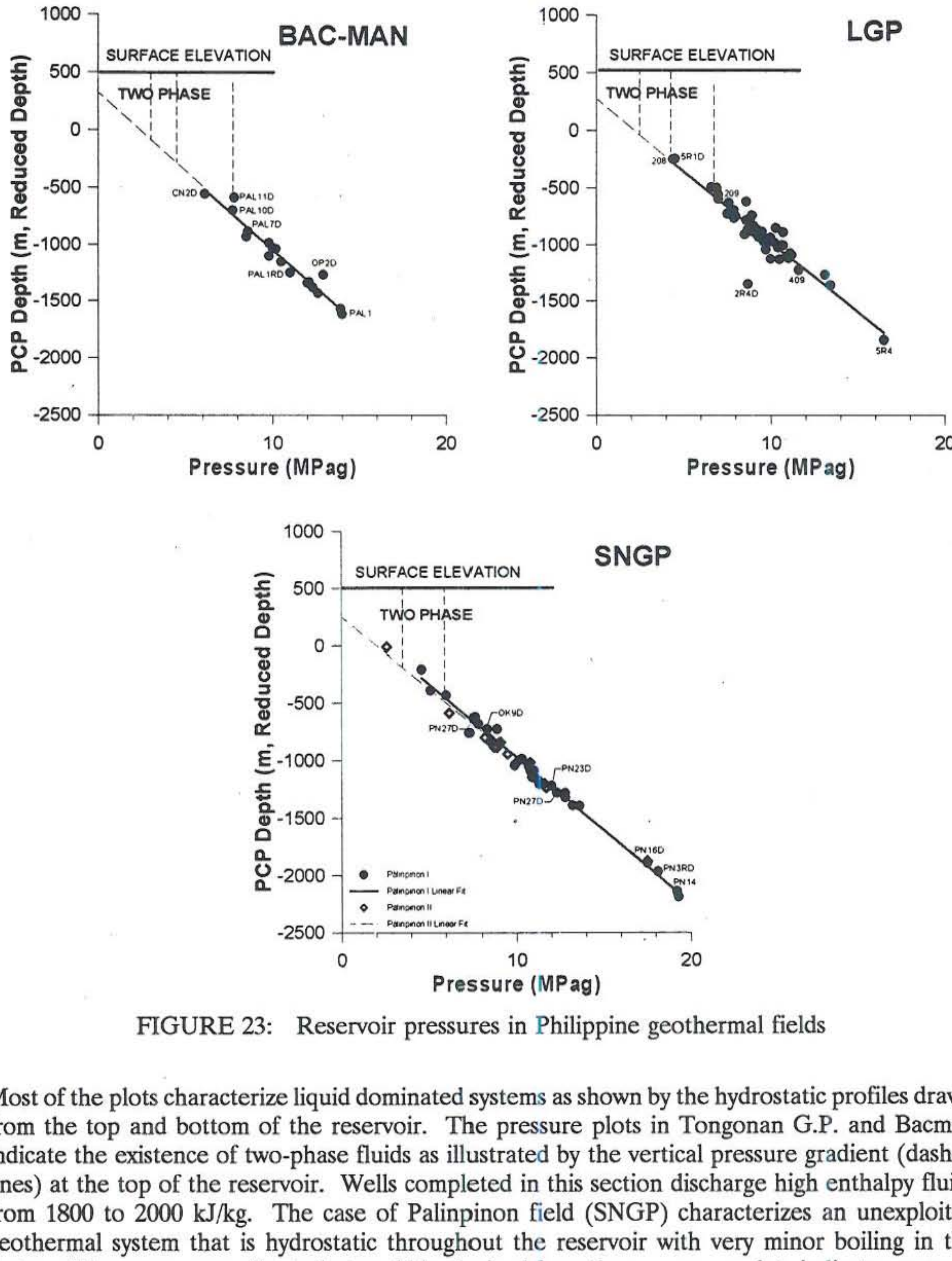


FIGURE 23: Reservoir pressures in Philippine geothermal fields

Most of the plots characterize liquid dominated systems as shown by the hydrostatic profiles drawn from the top and bottom of the reservoir. The pressure plots in Tongonan G.P. and Bacman indicate the existence of two-phase fluids as illustrated by the vertical pressure gradient (dashed lines) at the top of the reservoir. Wells completed in this section discharge high enthalpy fluids from 1800 to 2000 kJ/kg. The case of Palinpinon field (SNGP) characterizes an unexploited geothermal system that is hydrostatic throughout the reservoir with very minor boiling in the system. The pressure gradients that could be derived from these pressure plots indicate reservoir temperatures in the range of 270 to 280°C.

The other conclusion that can be drawn from the heat-up monitoring is that wellhead pressure develops rapidly in wells completed with vapour and gas-rich zone, compared with those wells from absolutely liquid-filled reservoir that develop pressure (if any) only due to minor boiling at depth.

2.3 Discharge stimulation

Most of the geothermal fields in the Philippines are situated at elevations of 800 to 1000 m a.m.s.l. and, because they are mostly liquid dominated systems, water levels stand from 400 to 1000 m from the surface. These wells have difficulty initiating their own discharge with the exception of wells that tap from vapour dominated zones. The low temperatures at the upper portion of the holes aggravate the difficulties as it will require more energies to overcome the heat losses from the wellbore to the surrounding rock. Our experience is that we could have not discovered and developed some of our geothermal fields if we failed to adopt the appropriate stimulation techniques in discharging our discovery wells. I want to emphasize that at least one of the first three deep exploratory wells in an area should be flow tested to come up with a preliminary resource assessment and justify development drilling program.

Air compression
Stimulation by air compression is the cheapest among the various stimulation techniques adopted in the Philippines. This method only involves mobilizing and connecting a high-volume, high-pressure air compressor to the wellhead for stimulation and inject air to compress the water column inside the well. By depressing the water column to a much lower depth, where downhole temperatures are higher, the water gets heated up. If the fluid heats up to sufficient temperature, it should overcome pressure and heat losses as it goes up the wellbore; and once the well is opened, the flow should ultimately reach the surface and results in a successful discharge attempt.

A_f/A_c factor
Figure 24 shows typical downhole profiles of geothermal wells with the areas A_f and A_c plotted. A_f is the area covered by the temperature profile with depth at which to depress the water column by air compression. This area represents the energy available for the fluid to absorb if the water column is depressed to that depth. A_c is the area covered by the temperature profile with depth below 100°C, i.e. boiling temperature of water. This area represents the resistive energy that the fluid should overcome as it goes up the well upon initiation of discharge.

Compilation of A_f/A_c ratios of various wells in Philippine geothermal fields yield a cut-off ratio at which a well can be confidently predicted to discharge successfully after air compression stimulation. A well with an A_f/A_c ratio of over 0.85 will likely discharge successfully after stimulating by air compression. A well with an A_f/A_c ratio of less than 0.70 will likely not discharge using air compression technique; hence, adoption of other technique. Wells with an A_f/A_c ratio between 0.85 and 0.70 may or may not successfully discharge with air compression stimulation.

Two-phase injection
Two-phase injection involves connecting the well to be discharged to a two-phase fluid source. This may be a portable boiler, such as the Clayton Boiler E-500 used by PNOC-EDC; or, two-phase fluid from a neighbouring discharging well. By injecting hot fluid into the well, the casing is heated up to reduce the heat losses by the discharging reservoir fluid. At the same time, the two phase fluids pressurize the well providing enough potential for the well to discharge. The main limitation in using the boiler is the cost. Mobilization and rig-up of the portable boiler take

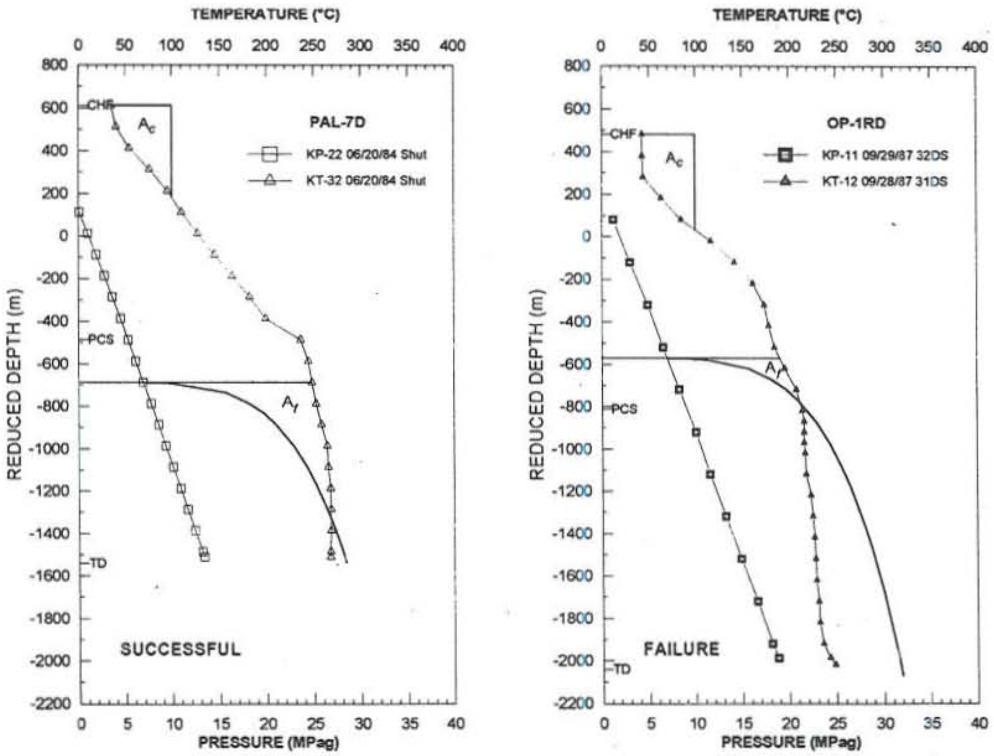


FIGURE 24: Analysis of temperature profiles for the application of air compression techniques in discharge stimulation

up most of the cost (about \$30,000-50,000).

Connecting a two-phase stimulation line from a discharging well, on the other hand, involves piping and installation costs, and usually takes longer to prepare.

Wells that have been stimulated by two-phase injection, particularly through boiler stimulation, are usually those with deep water level (usually below 500 m). These wells may also have their feed zones deep in the reservoir and their temperature gradient or downhole temperatures very low, that large heat loose to the surrounding as reservoir fluids flow through the wellbore during initial discharge.

Examples of cases on the successful use of boiler stimulation are those of OK-5, OK-7D, OK-9D (in Palinpinon), Pal-1RD (in Bacman) and MB-3 (in Tongonan). Figure 25 shows the cases where boiler stimulation was successful while Figure 26 shows cases where the boiler stimulation failed to discharge the wells. In all cases, air compression did not work due to the limitations described above. In the case of Palinpinon wells, cold downflow occurring at the top zone suppresses the flow from the hot bottom zone preventing the latter from initiating the flow (kick) required to sustain a continuous discharge. To do that, the downflow at the top zone should really be heated up to 193°C to effect its unloading to the surface. By boiler stimulation, these limitations were overcome and the wells were successfully initiated to discharge. These wells have rated capacities of 10 MW. PNOC-EDC was already on the verge of abandoning the area because of the many unsuccessful discharge attempts in OK-5; until the boiler was used and became successful. In some cases, however, boiler stimulation did not succeed. There are several reasons for the failures. These include

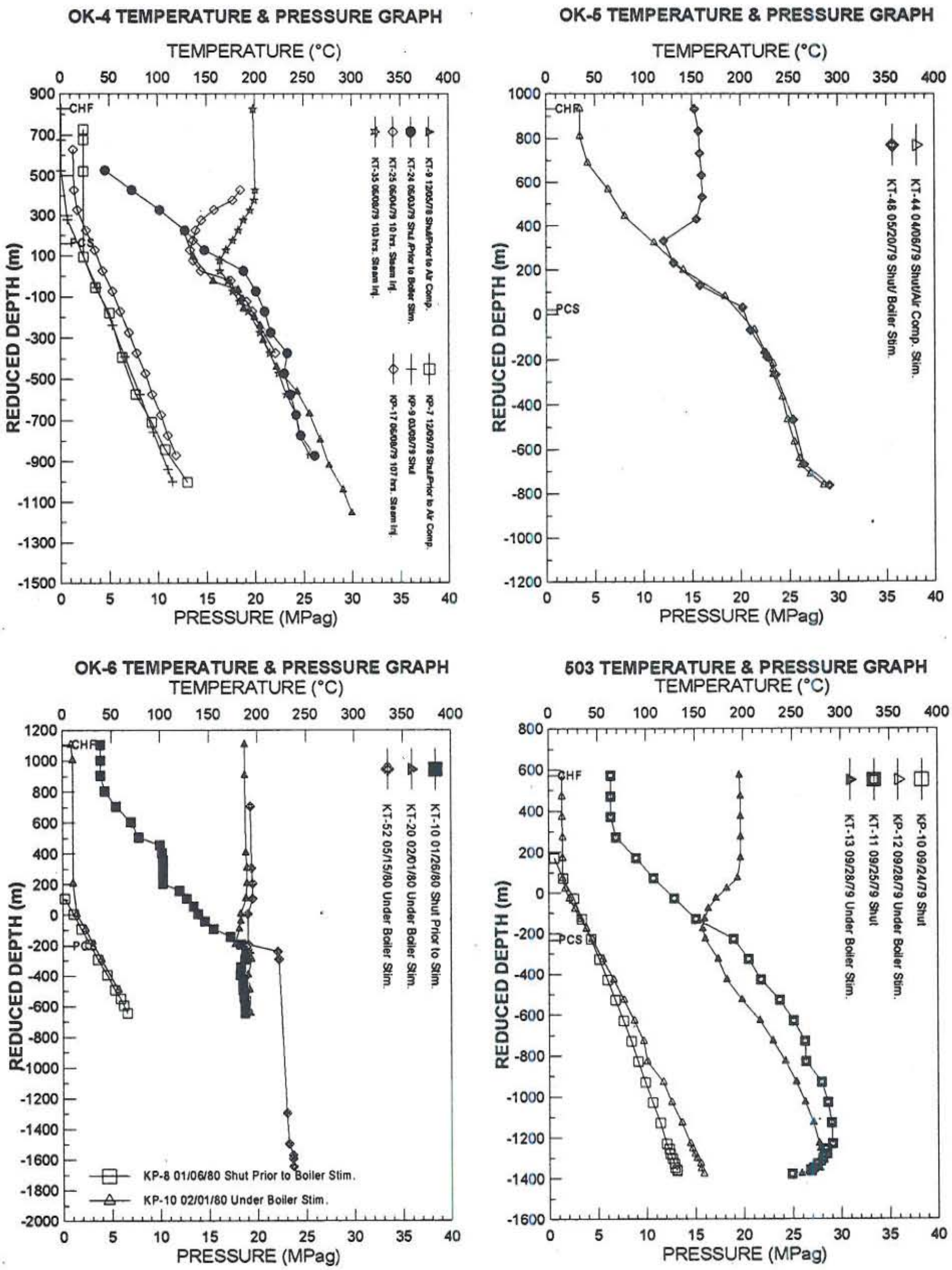


FIGURE 25: Examples of wells successfully stimulated by steam injection

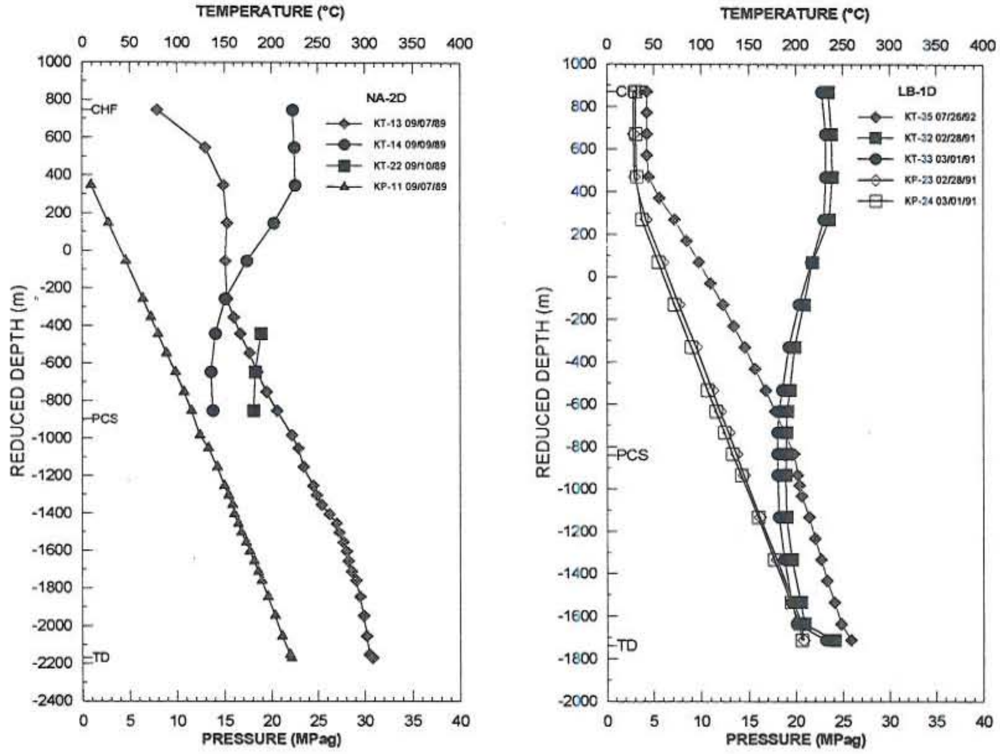


FIGURE 26: Examples of wells where boiler stimulation attempts failed

(a) not attaining sufficient temperature (and pressure) of the injected two-phase fluid to heat up the upper portion of the casing, as in the case of NA-2D in Mt. Natib;
(b) boiler breakdown during actual stimulation operation as in the case of LB-1D in Mt. Labo;
(c) poor permeability of the well as in the case also of NA-2D.

Gas lifting
Gas lifting involves injection of air or nitrogen gas at high volume and high pressure using coiled tubing lowered into the well at a depth below the water level - equivalent to the depth of water level and the surface. By injecting air or nitrogen downhole, bubbling of the water column occurs, reducing the fluid density and causing it to expand, thereby initiating the fluid to rise up. Although this method is cheaper than 2-phase or boiler steam injection, it is more expensive than air compression because it involves more equipment (Figure 27).

Gas lifting is a standard method used in the oil industry for producing oil wells that have stopped producing by themselves because of severe pressure drawdown in the reservoir. Gas lifting technique was successfully carried out in wells LB-1D and LB-3D in Mt. Labo. LB-1D was a good case to mention because all indications point out that this well would not sustain a discharge even if we succeed in lifting some of the fluids to the surface. The boiler stimulation failed twice after attaining critical temperatures at 197°C. We were supposed to abandon the area because failing to flow this well, which was interpreted to be drilled in the upflow region, already reduced the chances of discovering better areas for further development. However, the anomaly in the area is very big and there are still open areas for drilling as in LB-3D. There were no losses throughout the hole during drilling at LB-1D. The well would not accept fluid at low pumping pressure during the completion test, except after the hydrofracturing. As shown in Figure 22, the conductive temperature gradient is typical of wells with poor permeability and thus would have a very slim chance of discharging. However, after unloading the top 1300 m of cold water column during the gas lifting, the bottom zone at -1600 to -1700 m kicked and the well successfully discharged with 4 MW rating. Similarly, well LB-3D initiated its flow through gas lifting. It would never have discharged with air compression or boiler stimulation. The reservoir is very deep, at -1000 to -1600 m and the temperature gradient at the top is cold and conductive. The only condition that the well bottom would kick and sustain discharge to the surface is by unloading the top column of cold fluid.

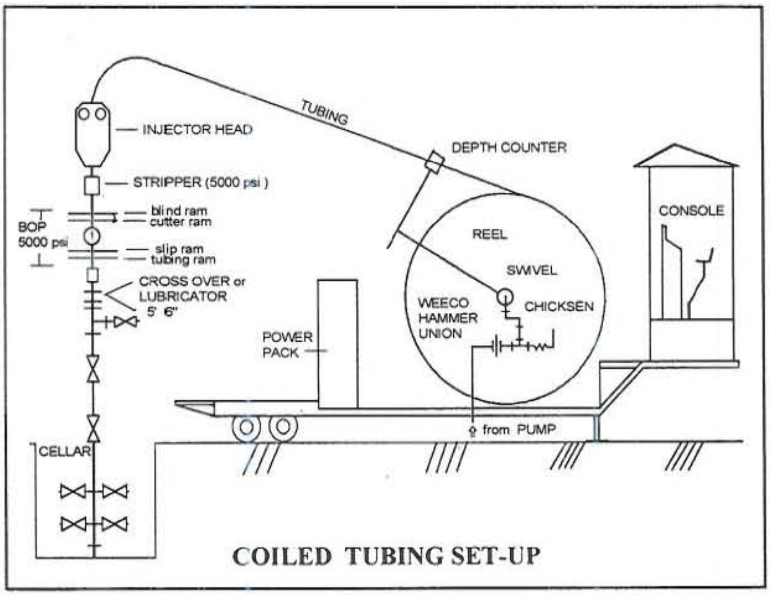


FIGURE 27: A typical set-up of a coiled tubing unit for gas lifting stimulation

With this success in Mt. Labo, gas lifting is now favoured over boiler stimulation particularly in discharging wells that have a) tight permeability, b) very deep water levels and c) constant or linear temperature gradient at depth, similar to LB-1D and LB-3D.

Factors that should be considered in programming well stimulation:
Water column depth. The flowing fluid will encounter more pressure and heat losses as it goes up the well if the water level is deeper. The well would require higher pressure and temperature to initiate discharge with boiler and air compression. On the other hand, more liquid nitrogen and higher pumping pressure may be needed in gas lifting.

Downhole pressure. The higher the pressure at which the water column was depressed, the higher the potential of the discharge fluid to overcome the losses that will be encountered as it goes up the well. However, the pressure to be required to attain the high potential should not exceed the pressure rating of the well casings. Moreover, the maximum pressure that can be attained during compression will depend on the depth of the casing. Once the water level is depressed beyond the casing shoe, air may escape to the formation.

Downhole temperature. The higher the temperature of the water column heated up down the well, the greater the chance for the well to discharge, since sufficient energy will be available to overcome heat losses along the casing.

Casing configuration. The smaller the well casing, the larger the pressure loss that the upflowing fluid will encounter. This will necessitate higher initial pressure to overcome the losses.

2.4 Bore output measurements

The ultimate test whether an area is suitable for development or not is to find out whether the completed wells shall be able to flow at commercial quantity. Besides, it is critically important to determine that the chemical characteristics of the fluids are suitable for production. The uncertainties involved in developing a field are usually reduced if the test data supports the plant capacity that can be committed through the evaluation of the relative output and performance of the different wells. As it is, the strength and performance of the wells during testing serve as the foundation for the decision to commit a certain area for development. We then validate the test results against other geoscientific findings, as well as the varied experience gained from other fields.

PNOC-EDC adopts a typical 3 month period in testing all its wells. The duration is usually longer if the well under test is an exploration well and shorter if it is an in-field well. For new areas, long term duration is implemented to fully characterize them and obtain the confidence on the production sustainability of the field. On an in-field well, a long test duration is not necessary because of the information already available from adjacent wells.

In particular, the wells are tested to:

- Determine the output characteristics of the well in terms of mass flow, enthalpy, dryness and potential.
- Determine the effects of varying the wellhead pressures on the output characteristics.
- Confirm the location of permeable zones obtained from completion test and heat-up period.
- Determine the interaction between permeable zones under changing WHP.
- Measure the drawdown or changes in the productivity index with time.
- Check the fluid chemistry and non-condensable gases of the well.
- Determine the appropriate interface pressure for the power plant.

Figure 28 shows the difference in output trend of wells AP-2D and OP-4D in Alto Peak and Bacman II areas respectively. These two wells show contrasting trends and may well represent the nature of recharge encountered by the two wells; an increasing trend for OP-4D as shown in the last stage of the discharge, and, an increasing enthalpy throughout the discharge period as well as a declining output trend for AP-2D at full bore discharge (FBD) condition, Both wells have temperatures of more than 300°C. The encouraging result on OP-4D indicates that the area has very high potential for production, whereas, some conservatism should be given on interpreting the AP-2D results. We find the response of OP-4D consistent with many big wells in the Philippines; 406 (13 MW_e), 209 (23 MW_e) and MG-7D (13 MW_e) in Tongonan as these wells cleared up during discharge. The full bore discharge of AP-2D is equivalent to 25 MW with a 9⅝" casing. However, this output declined to 17 MW when a 7" sleeve liner was run inside to seal the leaking 9⅝" casing. AP-2D is one of the most prolific wells in the Philippines. It has, however, demonstrated a decline at fully open condition; both in WHP and mass flow. The well achieved flow stability only after it was choked to A3 and A1 backpressure plates. It is thus likely that this well has to be tested longer than usually programmed to confirm whether the recharge in the well is comparatively smaller than the well can actually deliver.

Table 11 shows a summary of bore output data of Bacman wells that will supply the requirement of the power plant. It also shows the non-condensable gas content of the fluids that is used in determining the operating pressure, interface data and the gas extraction system of the power plant.

Figure 29 also shows the output curves of wells CN-1 and OP-6D in Bacman indicating that the discharge output are wellbore and formation controlled. The output is said to be wellbore controlled if the size of the wellbore limits the production of the hole. This is normally observed in areas where the permeability is very high. A big hole drilling programme is recommended if this condition exists, i.e., using 13⅜" casing as production casing and 9⅝" as the liner. The output is

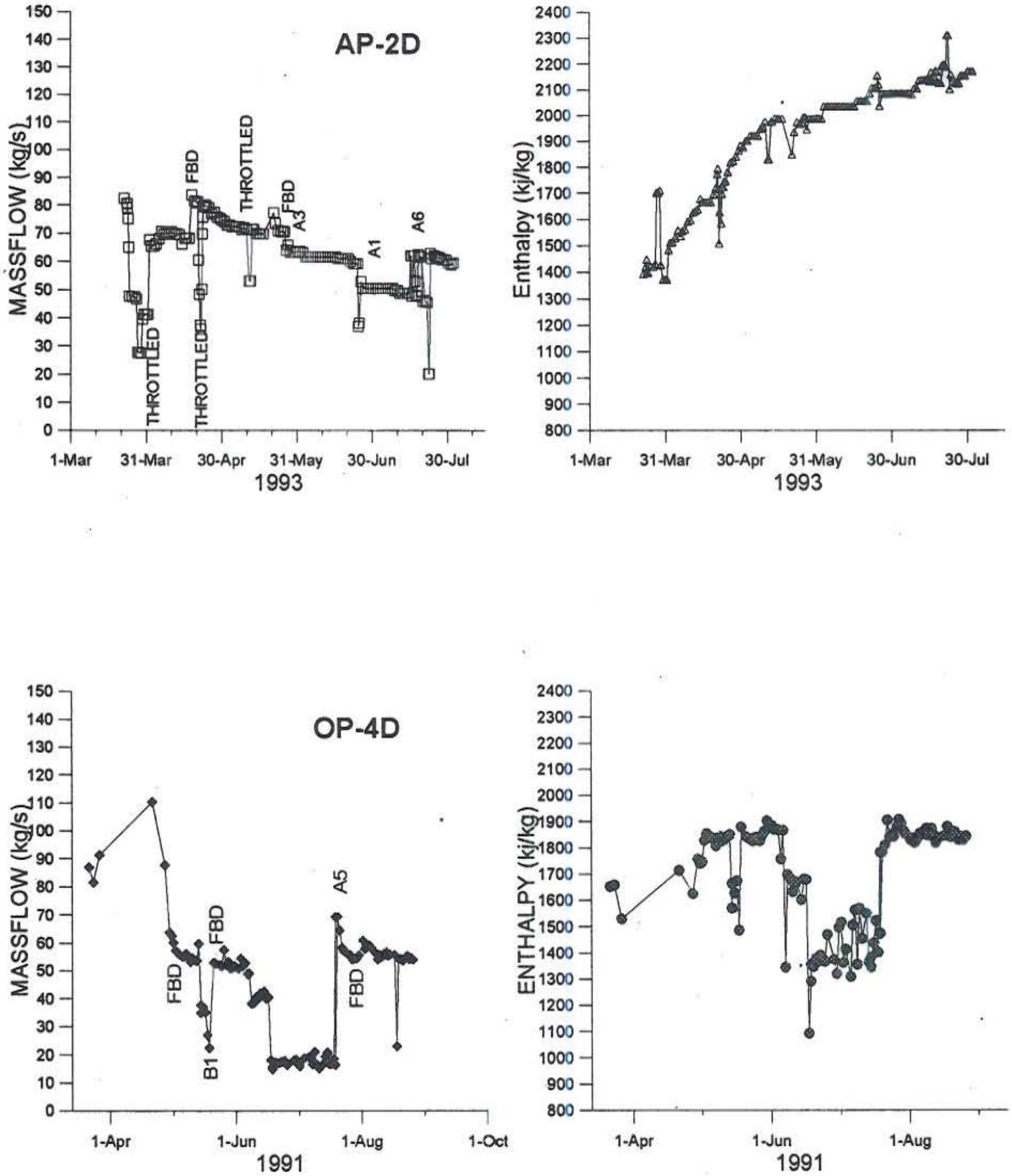


FIGURE 28: Examples of output trends of two big wells in the Philippines

said to be formation controlled if it is the formation permeability that limits well production. In a typical plot of mass flow versus WHP, the mass flow does not change significantly with increasing WHP.

TABLE 11: Summary of bore output data of Bacman wells

Well	Enthalpy (kJ/kg)	Mass flow (kg/s)	Steam flow (kg/s)	Water flow (kg/s)	MW_e	% NCG
Pad C:	**1.0 MPaa separator pressure and 1.03 MPaa WHP**					
PAL-2D	1505	37	13.6	23.4	6.2	8.6
PAL-7D	1290	22	5.8	16.2	2.6	2.3
Average	1424					6.7
Sub-total		59	19.4	39.6	8.8	
Pad H (L):	**1.0 MPaa separator pressure**					
PAL-3D	1330	51	14.4	36.6	6.5	1.6
PAL-4D	1365	35	10.5	24.5	4.7	5.1
PAL-9D	1360	33.5	9.9	23.6	4.5	1.7
Average						2.7
Sub-total		119.5	34.8	84.7	15.8	
PAL-10D	1440	36	11.9	24.1	5.4	6.3
PAL-13D	1540	63	24.1	38.9	11	2.2
PAL-15D	1450	49	16.5	32.5	7.5	2.9
Average	1486					3.3
Sub-total		148	52.5	95.5	23.9	
PAL-8D	1670	81	35.3	45.7	16.1	5.5
PAL-11D	1540	65.5	24.3	41.2	11	5.6
PAL-12D	1300	54	13.5	40.5	6.1	2.7
PAL-14D	1350	130	35.7	94.3	16.2	2.2
Average	1458					4.1
Sub-total		330	106.8	221.7	49.3	
PAL-1	1085	26	4.1	21.9	1.9	2.2
All pads						
Average	**1428**					**3.9**
Total		**683**	**219.6**	**463.4**	**99.7**	

Bore output measurements taken before field exploitation serve as the baseline data in making comparison of the future response of the reservoir. PNOC-EDC continuously perform this test, even during production, to regularly monitor wells' output, and to programme well replacement or work-over when needed.

2.5 Reserve estimation

Upon completion of well drilling and testing, PNOC-EDC undertakes preliminary resource assessment of a given area. The preliminary assessment applies to the evaluation of at least three wells usually programmed in a new exploration area. The results of this preliminary resource assessment should indicate whether development drilling could go on and, if so, should identify the probable targets of future wells. In many cases, this study also includes an initial estimate on the capacity of the field. Update of a resource assessment is prepared as more wells become available.

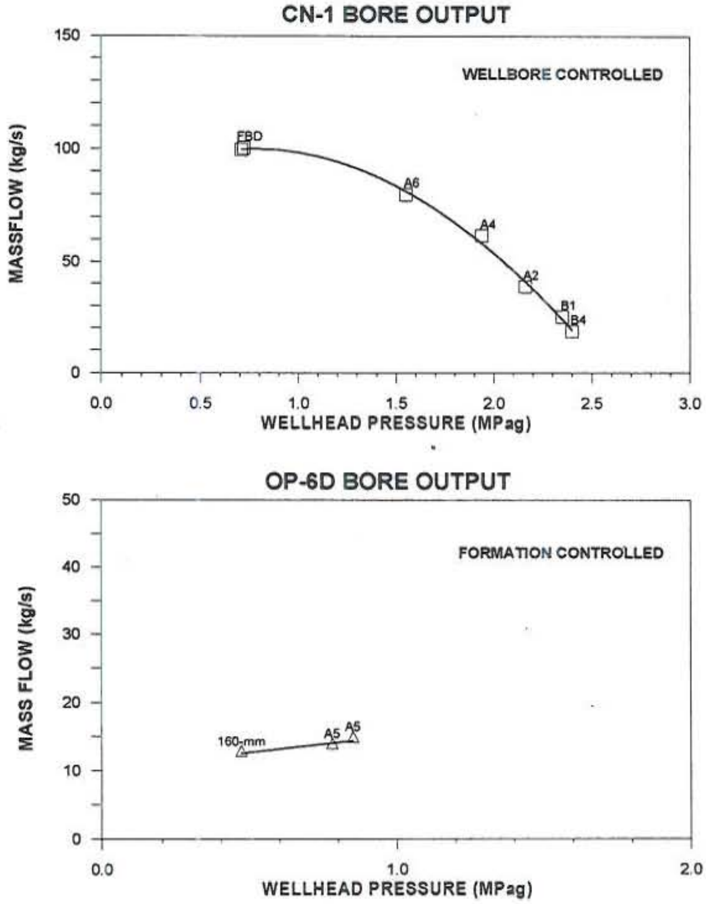


FIGURE 29: Examples of wells with wellbore and formation controlled output

Reserve estimation is one of the main thrust of reservoir evaluation. Any development can not continue without the assurance that the field has the reserve capacity to produce over the desired life of the field. The three methods usually applied in the estimations of a potential reserve of a geothermal resource, without a production history, are volumetric method (stored heat method), lumped parameter model and distributed parameter model (numerical simulation) (Mesquite, 1991). The most appropriate method of calculating the potential reserve in an area where a 3 well drilling programme has been completed is through the volumetric method. This method involves calculation of the heat-in-place in the rock and converting it to equivalent power using recovery factors and conversion efficiencies. White and Williams (1975), Muffler and Cataldi (1978) and Sorey et al. (1982) describe in detail the principles and assumptions involved in computing the stored heat available in the reservoir. However, their technique does not directly illustrate the uncertainties involved in the determination of each rock and reservoir properties. For example, only a single value is assumed for a possible wide range of values that can be assigned for porosity; volume; recovery factor; rock and fluid specific heat and density; conversion efficiency and other parameters used in the estimation.

Monte Carlo Simulation
In their review of PNOC-EDC resource assessment on the Upper Mahiao and Malitbog sectors of the Tongonan geothermal field, Mesquite (1991) applied the Monte Carlo simulation to deal with the complex scenario that describe the mathematics of known parameters but with uncertainty or probability distribution. The experts provide the uncertainty distributions on every parameter involved in the analysis of the normal form of mathematical equation used in estimating the reserve potential (Equation 1). A random number generator then solves the algorithm relating the uncertainty distribution by randomly accessing the values from each distribution individually many times. The result is an overall probability distribution for the reserve estimate that quantitatively incorporates the uncertainties involved in each parameter.

$$Reserve\ (MW_e) = \frac{Stored\ heat \times Recovery\ factor \times Conversion\ efficiency}{Plant\ load \times Load\ factor} \qquad (1)$$

Uncertainty distributions

Figure 30 illustrates the four most commonly applied uncertainty distributions. A constant or uniform uncertainty distribution is used when a constant is possible over a certain range of values and when any value within definable limit is considered equally likely. The triangular distribution is used when the best guess value for a parameter (most likely modal value) can be specified along high and low extremes. A normal uncertainty distribution is used when the high and the low values are of equal sides and are considered a better representation of many natural resources if a standard deviation can be computed. Log-normal distribution is also common and usually fits a series of measurements like porosity and permeability. Sizes of pebbles on beaches, sizes of petroleum reservoirs as they occur from geologic provinces have been observed to follow this distribution (McCray, 1975)

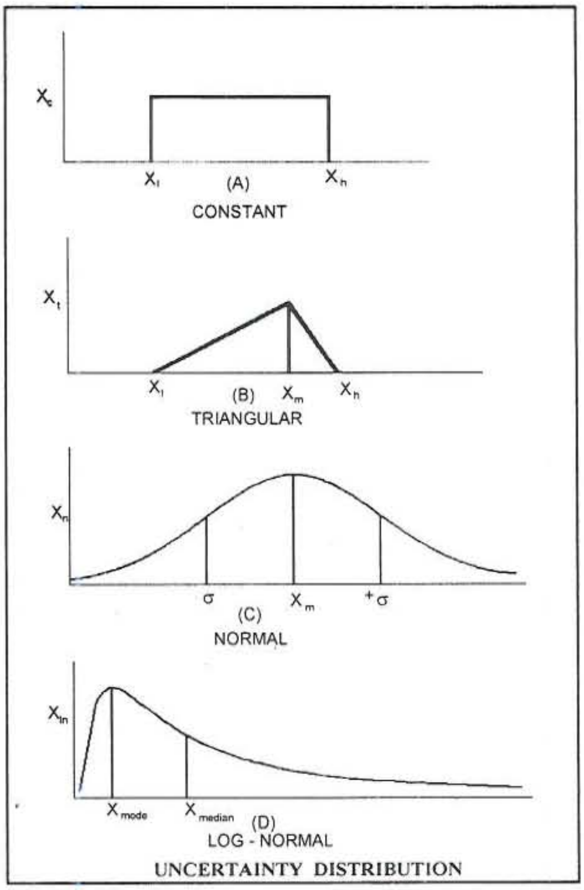


FIGURE 30: Different uncertainty distribution models used in Monte Carlo reserve estimation

Tables 12A, B, C and D illustrate the assignment of the uncertainty distribution model for the different parameters used as input in the Monte Carlo analysis applied in the estimation of potential reserve in the four blocks or sub-areas of the Malitbog sector.

Figure 31 illustrates the combined result of all four Malitbog blocks with a frequency distribution histogram. The histogram indicates a broad range of probability estimates for Malitbog; from 150 to 180 MW_e with the most common value (mode) of 170 MW_e. The cumulative frequency curve shown in Figure 32 indicates that the most likely value of the reserve (median), 50% point of the solution distribution, is 162 MW_e and that there is less than 10% chance of the reserve being less than 130 MW_e, or more than 200 MW_e. Clearly the results indicate that there is little risk in PNOC-EDC's installation of a 110 MW_e and that 165 MW_e is feasible.

Table 13 shows the various parameters used in the stored heat calculation using two sets of input on the porosity and recovery factor. These two parameters are considered to have significant effect on the resulting values as these values cover a wider range; 5 to 15% for porosity and 15 to 38% for the recovery factor. The results indicate that the Malitbog reserve could range from 143 to 196 MW_e. These values are within the range of those estimated from the Monte Carlo simulation because inputs on the best guess estimates in the Monte Carlo analysis are very close to the ones used in this method. However, the advantage of the Monte Carlo analysis is that it clearly illustrates a quantitative representation of the uncertainties involved that are required in the decision making. It tells management and financing institution that there is very little chance of the project not producing 110 MW_e and that producing the field at higher capacity is very feasible.

TABLE 12: Monte Carlo analysis of Malitbog sector of the Tongonan geothermal field, best guess values and probability distribution input

A: Block 1

Parameter	Best guess (model)	Probability distribution Type	Min.	Max.	Standard deviation
Area (km^2)	2.95	Triangular	2.5	3.8	---
Reservoir thickness (m)	2500	Triangular	2000	3000	---
Rock density (kg/m^3)	2670	Constant	2536	2803	---
Porosity	0.10	Log normal	---	---	0.12 (median)
Recovery factor	0.26	Triangular	0.17	0.35	---
Rock specific heat (kJ/kg°C)	.9	Constant	0.85	0.95	---
Av. reservoir temperature (°C)	250	Normal	---	---	10
Fluid density (kg/m^3)	799	Table, f(t)	---	---	---
Fluid specific heat (kJ/kg°C)	4.8	Constant	---	---	---
Conversion efficiency	.13	Triangular	-0.01	+.02	---
Plant life (years)	25	Triangular	20	30	---
Load factor	.9	Triangular	0.8	1.0	---
Abandonment temperature (°C)	180	Constant	---	---	---

B: Block 2

Parameter	Best guess (model)	Probability distribution Type	Min.	Max.	Standard deviation
Area (km^2)	1.7	Triangular	1.4	2.2	---
Reservoir thickness (m)	2800	Triangular	2200	3360	---
Rock density (kg/m^3)	2670	Constant	2536	2803	---
Porosity	0.01	Log normal	---	---	0.12 (median)
Recovery factor	0.26	Triangular	0.18	0.35	---
Rock specific heat (kJ/kg°C)	.9	Constant	0.85	0.95	---
Av. reservoir temperature (°C)	240	Normal	---	---	10
Fluid density (kg/m^3)	814	Table, f(t)	---	---	---
Fluid specific heat (kJ/kg°C)	4.8	Constant	---	---	---
Conversion efficiency	.12	Triangular	-0.01	+.02	---
Plant life (years)	25	Triangular	20	30	---
Load factor	.9	Triangular	0.8	1.0	---
Abandonment temperature (°C)	180	Constant	---	---	---

C: Block 3

Parameter	Best guess (model)	Probability distribution Type	Min.	Max.	Standard deviation
Area (km^2)	1.4	Triangular	1.2	1.4	---
Reservoir thickness (m)	2800	Triangular	2240	3360	---
Rock density (kg/m^3)	2670	Constant	2536	2803	---
Porosity	0.10	Log normal	---	---	0.12 (median)
Recovery factor	0.26	Triangular	0.18	0.35	---
Rock specific heat (kJ/kg°C)	.9	Constant	0.85	0.95	---
Av. reservoir temperature (°C)	260	Normal	---	---	10
Fluid density (kg/m^3)	784	Table, f(t)	---	---	---
Fluid specific heat (kJ/kg°C)	4.8	Constant	---	---	---
Conversion efficiency	.13	Triangular	-0.01	+.02	---
Plant life (years)	25	Triangular	20	30	---
Load factor	.9	Triangular	0.8	1.0	---
Abandonment temperature (°C)	180	Constant	---	---	---

TABLE 12: Continued

D: Block 4

Parameter	Best guess (model)	Probability distribution Type	Min.	Max.	Standard deviation
Area (km^2)	1.5	Triangular	1.3	1.9	---
Reservoir thickness (m)	2200	Triangular	1760	2640	---
Rock density (kg/m^3)	2670	Constant	2536	2803	---
Porosity	0.08	Log normal	---	---	0.12 (median)
Recovery factor	0.26	Triangular	0.18	0.35	---
Rock specific heat (kJ/kg°C)	.9	Constant	0.85	0.95	---
Av. reservoir temperature (°C)	240	Normal	---	---	10
Fluid density (kg/m^3)	814	Table, f(t)	---	---	---
Fluid specific heat (kJ/kg°C)	4.8	Constant	---	---	---
Conversion efficiency	.12	Triangular	-0.01	+.02	---
Plant life (years)	25	Triangular	20	30	---
Load factor	.9	Triangular	0.8	1.0	---
Abandonment temperature (°C)	180	Constant	---	---	---

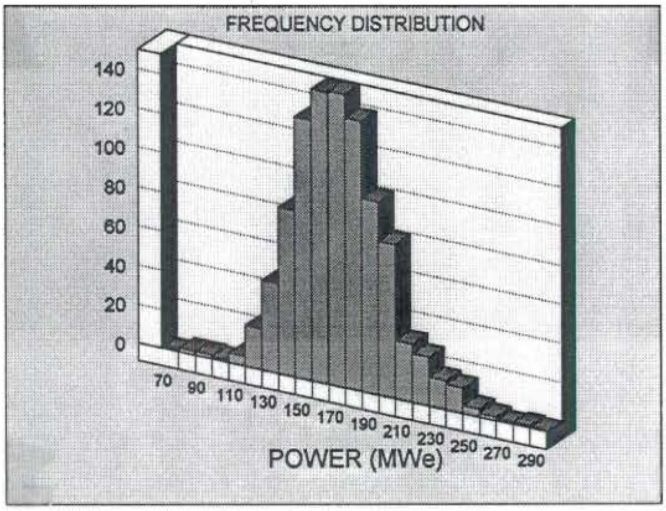


FIGURE 31: Malitbog, frequency distribution of the reserve estimate

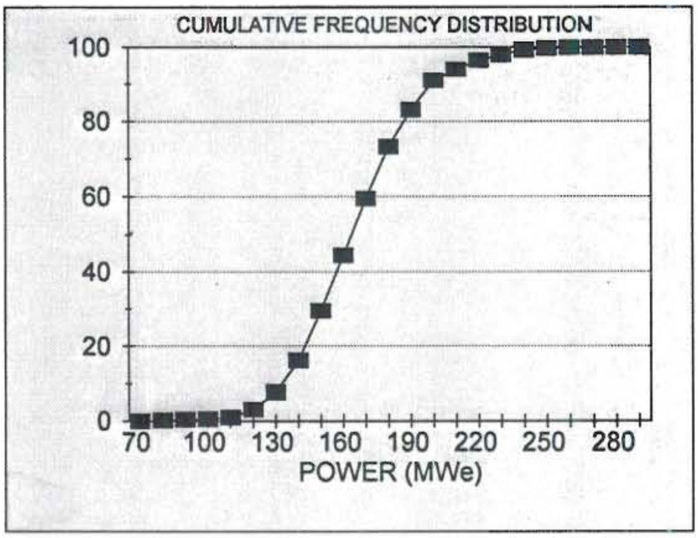


FIGURE 32: Malitbog, reserve cumulative frequency distribution

TABLE 13: Various parameters used in the stored heat calculation for the Malitbog sector of the Tongonan geothermal field (two sets of porosity and recovery factors)

Block	Area (km^2)	Thickness (m)	T_r (°C)	S.H. (kJ/m^3)	Porosity (%)	R.F. (%)	C.E. (%)	Power (MW_e)
ML1	2.95	2,500	250	$1.8x10^5$	10	25	11.5	60.5
ML2	1.7	2,800	240	$1.54x10^5$	10	25	11.0	31.9
ML3	1.4	2,800	260	$2.05x10^5$	10	25	12.0	38.2
ML4	1.5	2,200	260	$1.5x10^5$	5	15	11.0	12.9
Total								143.5
ML1				$1.9x10^5$	15	38	11.5	95.0
ML2				$1.62x10^5$	15	38	11.0	50.0
ML3				$2.05x10^5$	10	25	12.0	38.2
ML4				$1.5x10^5$	5	15	11.0	12.9
Total								196.1

2.6 Lumped parameter modelling reservoir simulation

Reservoir simulation is the most useful reservoir evaluation tool especially in geothermal field where a production history exists. Fields like Tongonan and Palinpinon, have accumulated 10 years of production response that have been used in calibrating the natural state condition and in forecasting future performance. Aquino et al. (1990) and Amistoso et al. (1990) represent the state-of-the-art of numerical simulation works in the Philippines. Their work has been done in collaboration with scientists from Lawrence Berkeley Laboratory, California (LBL) using MULKOM (Pruess, 1982). In Amistoso et al. (1990), another constraint associated with the matching of the chemical distribution and changes on the geochemical response was added in simulating the Palinpinon field and thus improving the confidence on the results of the simulation. This approach was made possible through the transport modelling of a second component, i.e. non-condensable gases and dissolved solid, that can now be handled by MULKOM. The inclusion of a coupled transport of a chemical component provides additional constraint on the numerical model that enables satisfaction of both the physical and chemical match between simulated and actual field data when adjusting main reservoir parameters during the model calibration.

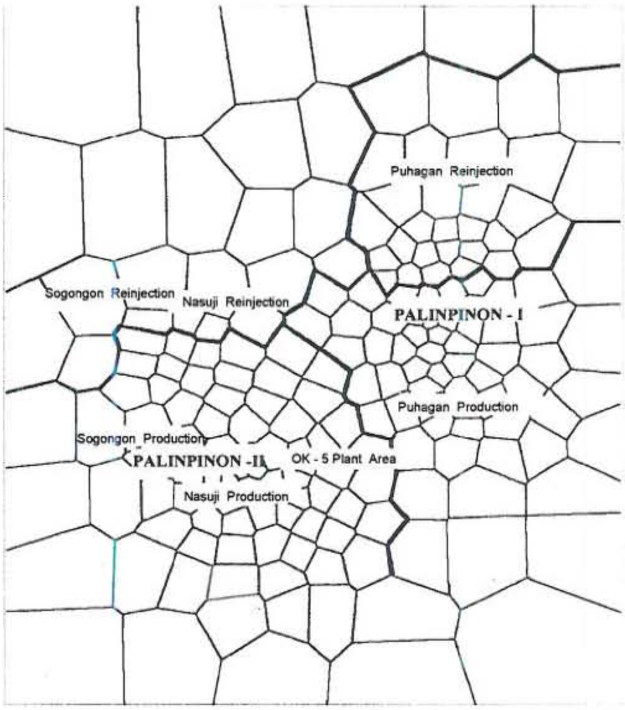


FIGURE 33: The Palinpinon reservoir grid model used in the reservoir simulation

The numerical modelling for Tongonan by Aquino et al. (1990) has been the product of continuous updating in the simulation that began through Aunzo (1986). Their work has been used as the bases for the various developments and reservoir management strategies adopted in the Tongonan field. The results of their work were also used as bases for expanding the currently installed capacity of 112.5 MW_e in Tongonan I through the development of the Upper Mahiao and Malitbog sectors with additional 370 MW_e (Sarmiento et al., 1992).

Figure 33 is the numerical grid used by Amistoso et al. (1990) in simulating the natural state and

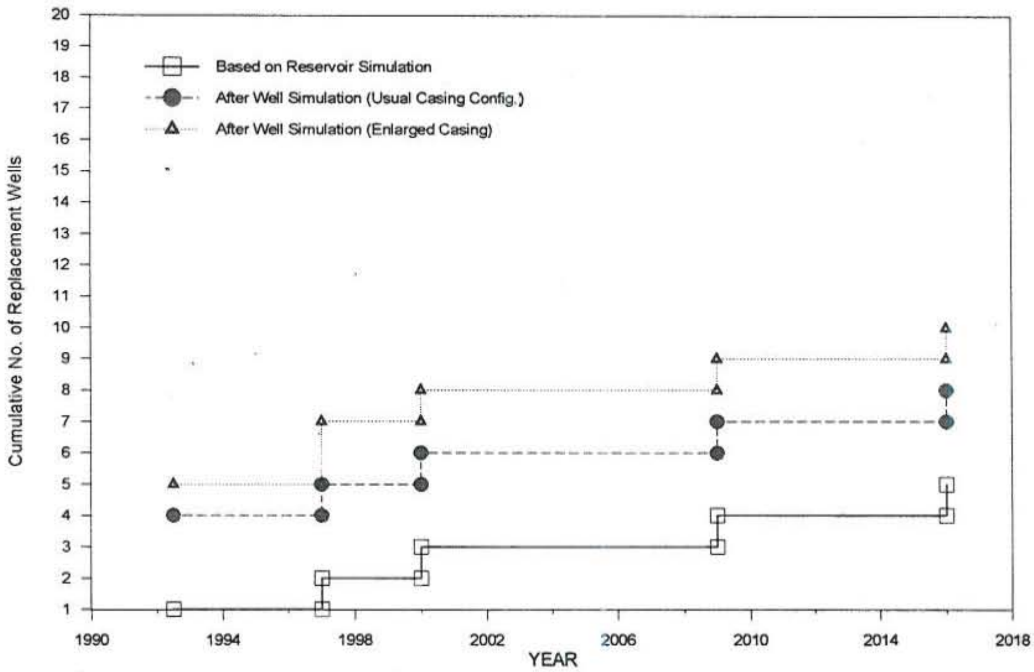


FIGURE 34: Schedule of make-up and replacement well drilling for Sogongon, Palinpinon field

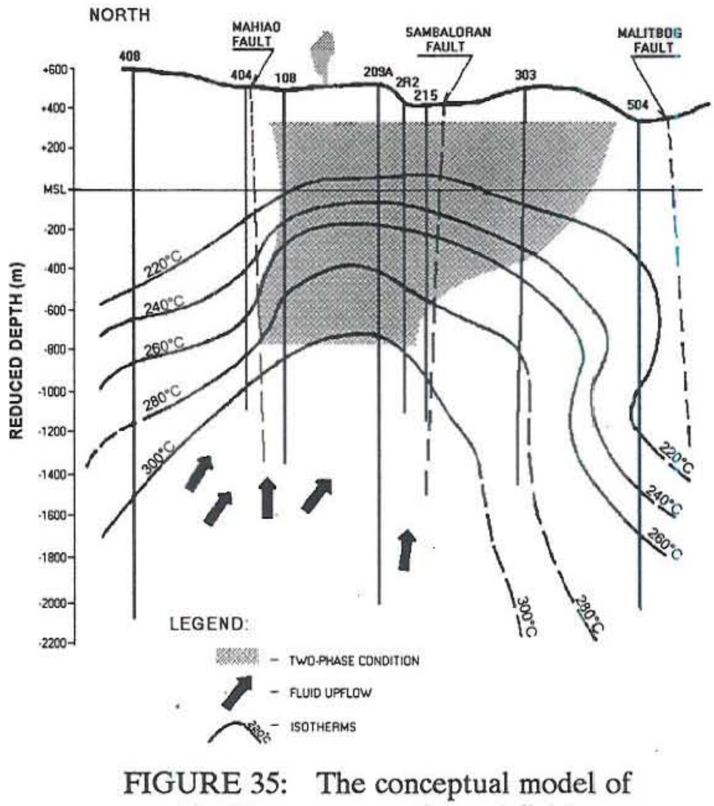


FIGURE 35: The conceptual model of the Tongonan geothermal field

performance forecast of the Palinpinon field. The simulation results indicate that make-up and replacement (M&R) wells have to be drilled to sustain plant capacity for 25 years. Figure 34 shows the well make-up drilling schedule based on various production scenarios. The results also support the development expansion of Palinpinon with an additional 80 MW for 25 years with reasonable number of M&R wells.

Figure 35 shows the conceptual model of the Tongonan field that was used as the basis for modelling its natural state condition, exploitation history and future performance. The model used 405 grid blocks that are distributed in 3 layers. On the basis of the simulation results, several performance forecasts were made that were used in formulating development strategies and committing additional capacities on top of the existing 112.5 MW_e in the field. Figure 36 shows the field performance at 330 MW_e generation assuming open and closed boundary conditions with and without reinjection. The results indicate that brine reinjection

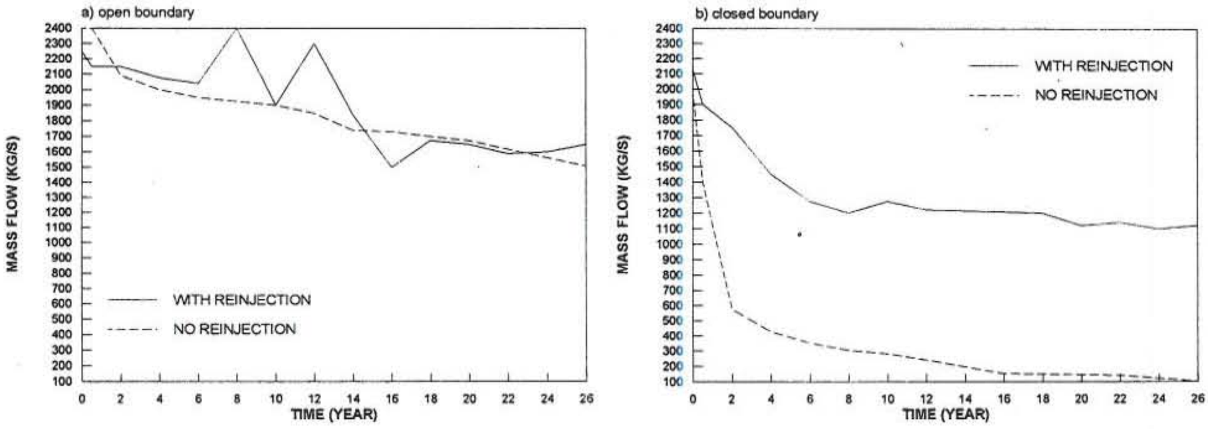


FIGURE 36: Simulated performance prediction of the Tongonan geothermal field in two production scenarios

for Tongonan would be a critical component of its development strategy to maintain production in the long term, especially if the periphery of the field is confirmed to be a close boundary in the future.

2.7 Conclusions

With all these techniques in resource assessment and evaluation, PNOC-EDC was able to confirm more than 1000 MW_e in its present geothermal reserves. Future expansions would then be determined by how these fields would behave in the future. PNOC-EDC would most likely adopt new technologies that might evolve and that would increase confidence in its resource assessment.

3. STRATEGIES IN THE DEVELOPMENT AND MANAGEMENT OF GEOTHERMAL RESOURCES IN THE PHILIPPINES

3.1 Introduction

After a decade of managing Tongonan and Palinpinon fields, PNOC-EDC has acquired considerable operating experience that has been used in formulating suitable development and management strategies in Philippine geothermal fields. Each geothermal field has its own unique development and management strategies, but most of these were patterned on the experience from these two fields. Strategies are assiduously modified during the production stage to suit field behaviour and optimize production. In the current scenario, modification of current strategies and adoption of previously low priority options become inevitable because of strict implementation of environmental rules and regulations.

3.2 Resource development strategies

The confirmation on the existence of a geothermal resource leads the development programme in an area to finally commit a certain block of power for generation. In an ideal case, one should commit the field only after completion of field-wide testing and evaluation to ensure that any development strategies to be adopted fit well with the anticipated behaviour of the field. However, since it would require long duration before the actual characteristics of the field become known and used in the strategy formulation, PNOC-EDC adopts a flexible position as to adherence on resource development and management strategies. Reserve capacity, well characteristics and conceptual model, terrain and the overall project and economic cost to put the field into operation usually guide the selection of field development strategy.

Reinjection philosophy
With the lessons gained from Tongonan and Palinpinon, PNOC-EDC identifies brine reinjection as a critical component of every field development. Until the implementation of the zero waste disposal in the early 90's, reinjection strategies in the Philippines are usually based on the following philosophies:

- Dispersal of reinjection fluids - Geothermal brines should be reinjected into the various parts of the field to avoid concentration of reinjection fluids and their possible returns into a particular production sector. Dispersing the fluids also extends the area of contact between the reinjection fluids and the rock that is required in reheating the fluids before returning into the production sector.

- Deep reinjection - The brine should be reinjected deeper into the field where the temperatures are higher to improve thermal recovery and minimize return of the cooler fluids at shallow depth in the reservoir. This scheme is strictly followed, particularly when the reinjection wells are sited within the production field.

- Peripheral injection - The deleterious effects of reinjection returns into the production wells in Palinpinon have compelled PNOC-EDC to locate most of its reinjection wells at the edges and, if possible, outside the proven boundaries of the field. Bacman I adopted this strategy by siting most of the reinjection wells 2-3 km off the production field (Figure 7). However, this can be constrained by the lack of permeability at the field boundary as observed in Tongonan I, where drilling of two reinjection wells (1R6D and 1R7D) indicate lack of permeability because of mineral deposition along fractures in the formation.

- Gravity Reinjection/Injection Pumping - A close and/or open system gravity reinjection is preferred requiring locations of reinjection pads at lower elevation than production pads. This scheme significantly brings down the cost of the fluid collection and disposal system. However, in areas where the selected reinjection wells have higher elevations than the separator pads, then injection pumping will be adopted

Recently, there has been a drastic change in the company's reinjection philosophy. The zero waste disposal scheme imposed by the government regulating body restricts development of many areas particularly when (a) the existing terrain is tough, (b) permeability on the edges of the field is tight, (c) faults control the major permeability resulting to rapid communication between production and reinjection wells, (d) the water fraction on the discharge is very high and (e) when gravity reinjection is not possible. The recent decision to utilize geothermal brine for binary power generation and having to inject the plant's waste (utilized brine) at considerably low temperatures of 134°C further imposed restrictions towards adherence to the original reinjection philosophy.

- Cold Injection - The above constraints compelled PNOC-EDC to consider cold effluent injection into its current field development and management strategies. With cold effluent injection, the cost of fluid handling and pipework is minimal; the problem on silica deposition in the line and the reinjection wells are minimized; and wells that are not previously utilized because of their distance from the production and reinjection sectors can now be hooked up for injection. However, reservoir management would have to deal with the effects of relatively cold fluids on their return to the production sector, e.g., by locating the injection wells farther away than previously targeted.

Solis et al. (1991) describe the results of the low temperature injection experiments in Bacman that became the basis of its first adoption in testing the production wells in the Bacman II area. The results of that experiment indicate that silica deposition associated with the injection of low temperature brine can be avoided with the use of cascading ponds to age the brine and maintain a silica saturation index (SI) of 1.0 before injecting to the reinjection wells.

Figure 37 shows a schematic diagram of the cold water injection scheme designed for implementation in Bacman II 2x20 MW_e modular plant and in all other fields under development. This scheme also includes disposal through injection of steam condensates from the power plant. In some instances, these condensates will be mixed with the hot geothermal brine and or the two phase fluids upstream of the separator to be used as dilutant in reducing the silica saturation index that has been increasing with time due to increasing enthalpies and continuous reinjection returns to the production wells (Figure 38).

3.3 Production philosophy

The main production strategy in developing a field focuses on maintenance and sustenance of the field capacity during exploitation. This strategy is usually the option where the project cost and field capacity are optimized. Over-exploitation is avoided because all economic considerations on the field development are based on the 25 year lifespan of the power plant.

The following parameters have considerably affected the choice of production strategy in the Philippine geothermal setting:

Well flowing pressures
The basis of process design followed in the construction of the steamfield fluid collection and disposal system and the power plant has been the result of the wells' discharge performance during the testing period. This means that the design of the fluid collection and disposal system and the power plant interface data depend on the overall field capability. In the construction of Tongonan I and Palinpinon I, over-conservatism was imposed in both the fluid collection and disposal system and power plant operating condition because of uncertainties on how the field will behave. A turbine inlet pressure of 0.5 MPaa was decided for both plants even though the wells in Tongonan I can sustain pressures higher than 1 MPaa. The concern on possible reservoir pressure drop in the future constrained

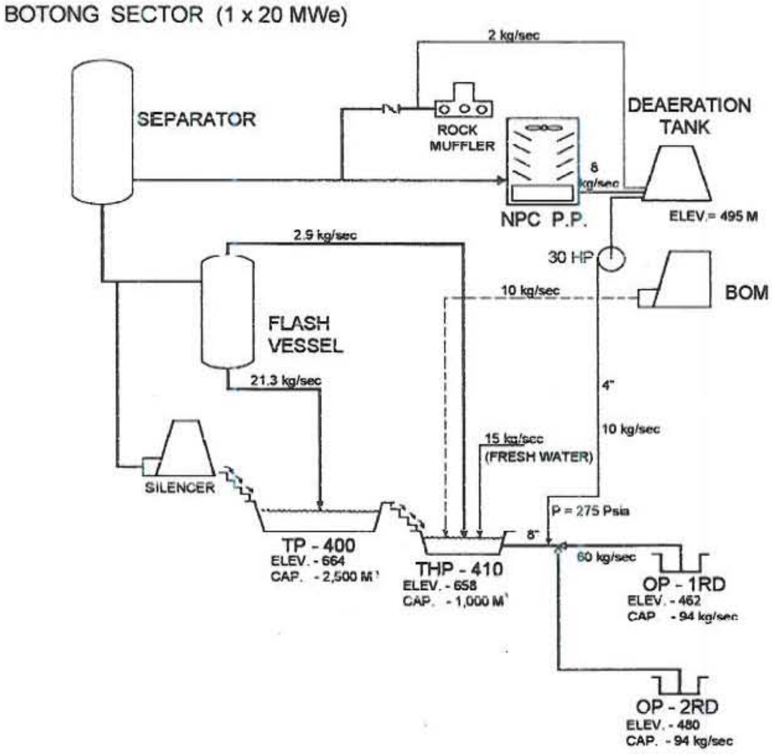


FIGURE 37: Schematic diagram of the cold injection scheme for Bacman II production field

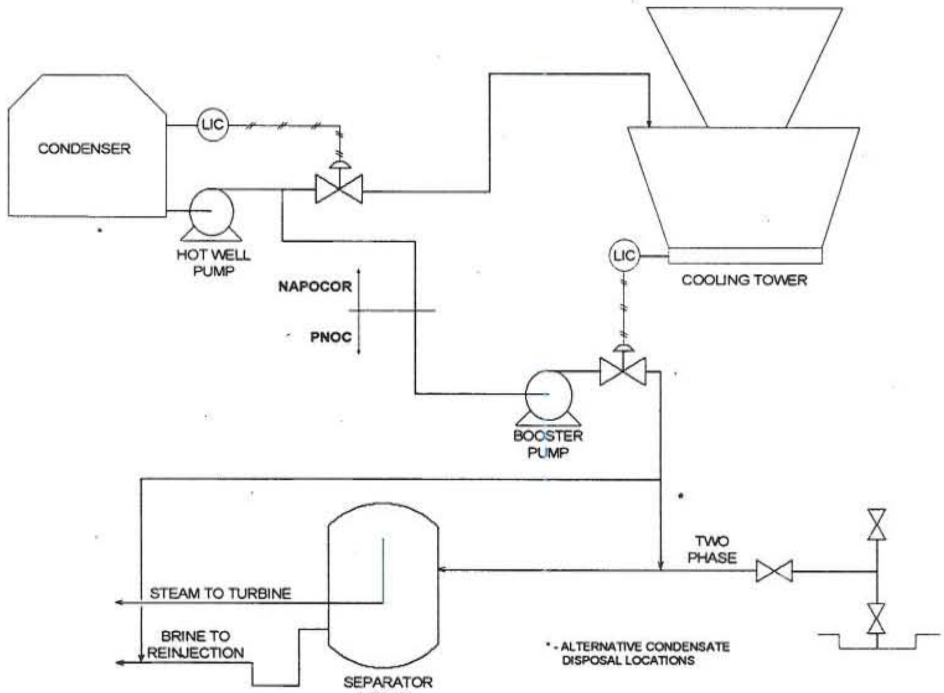


FIGURE 38: An alternative steam condensate disposal scheme

the designers to adopt the low pressure for fear that the plant can't be operated in case of field rundown. Figure 39 shows the Tongonan overall output curve against operating wellhead pressure. The optimum pressure lies at 1.5 MPaa and could have been the turbine inlet pressure for the existing 3x37.5 MW_e units.

Recently, Sarmiento et al. (1992) reported that Tongonan I could have been operated at higher pressures. It has been recommended that the proposed plants for Upper Mahiao and Malitbog sectors be designed at high pressures to take advantage of higher turbine and thermodynamic efficiencies. This recommendation has been based on the performance of the Tongonan I wells after 13 years of operation and the results of the wellbore and reservoir simulation for the entire field.

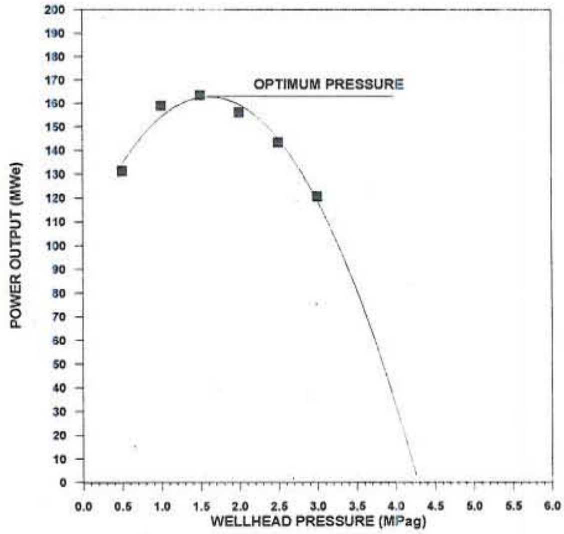


FIGURE 39: The total field output curve of Tongonan I, showing optimum pressure

Casing configuration
Until very recently, well casing design in the Philippine constitutes only the conventional 9⅝" as production casing and 13⅜" as anchor casing. With the availability of GWELL wellbore simulator (Aunzo, 1990), we had established a comparison of the benefits and the cost of drilling large and conventional holes. The break-even point where a big hole looses its advantage is if the hole can only gain a 30% increase in power. On the other hand, wellbore simulation results indicate that as high as 60 to 80% increase in power can be obtained in areas where the wells' output are wellbore controlled - i.e. the output is controlled by the wellbore size. With known production performance on initial wells in a field, additional wells can be drilled with large diameter casing when necessary. Figure 40 shows the comparative calculated output of well OK-6 in Palinpinon and well 212 in Tongonan at 9⅝" and 13⅜" casings.

Field enthalpy
The average field enthalpy dictates the number of reinjection wells and size of reinjection systems to put up in an area. High enthalpy wells produce relatively smaller amounts of effluent than those low enthalpy wells. For example, in Mt. Apo, the first 3 production wells were drilled near the outflow of the field and thus producing low enthalpy fluids. Although the sector can produce the required capacity of 40 MW for the first unit, the drilling programme has to be shifted towards the upflow region to obtain better well output, reduce the required number of wells and meet the programmed commissioning of the plant by September 1994. Figure 13 shows the location of the well targets for the first 40 MW Mindanao I plant.

On the other hand, the current strategy in the management of Tongonan I and Palinpinon I is to drill additional wells within the steam cap to minimize the amount of wastewater being produced in the field to reduce the effects of reinjection returns to the production wells.

Fluid chemistry
Cut-off pH from the discharge fluid from the production wells is set at 4.5 during which corrosion effects are monitored. Once the pH of the discharge fluids becomes lower than the cut-off value, the well is cut out of the system and more often becomes non-commercial. More recently,

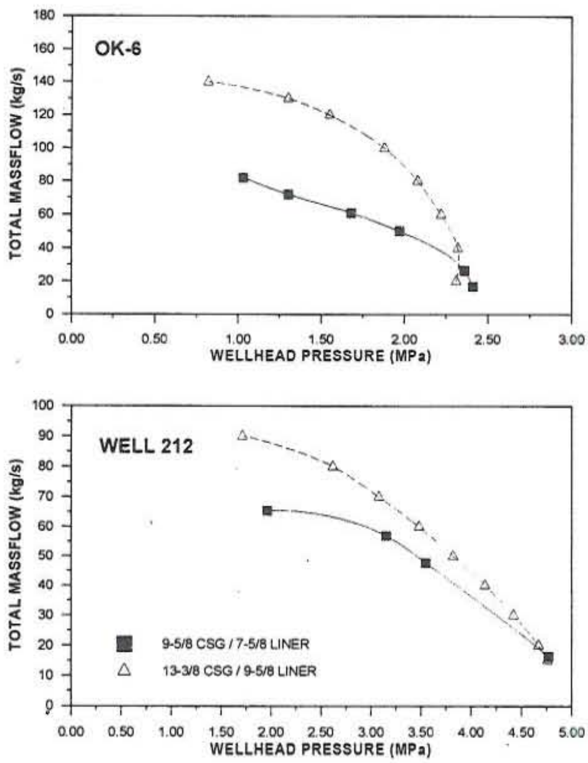


FIGURE 40: Comparison of wells' output at two casing size configurations

however, it was shown in Palinpinon I, that by inducing reinjection returns into the acidic feeds of these wells (OK-10D and PN-22D), the pH of the overall discharge improves, and the well becomes reusable for commercial production.

Reservoir fluids in the Philippines are highly mineralized as temperatures in most geothermal fields are over 300°C. After the separators, these minerals reached supersaturation in the brine after flashing at low pressures, i.e. at 0.6 MPaa. Whenever possible, PNOC-EDC optimizes the separation pressure concerning silica saturation to mitigate scaling. In Bacman I, the wells will be initially operated at 1.0 to 1.2 MPa, even though the turbine inlet pressure is only 0.5 MPa, to maintain a silica saturation index (SI) close to 1.0.

Topography

When a geothermal resource is located in a mountainous terrain, as in the case of Palinpinon, Mahanagdong, Alto Peak, Bacman and other areas, roadworks and pad constructions are usually limited, and are dictated by the terrain of the area. Production wells are usually lumped in a few number of pads, and are drilled directionally to be able to tap the inferred upflow or resource. Fluid collection and disposal systems of such development tend to become less complicated, however, as the wells can easily be connected to the steam gathering system since their wellhead will be close to each other. Figure 10 shows a typical compact development scheme for the Palinpinon field.

Gravity reinjection also becomes more feasible as the reinjection wells are usually situated in the outflow, and usually at lower elevation than the production sector. However, when there are constraints on permeability at lower elevation and the only option is to inject into elevated pads, then reinjection by pumping is resorted.

3.4 Resource management strategies

Reservoir management is essentially overseeing the operations of the geothermal field aimed at ensuring the sustainability of plant operation for 25 years or longer. It is basically reservoir monitoring where changes in the reservoir characteristics are tracked, evaluated and potential problems are identified so that appropriate measures can be made. Stefansson (1986) cited three conditions whereby successful reservoir management can be carried out:

- Knowledge on the geothermal system, size, internal properties and mechanism of the geothermal system; otherwise expressed as the conceptual model of the field.

- Knowledge on the dynamic behaviour (response) of the geothermal system including pressure-drawdown, fluid phase transition caused by exploitation, and effect of recharge to the system.

- Up-to-date evaluation of the system - monitoring.

The conceptual model of the field is usually established before the field is committed for operation but has to be updated when necessary once new observations become available. Before the response of the field is known during the operation of the plant, close monitoring of the wells' production characteristics should be done. Table 14 shows the various parameters prioritized by PNOC-EDC in their monitoring of operating fields.

TABLE 14: Reservoir parameters monitored by PNOC-EDC to manage the geothermal fields (after Salera, 1991)

Production wells
• output: massflows, enthalpies, wellhead pressures
• downhole temperatures and pressures
• downhole blockages/obstructions: scraper samples
• fluid chemistry
Reinjection wells
• reinjection capacity, pressures
• downhole temperatures, pressures
• downhole blockages/obstructions: scraper samples
Reinjection lines
• fluid chemistry: SiO_2
• scales samples
Steam header
• fluid chemistry: CO_2, H_2S, Na
Monitor/Observation wells
• downhole temperatures and pressures, wellhead pressures
• downhole blockages/obstructions: scraper samples
Field microseismicity
Field thermal manifestations, hot springs

Field output monitoring
In the case of Palinpinon where 22 wells are supplying steam to the power plant, individual monitoring of wells will be difficult to do especially at regular intervals. Initially, wells that are significantly affected by reinjection returns and pressure drawdown are prioritized for testing - at least every 3 months. The total output of the field is then deduced from the sum of previous outputs of wells not tested at the time of estimation plus the output of those wells recently tested. Here, the probability of not obtaining an accurate field output estimate is high because wells' output are changing with time, especially those with known response from reinjection returns. However, this method has been accepted and found to be reliable in predicting the needs for changing well prioritization schedule, work-over and drilling additional wells for injection and production.

Lately, as the load increased to near plant capacity, field output capacity measured through the power plant meter became possible. Here, the turbine performance at inlet pressures is known as well as at various vacuum conditions. The latter is quite critical because condenser vacuum levels vary in the plant from time to time, depending on several factors. When all the wells are on line, the total output of the field is measured, with certain amount of steam allotted for the steam gas ejectors and steamfield blow-off. There is no steam orifice installed in the plant, hence, this indirect measurement.

Figure 41 shows the comparison of Palinpinon field capacity based on power plant estimate and that from bore output measurement using James' method. Through this technique, even the wells which are cycling at the time of measurement and while supplying to the power plant were identified like wells PN-17D and PN-14D. The results become more applicable in projecting steam shortfall although it does not answer changes on individual well output.

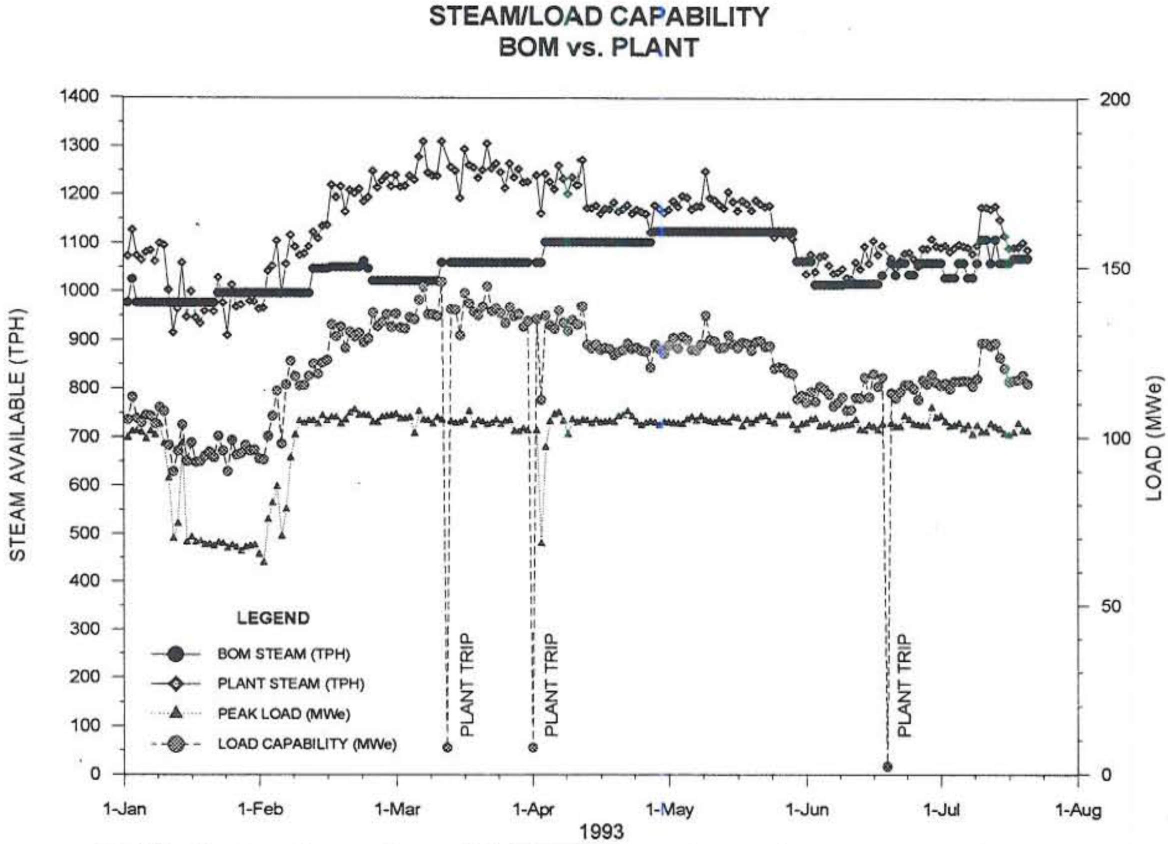


FIGURE 41: Comparison of field capacity estimates based on James' method and station plant metering

Reinjection flow and capacity monitoring

Total reinjection flow and reinjection well capacity measurements are essential in good reservoir management, especially in a field where there is continuous return of reinjection fluids to the production sector. Estimates of the total wastewater flow gives indication on whether the field enthalpy is increasing or declining and therefore the pattern on the behaviour of the production wells. On the other hand, estimates on the changes in the reinjection wells capacities indicate whether a work-over is necessary to recover lost capacity or drill additional well to cope with the reinjection load requirement. However, due to the nature of the steamfield operations, known methods of measuring waste waterflow through orifice or flowmeters are not easily doable. Installation of orifice requires cutting off the reinjection line while the use of flowmeters require mobilization of logging trucks. These constraints limit the collection of measurement data that are badly needed in making decisions regarding the management of the resource.

Very recently, PNOC-EDC had devised a more convenient, highly precise chemical method of measuring liquid flowrates along the reinjection lines. The technique requires injecting a conservative, non-reactive chemical tracer (concentrated magnesium chloride) at one point on the reinjection line, then monitoring its arrival at some distance downstream of the same line (Jordan, 1991). From the breakthrough curve of the magnesium tracer shown in Figure 42, the total wastewater flowrates were calculated within 2% mean difference with orifice and silencer methods using simple, mass balance equation:

$$F_1C_1 + F_2C_2 = F_3C_3 \qquad (2)$$

where:

- F_1 = unknown (injection waterflow rate in kg/s)
- C_1 = baseline Mg concentration of the injection line fluid (mg/kg)
- F_2 = dosing flowrate (l/s)
- C_2 = magnesium concentration of the injectate (mg/kg)
- $F_3 = F_1 + F_2$
- C_3 = ave. equilibrium Mg concentration of the samples monitored downstream (mg/kg)

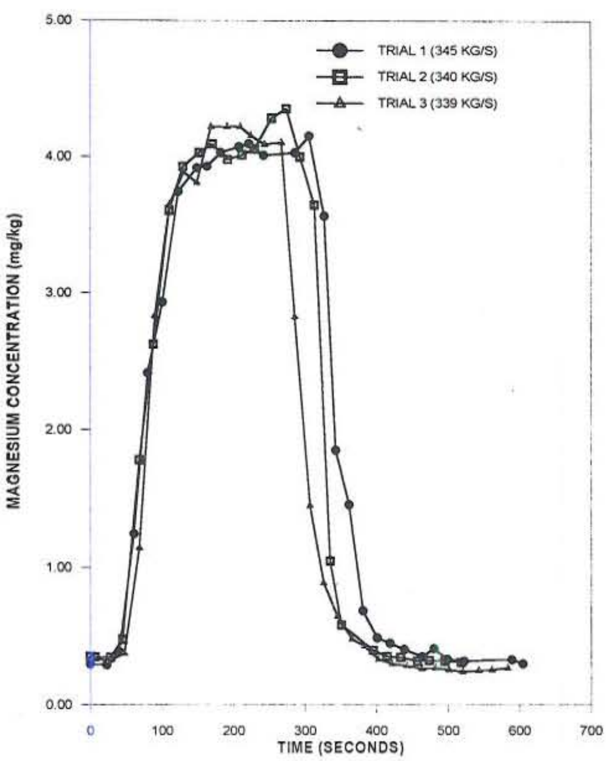


FIGURE 42: Magnesium tracer breakthrough used in estimating waterflows

The equation can thus be simplified as

$$F_1 = \frac{F_2C_2}{C_3 - C_1} \qquad (3)$$

The results of these measurements have enabled up-to-date monitoring of the total wastewater flow as well as capacities of individual reinjection wells both in Palinpinon and Tongonan; providing information on how the field reacts to changes in reinjection well utilization, especially when a particular well or group of wells are utilized at certain periods. Policy decisions on drilling additional production or reinjection wells can be made with greater confidence because of the accuracy and timeliness of the data. Similarly, modification of well utilization schedules and priorities become easy. Table 15 shows a comparative result of the chemical tracer technique and the estimated output using James' lip pressure method.

Figure 43 shows the comparison of the spinner flow measurements and the chemical tracer on the capacity measurements of reinjection wells in Tongonan.

With the success in this technique, trial measurement of the steam flow is now being undertaken using injection of inert gas tracer to the steam line and monitoring its arrival downstream of the line. The same principles and mathematical relation apply as with the Mg chloride tracer technique. It is thus expected that on-line bore output measurement can be done with ease and precision through these two techniques making available critical well data that are otherwise difficult to obtain using conventional methods.

TABLE 15: Comparison of chemical tracer measurements and James' method

Date	Time	Water flow (kg/s)	Steam flow (t/hr)	Dryness (%)	Calc. enthalpy (kJ/kg)	James' enthalpy (kJ/kg)	Diff. (%)
24 June 91	1100	559	1110	35.55	1424	1522	6.4
	1200	558	1105	35.50	1423	1522	6.5
	1400	560	1115	35.61	1426	1522	6.3
	ave	559	1110	35.55	1424	1522	6.4
20 July 91	1100	459	1065	39.21	1500	1525	1.7
	1200	455	1031	38.62	1488	1525	2.5
	1400	446	1035.7	39.2	1500	1525	1.7
	ave	453	1043.9	39.0	1496	1525	1.9
2 Sept. 91	1100	464	1241	42.6	1571	1537	-2.2
	1200	458	1177	41.7	1551	1537	-0.9
	ave	461	1209.3	42.5	1561	537	-1.6
		OK-7 was cut out and PN-27D off-line					
	1400	439	1219	43.6	1590	1549	-2.65
	1500	444	1227	43.4	1588	1549	-2.5
	ave	442	1223	43.4	1589	1549	-2.6
10 Oct. 91	1200	450	1128	41.0	1538	1574	2.3
	1300	440	1148	42.0	1558	1574	1.0
	ave	445	1138	42.5	1548	1574	1.6
		PN-17D was cut in and PN-20D off-line					
	1500	452	1140	41.2	1541	1552	.68
	1600	454	1153	41.4	1545	1552	.47
	ave	453	1146	41.3	1543	1552	.58

Well work-over

Mineral deposition has been occurring in some of the production and reinjection wells in Tongonan, Palinpinon and even Bacman. Anhydrite blockage occurs in wells where there is mixing of SO_4 rich fluids with Ca rich fluids from different feed zones during production. On the other hand, silica scaling is a common problem in reinjection wells because the brine being injected is supersaturated with silica. These phenomena reduce the respective productivity and injectivity of the wells that require remedial action.

In the 80's, PNOC-EDC usually cleared the well by plain mechanical work-over or drill-out of the blockage to restore well productivity and capacity. Positive results have been achieved from this technique as shown in Figure 44. Well 2R4D had initial capacity of 85 kg/s before plant commissioning in 1983. Over the years, silica scales reduced its capacity that required clearing through work-over. In its last work-over, the restored capacity was sustained for only a short period, indicating that scaling had already blocked the formation permeability. After the work-over, the capacity declined rapidly after a month from work-over. Well OK-10D is a production well in Palinpinon which had been affected by anhydrite deposition. The output decline had been attributed to this deposition that also requires work-over. At least 2 work-overs had already been conducted in OK-10D because of continuous recurrence of anhydrite deposition.

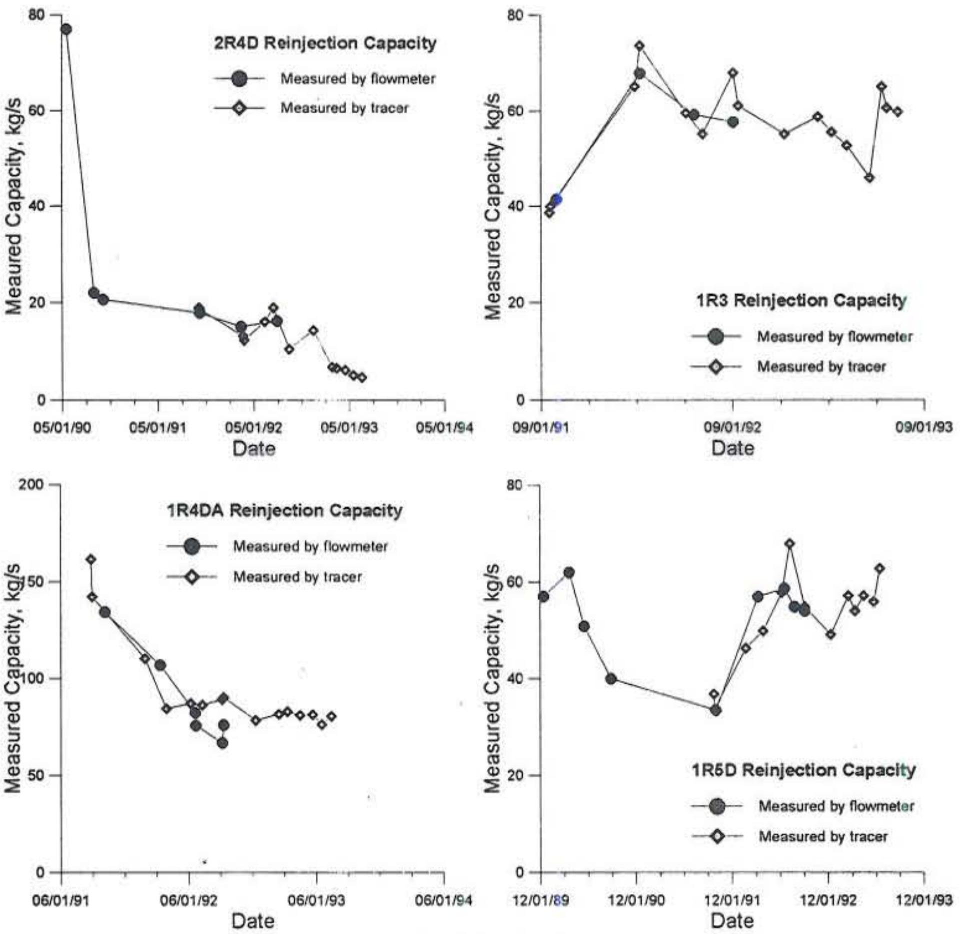


FIGURE 43: Comparison of waterflow measurements using downhole flowmeter and magnesium tracer

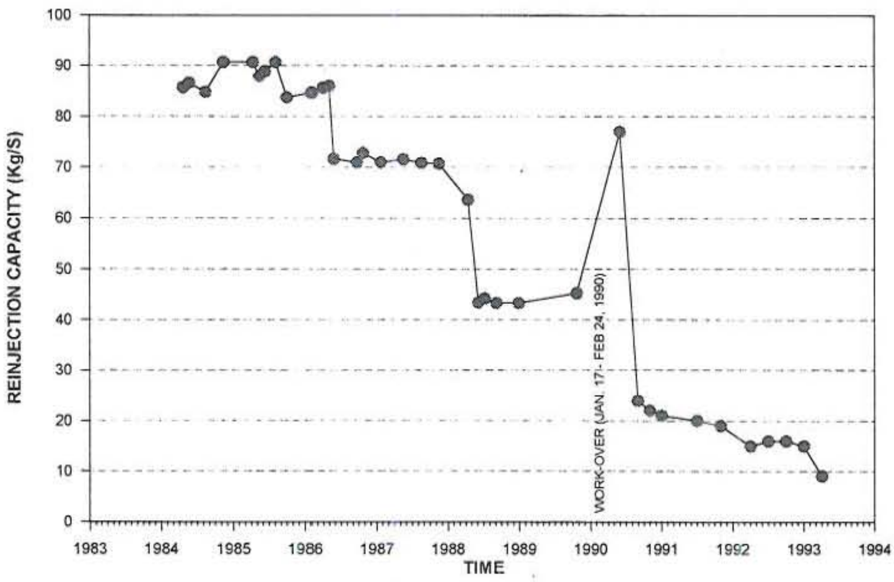


FIGURE 44: Well 2R4D injection capacity with time

Acidizing

The results of the 2R4D work-over indicate that mechanical work-over can only be effective up to a certain extent where mineral deposition has occurred in the borehole. It can not address the damage caused by drilling muds and fluids deep into the formation. Hence, PNOC-EDC programmed two acidizing jobs involving a production well that was damaged during drilling and a reinjection well that suffered a reduction in capacity due to mineral deposition.

The first stage of the programme called for a mechanical work-over to clear any mineral deposition or blockage within the borehole, and the second stage involved actual acid injection slightly above the feed zone. Hydrofluoric acid will react and dissolve nearly any clays and other siliceous materials; and is, therefore, the best acid to treat mud damage and silica deposition. This is made by reacting ammonium bifluoride (ABF) with hydrochloric acid. On the other hand, hydrochloric acid is best suited for treating carbonates in the formation.

The first two wells acidized by PNOC-EDC are PN-32D and PN-2RD in Palinpinon. PN-32D is a production well which was prematurely completed at 2185 m (VD, vertical depth) due to drilling problems. A total of 12,290 barrels of mud was lost in the hole during drilling. A total of 280 sacks of cement was also pumped down the hole to cement and enable sidetracking of the hole at 1580 m. Completion test and heat-up data indicate permeable zones at 1100-1200, 1300-1500 and 1900-2100 m. While the injectivity index appears to be within the average of Palinpinon wells at 18 l/s-MPa, this was not consistent with the indications from drilling losses. The calculated transmissivity index of the well was also found to be very low at 0.5 darcy meter, indicating that the well was damaged. When the well was put on line for production, the well could hardly sustain discharge as it could only flow for 1 or 2 hours to the system. It could not develop wellhead pressure of 0.6 MPa at full bore discharge requiring throttling so that it can be used to the system. The well ultimately delivered 2.2 MW_e after several months of discharge to the system.

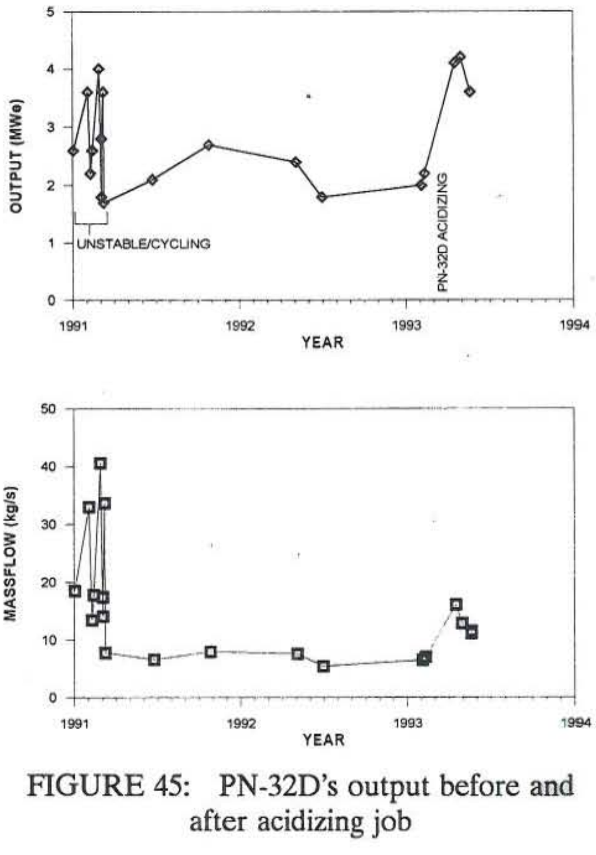


FIGURE 45: PN-32D's output before and after acidizing job

Figure 45 shows the output trend of the well since it started production while Table 16 shows the changes on various well parameters before and after the acidizing completion. The results of the acidizing job caused the well output to increase from 2.2 MW to 4.2 MW corresponding to 100% improvement in capacity. PN-24D, a well that was drilled adjacent to and shares the same fault structures with PN-32D, subsequently increased its capacity also after the acidizing of the former. This well was observed to have manifested significant changes in the magnesium, fluoride and chloride contents of its discharge fluids after 24 hours (Figure 46). It was inferred that this increase in magnesium is caused by the leaching of the rock by acid that had probably reached PN-24D during the acidizing job. Subsequent output monitoring of PN-24D indicates an increase in its capacity from 3 to 5 MW_e. It is also possible that this increase in output could already have happened before acidizing, but lack of measurements then makes the interpretation difficult.

TABLE 16: Well PN-32D, changes on well parameters after the completion of acidizing (Sta Ana, 1993)

Parameters	Before acidizing	Post acidizing	Remarks
Injectivity Index (l/s-MPa)	14.5	22.5	
Output			
Mass flow (kg/s)	7.0	12.8	
Enthalpy (kJ/kg)	2532	2584	
Power potential	2.2	4.2	
Back-pressure plate	A5	FBD	BPP-well is choked; FBD-well is fully open
WHP (MPa)	0.75	0.61	

PN-2RD is a reinjection well that was next acidized to check the effectiveness of acids in dissolving silica scales in the formation or fractured channels. Acidizing of this well was given priority because it is one of the few priority reinjection wells in Palinpinon that do not communicate rapidly with the production sector. The initial capacity of this well was measured to be 60 kg/s. Over the period, its capacity had declined to 40 kg/s requiring the use of non-preferred injection wells to handle the increasing reinjection load from the field. The reduction in its capacity was inferred to be due to silica deposition in the wellbore and the formation as indicated by the silica samples retrieved from the well.

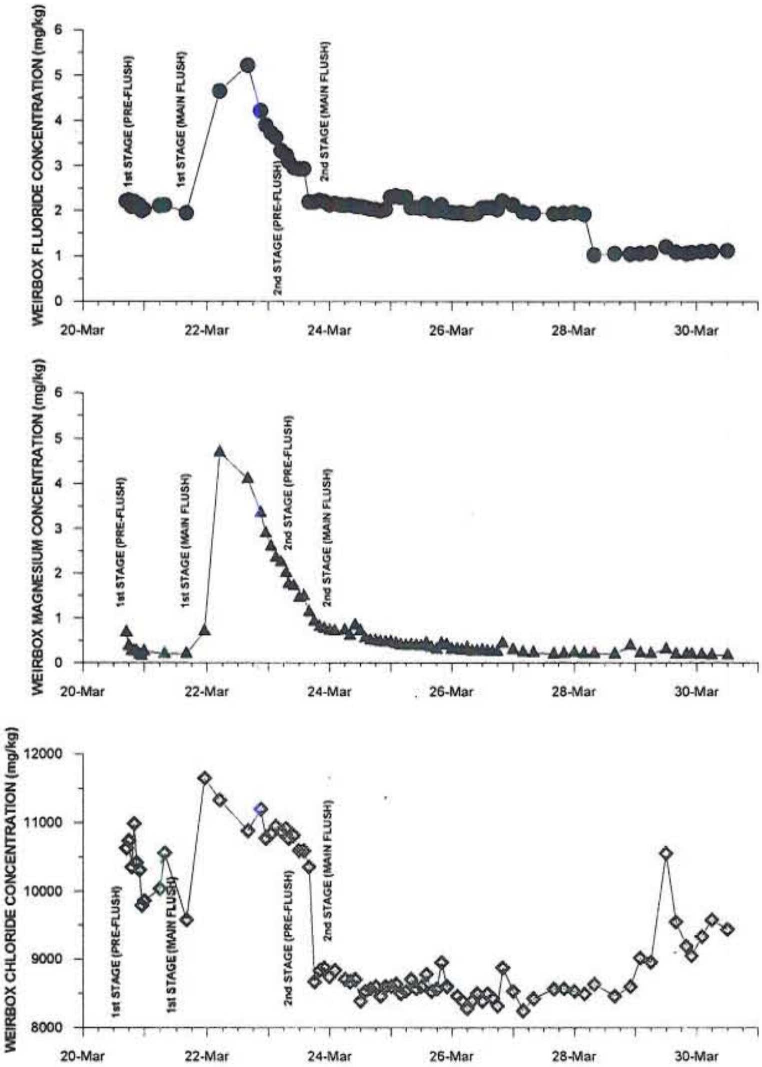


FIGURE 46: Breakthrough curves of acid fluids in well PN-24D during acidizing job at PN-32D

The same procedure as in PN-32D was followed in acidizing the well except that the volume of acids in this well was significantly lower as shown in Table 17. Besides, only the bottom zone was acidized as this was the only zone inferred from the well that was not communicating with the production sector. A total of 33,510 gallons was pumped down the hole opposite the bottom zone.

TABLE 17: Schedule of acidizing jobs for PN-32D and PN-2RD (Sta Ana, 1993)

	PN-32D (top zone)	**PN-2RD (bottom zone)**
Depth of OEDP, m	1150	1900
Pre-flush		
Concentration (%)	10.3, HCl	12.6, HCl
Volume (gallons)	40,204	33,510
Pumprate ratio (bpm/bpm)	8.9:3	6.5:7
Av. pump pressure (MPa)	13.1	18.1
Av. line pressure (MPa)	10.7	17.1
Main flush		
Concentration (%)	9.1, HCl - 4.9 HF	11.9, HCl - 5.5 HF
Volume (gallons)	59,709	51,168
Pump rate ratio (bpm/bpm)	8.7:3	6.8-7
Av. pump pressure (MPa)	13.4	17.7
Av. line pressure (MPa)	11	16.6
Depth of OEDP, m	1900	
Pre-flush		
Concentration (%)	11.9, HCl	
Volume (gallons)	34,375	
Pump rate ratio (bpm/bpm)	7.4:3	
Av. pump pressure (MPa)	13.4	
Av. line pressure (MPa)	11	
Main flush		
Concentration (%)	9.8, HCl - 5.2 HF	
Volume (gallons)	46,503	
Pump rate ratio (bpm/bpm)	7.5:3	
Av. pump pressure (MPa)	13.4	
Av. line pressure (MPa)	11	

Figure 47 shows the injection capacity trend of the well PN-2RD since 1983. Table 18 summarizes the changes in the various well parameters before and after acidizing.

TABLE 18: Changes in parameters of PN-2RD after acidizing (Sta Ana, 1993)

Parameters	Before drill-out	Post drill-out/ Pre acidizing	Post acidizing
Injectivity index (l/s-MPa)	7	65	96
Transmissivity index (Dm)	0.4-0.6	4.4-31	7.6-32
Reinjection capacity	58	340*	393* 187**

* Calculated (max) ** Measured

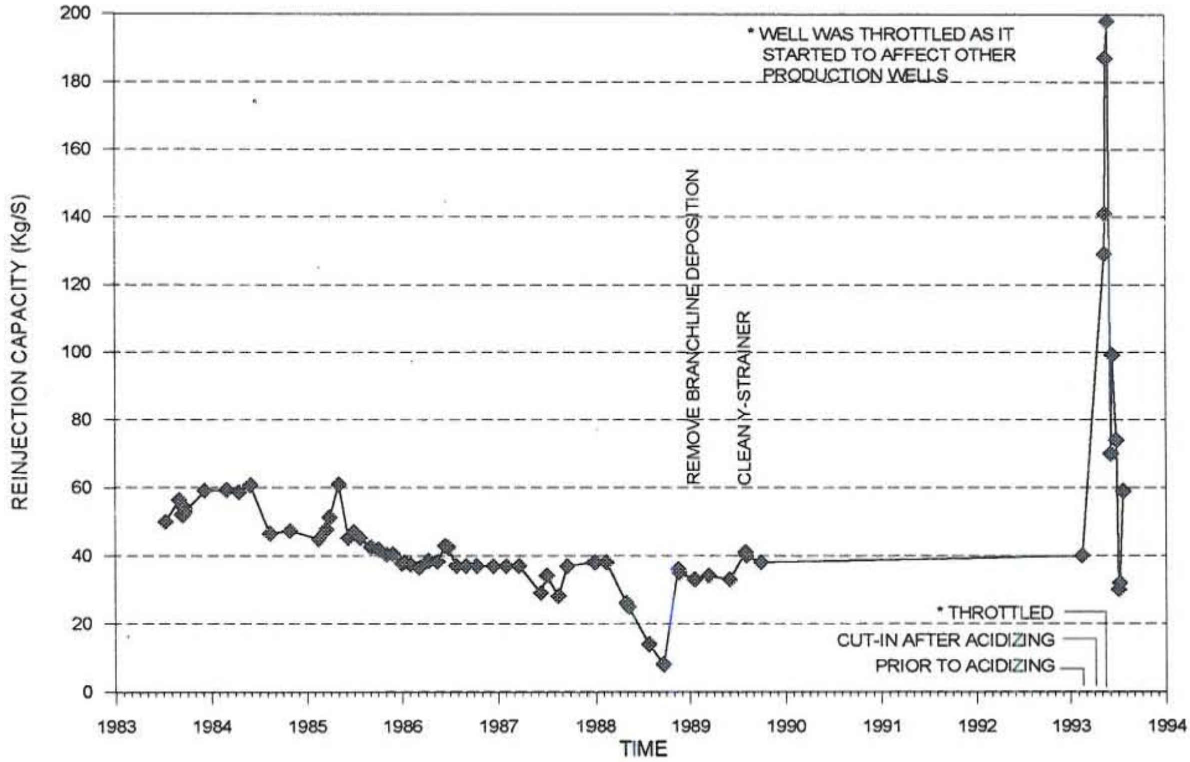


FIGURE 47: The injection capacity of PN-32D before and after acidizing job (1983-1993)

Significant increase in reinjection capacity was estimated based on the injectivity index of the well. Actual measurement taken after the re-commissioning of the well to the system indicates that the well was accepting 187 kg/s at 0.7 MPa injection pressure. This flow is already equivalent to more than 300% improvement over the pre-drill out measurement and 16% above the post drill-out estimate. As a result of this acidizing, the top zone that was not previously accepting fluids became a receptor that currently communicates with the production sector. Well PN-29D exhibited a decline in output from 8.5 MW to 3.5 MW a few days after utilizing PN-2RD to the system. The discharge enthalpy declined from 1300 to 1100 kJ/kg. Chloride levels in some other production wells also increased in response to the utilization of this well. These results prompted the reduction of the injection load to PN-2RD to its previous load of 60 kg/s. As soon as the PN-2RD load was reduced, PN-29D output went back to its original capacity.

Temperature-pressure-spinner (TPS) logging

The temperature-pressure-spinner tool is a composite temperature, pressure and spinner tool that can be run at 300°C in one logging. This tool had been recently used, mainly in Bacman and Palinpinon reinjection wells, for measuring flowrates and determining acceptance of individual feed zones. Table 19 shows the comparison of the estimated and measured injection capacity of Bacman wells. The temperature-pressure-spinner logging was conducted to confirm the theoretical capacity of the well and decides whether additional wells have to be drilled to meet expected reinjection load. The Bacman fluid collection and disposal system then has no provision for orifice measurement during the commissioning period. The results indicate very close comparison for the two sets of data except in Pal-3RD where a significant improvement in capacity was measured during injection that coincided with the recording of a seismic event in the area. The estimated capacity of Pal-1RD at 1.9 MPa was not measured because the maximum flow that can be delivered to the well at the time of measurement was only 160 kg/s; equivalent to a delivery pressure of 1.4 MPa. Thus it is projected that the well can accept 180 kg/s at 1.9 MPa.

TABLE 19: Comparison of theoretical estimates and actual measurements of well reinjection capacities.

Well	Design injection pressure (MPa)	Theoretical capacity (kg/s)	Actual injection pressure (MPa)	Measured capacity (kg/s)
PAL-1RD	1.9	>180	1.4	160
PAL-4D	1.8	127	1.9	130
PAL-3RD	2.1	61	2.05	130
PAL-2RD	2.1	58	2.0	40
PAL-1	1.7	161	-	-

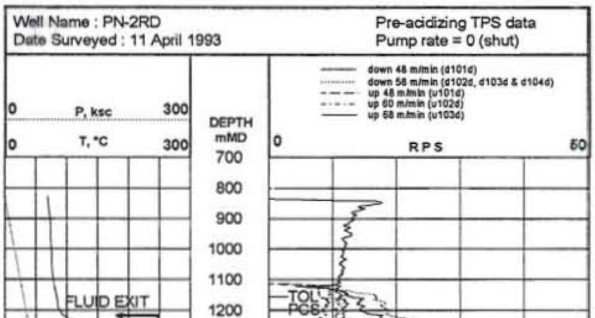


FIGURE 48: Example of temperature-pressure-spinner logs (TPS) at shut condition at PN-2RD

Temperature-pressure-spinner logging were conducted at PN-32D and PN-2RD to fully evaluate the effectiveness of the acidizing operation. It was run before and after the acidizing jobs in both wells. Figure 48 displays a typical result from PN-2RD. The spinner response in this suite of logs detected an upflow that originated at about 2800 m exiting at about 1200 m. This is shown by the higher tool response in the down-logs while the well was shut. The upflow might have been caused by the pressurization of the bottom zone as most of the reinjection fluids were being injected at this depth since plant commissioning in 1983. The estimated upflow was about 15 kg/s. Figure 49 shows the spinner response in well PN-32D before and after acidizing. The response of the tool at both logs indicates the highly irregular diameter of the hole below the casing shoe i.e. from 1150 m through 1600 m. The tool's response after acidizing was more subdued than in the logs before acidizing indicating that the hole might have been cleaned of mud cake or other deposits resulting in the enlargement of the hole. However, it is noticeable also that the spinner response at 1700 m increased after acidizing indicating perhaps that some deposits from the top section might have fallen and accumulated at this depth causing the reduction of the hole size. On the other hand, the results of the temperature-pressure-spinner indicate that thicknesses of permeable zones inferred from the conventional Kuster gauges (mechanically driven and stationary surveys) were overestimated. Permeable zones inferred as 100 to 300 m in PN-2RD were measured to be as thin as 3 to 30 m only.

Casing Perforation

With the impending decline in the total field capacity in Palinpinon and the continuing increase

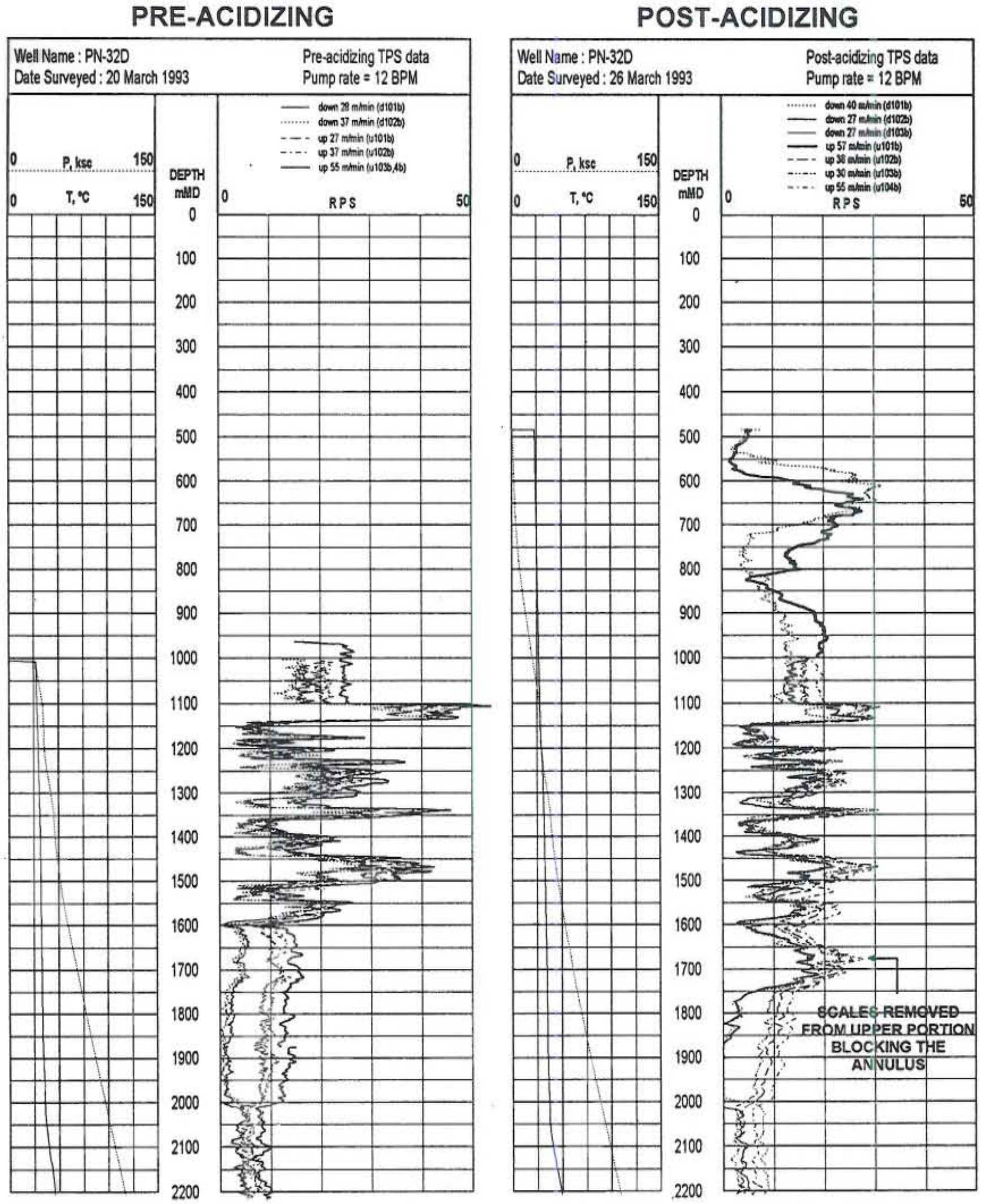


FIGURE 49: Temperature-pressure-spinner logs (TPS) showing the variation of log response before and after the acidizing job at PN-32D

of reinjection fluids that has been causing the decline in enthalpy of the production wells, a strategy of tapping the steam cap that has been formed in Palinpinon due to exploitation was identified. The shortest time and the cheapest way of doing this is by perforating the 9⅝" casing opposite the zones that are inferred to have good permeability based on losses encountered during drilling. Casing perforation is widely applied in geothermal wells in the Philippines. In conjunction with CBL surveys after cementing a casing string, perforation may be done in preparation for squeeze cementing. Examples of this activity are presented in a later section.

The method has also been proven successful by another geothermal company in the Philippines in inducing additional production from old wells. Data on these operations are, however, not available. PNOC-EDC has tried the same technique, but revisions in future programs, as will be described here, are still in order.

Shallow (600-1000 m vertical depth) two-phase zones in Palinpinon field had been intentionally cased off in the development stage of the field to minimize anticipated drawdown. Recent developments in the utilization of the field, however, have prompted PNOC-EDC to explore the possibility of opening up these zones for additional production.

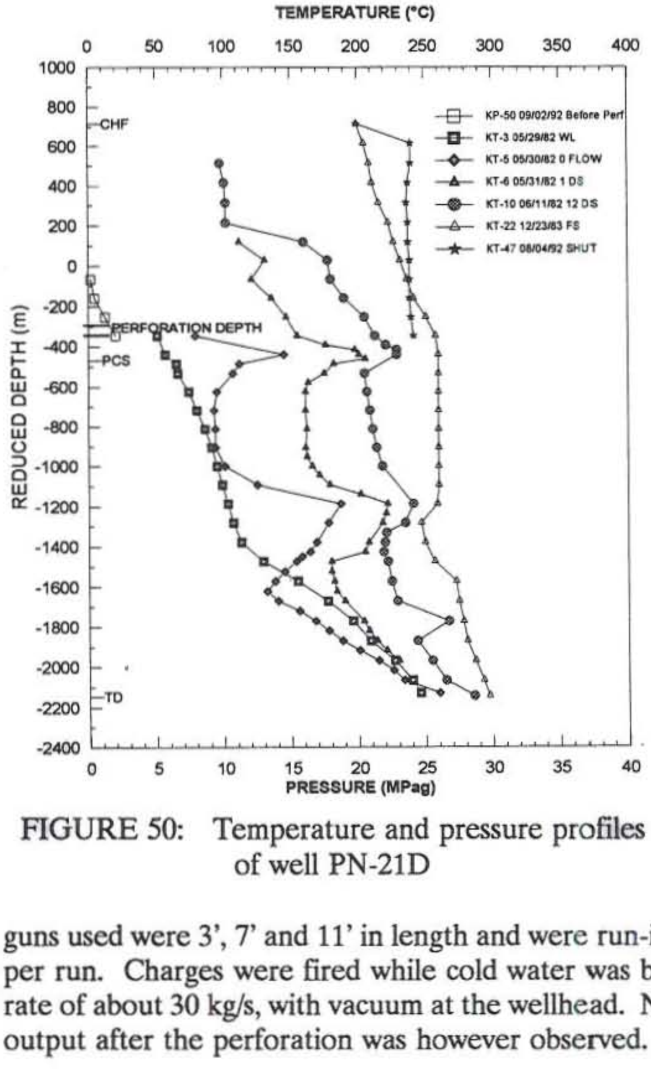


FIGURE 50: Temperature and pressure profiles of well PN-21D

PN-21D, a production well in Palinpinon 1 was made a test case for the experiment. This well displayed higher than normal temperature build-up right after its completion within a 100 m section just above its production casing shoe (Figure 50). Circulation losses were encountered within this zone during drilling, and the temperature "bulge" persisted even after 10 years of utilization of the well. Its capacity had been significantly reduced to 2.9 MW_e; and, that taking it out from the system would not affect the steam supply to the power plant.

After quenching the well, thru-wireline perforation was done on the production casing of PN-21D using 656 shots of deep-penetrating (8-11" from inner casing wall) perforation charges within a 50 m section where steam was suspected behind casing. The perforations were spaced at 4 shots/foot with 120° phasing using a combination of 4" OD and 5" OD hollow steel carrier casing guns. The guns used were 3', 7' and 11' in length and were run-in-hole in tandem to achieve maximum shots per run. Charges were fired while cold water was being injected into the well by gravity at the rate of about 30 kg/s, with vacuum at the wellhead. No indication of any improvement in the well output after the perforation was however observed.

Post analysis of the perforation activities suggests that the failure to produce steam from the perforated section was most likely due to improper selection of target depths. Target depths for perforation (1010-1060 m) were based on Kuster temperature profiles, whereas recent comparison of similar profiles with temperature-pressure-spinner logs reveals large discrepancies in depths and thickness of permeable zones. It is now believed that success in casing perforation for additional production or injection capacity may largely depend on accurate spotting of depth targets that the conventional clock-driven downhole temperature and pressure gauges may not be able to provide. The use of the rig to enable isolation of the targeted section for pressure leak testing should also be incorporated in the future so that its success can easily be determined and re-run of perforation can be done if necessary.

A cement bond survey could have also been conducted to maximize the chances of connecting through permeable channels. The series of cement plugs made at the targeted section during drilling could still be intact at the time of perforation. An acidizing job might have been able to dissolve these cement plugs and allow contact of the steam cap to the wellbore.

Plans for more casing perforation jobs incorporating the foregoing analysis are therefore being entertained.

Cement bond logging (CBL)

Cement bond logs are the most widely used electric logs by PNOC-EDC. Its importance to the company both for immediate and future use of the logs can not be further stressed than the compulsory CBL surveys for the anchor and production casing strings of every well to be drilled. This extensive CBL programme is the result of a continuing analysis of all completed wells that has a history of casing failures. In majority of the wells so far studied, such casing failures, which vary from at least two documented cases of "popping up" anchor casing (LG-1D in Palinpinon and LB-3D in Mt. Labo) to confirmed casing breaks, has been attributed to poorly bonded casing strings and/or acid attacks. In two occasions, casing perforation and squeeze cementing had been conducted after earlier CBL surveys detected cementing problems. Some of these cases are presented in the following discussions.

PAL-12D (casing break). This well has been worked over three times to clear the 9⅝" production casing and the 7⅝" slotted liner of recurring obstructions at various depths resulting in the loss of 7 downhole instruments during completion tests and periodic surveys. The third work-over operation was still going on at the time of this writing.

The first work-over in 1985 consisted of fishing out 165 m of wireline, milling of buckled casing and sleeving the 9⅝" production casing with a 7" casing. About 275 m of the 7" casing was left uncemented after the rig failed to squeeze cement, due to excessive pump pressures peaking at about 5,000 psi. Subsequent CBL tagged the top of cement in the casing annulus at 279 m from casing head flange (CHF).

The second work over involved milling of new obstructions at 477 and 2018 m, and cutting off and retrieval of 275 m of the previously uncemented 7" casing. A pressurized (1,000 psi) CBL in the 9⅝" casing from CHF to 280 m after the milling operation indicated very poor to nil bonding within the sections 88-126, 143-200, 216-225 and 236-268 m, all referred to CHF (Figure 51). No repeat CBL was done inside the 7" casing overlay.

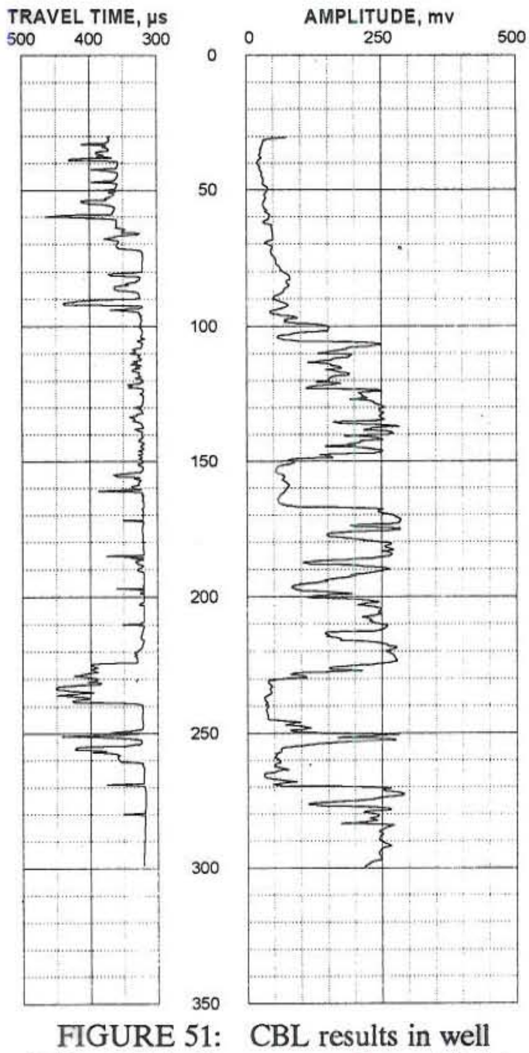


FIGURE 51: CBL results in well PAL-12D in Bacman geothermal field, where a casing break occurred at 250 m

After the second work-over, another downhole instrument (tandem KT/KP) was lost while conducting a monthly survey. Then in 1988, a new obstruction was tagged at 242 m CHF and subsequent drop in wellhead pressure was noted. Long-term pressure monitoring and casing leak tests by air compression confirmed the presence of casing leak in the well (Gerona and Relativo, 1990). Further analysis of the casing cementing history and CBL of the well (Southon and Buning, pers. comm.) strongly suggests the presence of "green cement" behind the 9⅝" production casing.

Immediate results of the on-going work-over of the well have confirmed a casing break at 242 m CHF, which lies within the vicinity of a casing collar where poor bonding was previously logged by CBL (Figure 51).

AP-3D (Squeeze cementing in the 13⅜" OD anchor casing). Persistent backflow of 5.2 bpm had been encountered in this well while drilling the 17½" hole from 236 mRKB (rotary kelly bushing) resulting in 8 cement plugs and the use of heavy mud (up to 14.6 ppg) before the 13⅜" OD anchor casing was finally set.

The backflow returned while drilling out cement inside the anchor casing, prompting the rig crew to conduct additional cementing jobs. At this stage, it was suspected that there was already channelling in the annulus between 236 mRKB and the anchor shoe. CBL surveys (non-pressurized and pressurized with 600 psi at the surface), conducted 12 days after the last cementing job confirmed the presence of channels (poor cement bond) throughout the casing annulus.

A 3-shot perforation spaced 16 linear inches apart at 120° phasing was done with the uppermost charge situated at 151 mRKB. Immediately after the shots were fired a backflow of 1.6 gpm ensued.

Another CBL survey conducted 34 hours after squeezing 87 barrels of slurry at 220 psi into the perforations indicated some improvement but a backflow of about 1.5 gpm persisted. A second squeeze of 42.6 barrels of slurry at 370 psi arrested the backflow. Another survey 45 hours after the last squeeze confirmed the success of the squeeze cementing job with the CBL amplitudes being reduced to acceptable levels throughout the hole. Although not shown in the figures, the travel time logs corresponding to the amplitude logs of all the surveys showed consistency and reliability of the results.

The well was drilled to 2730 m depth without any recurrence of the cold water backflow.

KN-2D (9⅝" OD casing CBL/VDL). This is an example of a classic textbook case of cement bond and variable density logs showing sections with poor and good cement bonding, as well as the presence of microannulus. The 9⅝" OD production casing string was set without encountering any major problem as previously elaborated in the preceding examples. Nevertheless, CBL surveys were conducted in accordance with the drilling programme for the well.

Figure 52 shows the results of a pressurized (500 psi) suite of logs. From this figure, the top of cement is estimated from the amplitude log to be at about 500 mRKB with the upper 50 m column showing poor coupling with the outer 13⅜" OD anchor casing. The sections 550-600 m, and 650-830 m have good to excellent bonding; while poor casing-to-formation coupling exists in the sections 600-650 m and 830-880 m. The vertical density logs consistently replicate the amplitude logs with the disappearance of the first wave arrival where amplitudes are seen to be at a minimum level.

The CBL equipment currently used by PNOC-EDC does not have a provision for the automatic computation and display of percentage bonding on the log, although a new set of similar equipment with such capability has recently been acquired and due to be commissioned in early 1994.

Caliper logging

PNOC-EDC uses several types of caliper tools for different applications. The X-Y and the 3-arm calipers are used, although not very often, in open hole surveys. Application of the X-Y caliper has been extended also to logging inside casing to confirm and measure extent of earlier suspected casing damage (detected by go-devil, sinker bar or lead impression block surveys) with moderate success. Its inherent limitation in delineating non-circumferential casing damage, with only four arms in contact with the casing, has led PNOC-EDC to resort to using a multi-finger casing caliper similar to the one shown in Figure 53.

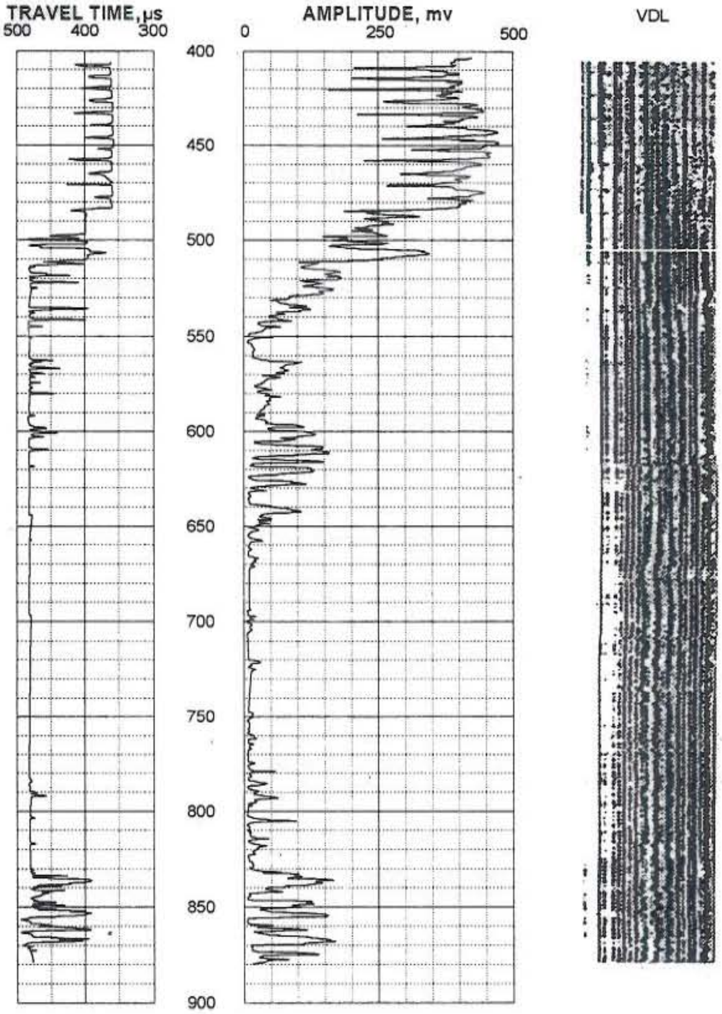


FIGURE 52: A combination of CBL and VDL log results at well KN-2D in Mt. Apo geothermal field

This caliper has 60 concentric fingers connected to individual potentiometric push rods that translate mechanical movement of each finger into electrical (voltages) signals. A downhole circuitry in the tool sorts out the signals at every logged depth and transmits the minimum and maximum to the surface electronics for recording.

As shown in the log of well OK-8RD 9⅝" casing in Figure 53, the minimum and maximum casing wall thicknesses are recorded. The log is automatically oriented in such a way that the log analyst views it as the actual 2-D profile of the casing. Thus, a deflection to the right in the minimum wall thickness plot or a deflection to the left in the maximum wall thickness plot means hole size reduction. Conversely, a deflection to the left in the minimum wall thickness plot or a deflection to the right in the maximum wall thickness plot means hole enlargement.
Prior to the caliper survey at well OK-8RD, the well was cleared of metallic junks and corrosion products at various depths. Casing breaks were also tagged and subsequently milled at about 565-570 mRKB and at 547-550 mRKB. Repeated tagging of obstructions by the drillstring at the same milled depths led PNOC-EDC to restrict the programmed caliper survey down to only 540 m depth to avoid potential damage or loss of the tool beyond this depth.

The log in Figure 53 has detected a gap in the 9⅝" casing at 100 m, coupled with progressive thinning particularly from the top. A "bleep" in the maximum wall thickness plot at the same depth indicates a 0.2 inch reduction in the ID. A plausible interpretation for this log, as may be visualized in Figure 53 is that the casing initially imploded at the collar when it was utilized as a production well in the early 1980s. (CBL suggest poor cement bonding in the annulus of the 13⅜" and 9⅝" casings at this depth.) The "localized" hole in the casing might have developed and further aggravated by progressive corrosion as suggested by the jugged nature of the log above and below the hole. At the time of the recent caliper survey, a portion of the imploded chord had not been effectively rolled during the preceding work over job - hence its detection as a 0.2" bleep in the log.

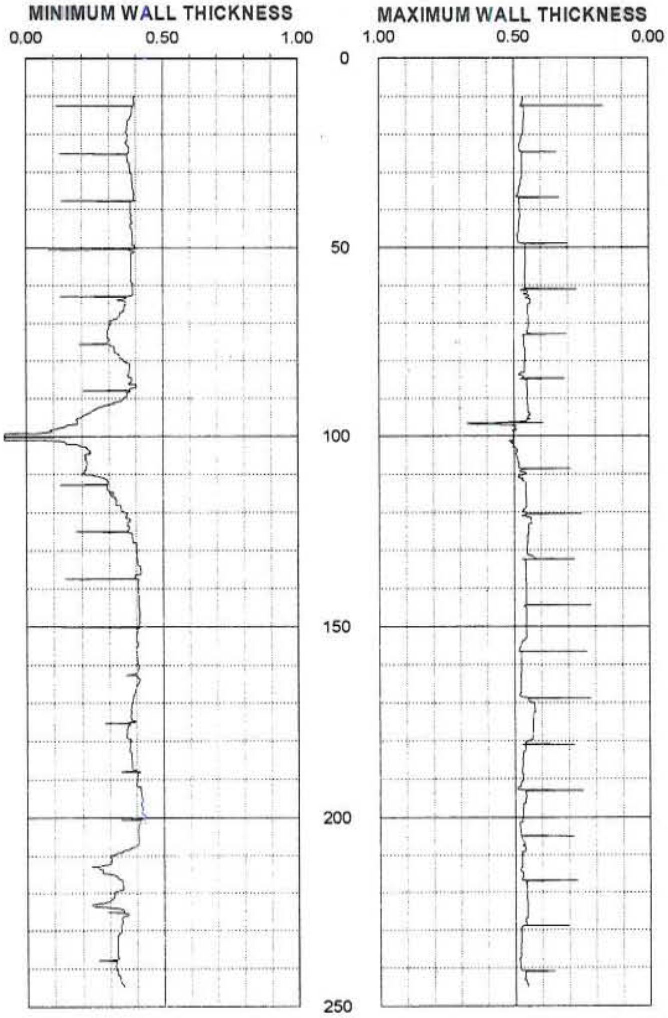


FIGURE 53: The multi-arm caliper log at well OK-8RD in the Palinpinon geothermal field

The thinning of the casing wall at 60-75 and 200-215 m is most likely due to drillpipe wear as this well has been redrilled and worked over several times.

3.5 Conclusions

The current strategies in the development and management of geothermal fields in the Philippines have been considered effective and consistent with the requirements of sustaining long term production of geothermal fields. PNOC-EDC continues to review and change its strategies and philosophies to meet the dynamic response of the reservoir as well as the changing policies on environmental protection.

4. OPTIMIZATION OF THE TONGONAN GEOTHERMAL RESERVOIR

4.1 Introduction

The need to accelerate the development of geothermal energy resources in the Philippines compelled PNOC-Energy Development Corporation to investigate the possibility of obtaining major proportion of geothermal power in the island of Leyte, and, consequently, reduce the impact of present power crisis in the country and provide additional power for future requirements

From the different geothermal areas in Leyte, PNOC-EDC expects to develop 640 MW_e on top of the existing 112.5 MW_e Tongonan I geothermal power plant commissioned in 1983. The interconnection of Cebu-Leyte through submarine cable in 1996 will require 200 MW_e while the interconnection of Luzon-Leyte will require 440 MW_e in 1997.

Table 20 shows the reserves' estimates from the various sectors in the Greater Tongonan geothermal field. The Greater Tongonan geothermal field is comprised of the Upper Mahiao, Malitbog, Mahanagdong and the Tongonan I sectors. A total of 222 MW_e has been proven at 0.6 MPaa in the Greater Tongonan Field with an additional 17 MW_e from the Alto Peak area.

TABLE 20: Reserves' estimates (MW_e) for Leyte A areas (PNOC-EDC, 1990)

Sector	Available power	Reserves
Malitbog	63	165
Upper Mahiao	104	110
Mahanagdong	55	165
Alto Peak	17	80
Total	**239**	**520**

Therefore, 520 MW_e of geothermal power is immediately available for development in Leyte for 25 years. The balance to reach the required 640 MW_e might be obtained from other prospect areas in Leyte, such as Biliran, Mahagnao or Anahawan (Figure 1). Alternatively, the currently proven power generating capacity could be increased by producing and supplying steam at higher turbine inlet pressures, at which thermodynamic and thus generation efficiencies are improved.

High pressure steam field operation has not been previously attempted at any Philippine geothermal field. This is largely due to concerns about pressure drawdown and, thus, sustainability of the four fields designed and developed in the late 1970s to early 1980s. In particular, there was little experience worldwide, except from Wairakei, with the actual behaviour of liquid-dominated geothermal fields under production. This necessarily led to conservative engineering with adoption of relatively low turbine interface pressures, e.g. 0.5 MPaa. Also, at that time, there was little capability for predicting future reservoir performance from numerical modelling methods. There was thus no rigorous basis for assessing run-down in reservoir pressure and turbine delivery pressure as a function of production.

Over the past decade, these concerns have been reduced as a result of the large amount of data gathered on the response of geothermal reservoirs to production, and the development of numerical methods that are able to closely match past reservoir performance and provide a good guide to likely future performance. It is thus now possible to predict the response of reservoir pressure with production at any given level of generation and steam field operating pressure.

4.2 Characteristics and performance of the Tongonan reservoir

Reservoir description (after Sarmiento et al., 1993)
The Tongonan geothermal reservoir is a typical volcanic-related, liquid-dominated system with a natural convective upflow of chloride brine. This brine is overlain at shallow levels by a two phase region developed in the central portions of the reservoir (Sarmiento et al., 1985; Sarmiento, 1986; Aunzo, 1986; Salera, 1987; Aquino et al., 1990). The temperature and pressure distributions suggest the upwelling to be in the Mahiao-Sambaloran sector with strong lateral flows to Malitbog and the Bao valley. This is consistent with the initial hydrological model proposed by Lovelock et al. (1982). In the natural state, the onset of the two-phase zone at deeper levels coincides with the top of the upwelling zone which is centred around wells 401, 209 and 410 (Figure 13). It propagates from a reservoir depth of -800 m relative to sea level, extending to shallow depths in Malitbog and to the surface as minor hot spring discharges and fumaroles in the Lower and Upper Mahiao areas (Figure 35).

Wells 401, 406, 407, 410 and 209, which are drilled within the upflow zone, exhibit maximum discharge pressures up to 6 MPag compared to 3.5 MPag for wells drilled in the reservoir outflow sector in the Malitbog valley. Discharge enthalpies of these wells range from 1700 to 2200 kJ/kg with two distinct zones feeding the wells. At fullbore discharge or wide open conditions, the shallow two-phase feed zone dominates, discharging fluids with enthalpies of about 1800-2200 kJ/kg. At throttled conditions, the discharge enthalpy is in the range of 1700 kJ/kg, indicating the reduction in the contribution of the two-phase zone. These discharge enthalpies are in excess of the corresponding enthalpies at saturated conditions. On the other hand, discharge enthalpies in the Malitbog sector are in the range of 1150-1250 kJ/kg, corresponding to the enthalpy of liquid water at the reservoir temperature of 260-280°C. Therefore, these wells do not show the steam addition effects seen in the Mahiao and the Sambaloran wells.

Changes in the production well characteristics
As of December 31, 1991, the total net mass and heat extracted from the Tongonan I production sector was 1,169,029 tons and 2077 TJ respectively. The Tongonan I power plant consists of 3 x 37.5 MW_e low pressure steam turbine units and has been in operation since June 1983. The turbine inlet pressure is set at 0.6 MPaa. During the period 1983-1991, the actual generation averaged only 55 MW_e. This is due to a relatively slow increase in power demand on the Leyte-Samar power grid, from a daily peak load of 35 MW_e in 1985 (dominated by the industrial load from a copper smelter complex and a fertilizer manufacturing plant) up to 90 MW_e at the present time. With an expansion to the copper smelter complex due for commissioning in the first quarter of 1993, the daily peak loading on Tongonan I will soon exceed 100 MW_e.

Figures 54, 55 and 56 indicate the field performance of Tongonan I wells since 1983. After 13 years in production, the extrapolated maximum discharge pressure by which the wells can operate is near 3.6 MPa compared to 5.2 MPa before exploitation. Certainly, the field has sufficient capacity to operate within the targeted 1.0 to 1.5 MPa (Sarmiento et al., 1993).

As a consequence of pressure drawdown after the commissioning of the power plant, the enthalpy of most of the production wells rose significantly from 1400 to 1800 kJ/kg through 1984 to 1986 as could be seen from an increase in the steam flow in Figure 54. The output ceased to increase in 1986 when it was evident that the reinjection returns from reinjection wells 1R3, 1R5D, 2R3D and 2R4D had started affecting the production wells. Well 106 appears to be the only well in the field that has not been significantly affected by the reinjection returns. It has continued to increase in enthalpy and appears to have stabilized its output at 10 MW_e. The estimated field output at 1.0 MPa taken in 1991 indicate an increase over those measurements taken in the previous years. This is evident from Figures 55 and 56.

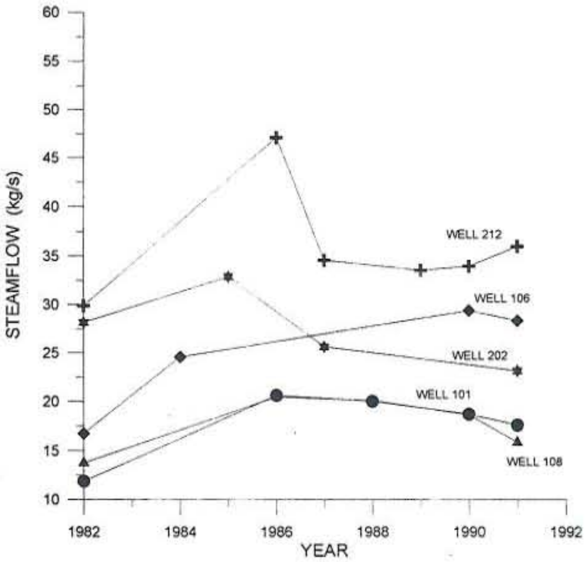


FIGURE 54: Steam flow of selected wells in Tongonan I production sector

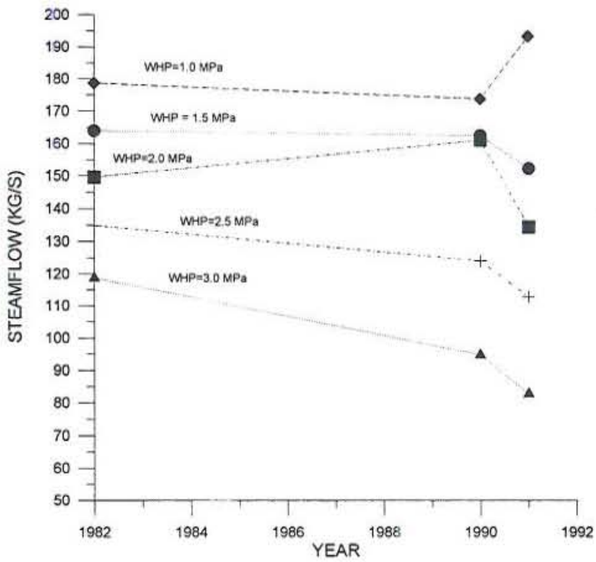


FIGURE 55: Steam output trend of selected wells in Tongonan I sector at different wellhead pressures

These results from the Tongonan I sector have encouraged PNOC-EDC to evaluate the possibility of developing the other sectors of the field that have been delineated, thoroughly tested and proven to be connected with the main Tongonan reservoir at high pressure condition.

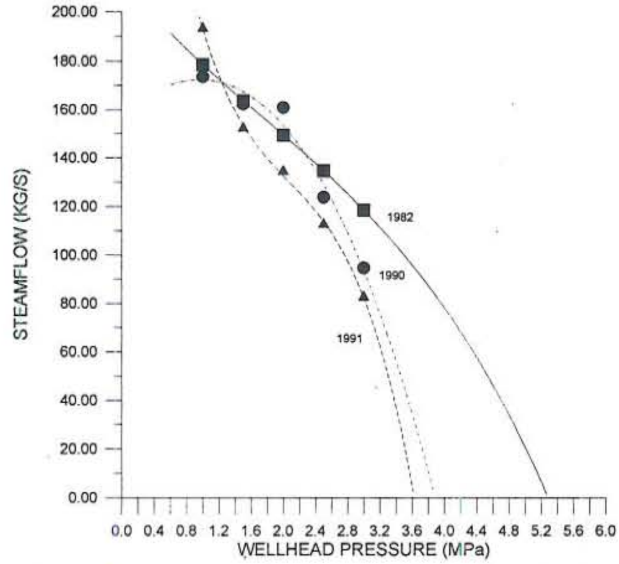


FIGURE 56: The output curves of selected Tongonan I wells taken at different periods

4.3 Performance forecast of the field

The series of numerical simulation studies conducted by Aunzo (1986), Salera (1987) and Aquino et al. (1990) on the Tongonan geothermal field serves as the basis for continuing the performance forecasting of the field at high pressure conditions. Aquino et al. (1990) shows that the field can sustain production for 25 years and at a capacity of 387.5 MW_e at 0.6 MPa turbine inlet pressure. The model that was used in their simulations and in this optimization study consists of 405 grid blocks distributed in 3 layers between the top of the reservoir at -300 and -1800 m. It was run using the MULKOM simulator (Pruess, 1982).

Sarmiento et al. (1992) discussed in detail the results of these recent simulations at 1.5 and 2.0 MPa turbine inlet pressures. The forecasts beyond 2.0 MPa inlet pressures were not conducted because of limited time. In the simulation runs, different massflows were assumed at these turbine inlet pressures to determine the (a) effects of the changes in massflows with the field performance and the number of maintenance and replacement (M&R) wells at each condition. The results are summarized in Table 21.

TABLE 21: Parameters used in the simulation of Tongonan geothermal field

Inlet pressure (MPaa)	Steam rate (kg/s-MW$_e$)	Steam flow (kg/s)		Mass flow (kg/s)		Capacity (MW$_e$)		No. of M&R wells	
		Malitbog	Upper Mahiao	Malitbog	Upper Mahiao	Malitbog	Upper Mahiao	Malitbog	Upper Mahiao
0.7	2.29	378	252	1387	687	165	110	23	28
1.5	2.29	378	252	1922	878	165-240*	110-130*	24	51
2.0	2.29	378	252	2205	642	165-290*	110-130*	29	51
1.5	1.75	289	192	1452	697	165	110	16	22
2.0	1.65	272	182	1616	922	165	110	14	20

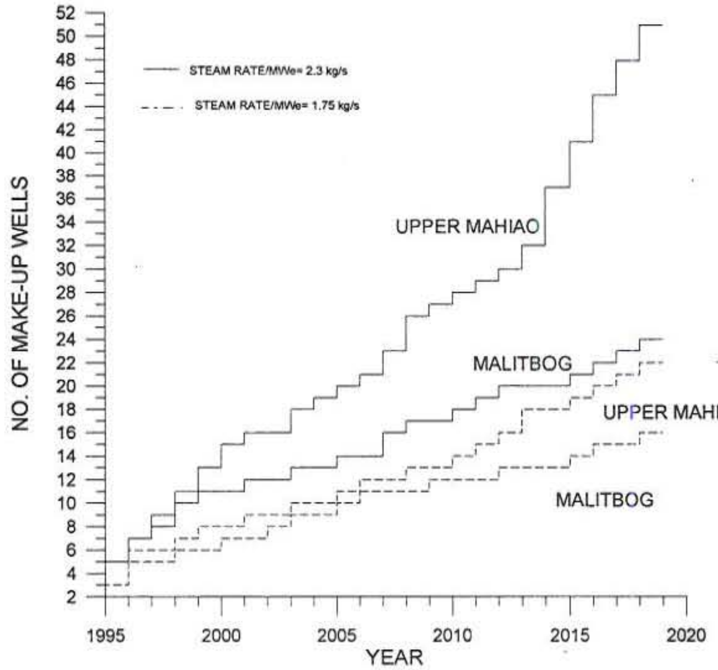


FIGURE 57: Make-up and replacement well scheduling for Upper Mahiao and Malitbog at different steam production rates

Figure 57 shows the calculated number of M&R wells for Upper Mahiao and Malitbog sectors at the above mentioned turbine inlet pressures. The graph indicates that there would be more additional wells needed in the Upper Mahiao as a result of drying-out in this sector. Earlier, Aquino et al. (1991) showed that additional reinjection fluids have to be reinjected into Upper Mahiao for pressure support and maintenance. They showed that only 29 M&R wells would be needed in Upper Mahiao in 25 years if fluids from the Malitbog sector would be diverted to Upper Mahiao compared to 38 wells if only fluids from the Upper Mahiao sector are to be reinjected back to the reservoir. In the Malitbog sector, the M&R well requirements are significantly lower ranging from 14 to 16 at much reduced steam consumption and 23-29 at higher steam rate consumption. In this study, no additional fluids were assumed to be reinjected apart from those coming from Upper Mahiao resulting in a significantly higher number of M&R wells.

Nevertheless, the results of these simulations indicate that the Tongonan reservoir can sustain production at the specified mass flows that cover the likely mass withdrawal rates for the proposed field development. It is important from the results of the simulation that pressure support in Upper Mahiao is maintained to reduce the M&R wells and avoid dry-out in the field. It appears from these results that the capacity of the sector is already maximized and that possible expansion in the future could not be justified. In the case of the Malitbog sector, it is important that strategies that would reduce the risk of thermal breakthroughs be incorporated in its final development plan. This should include drilling the reinjection wells as far away as possible.

There is about 10% overproduction in the field as the simulation assumes continuous production although the plant load is expected to average only 90%. The simulation results are therefore believed to be very conservative even if we don't consider that more cautious assumptions on field boundaries and recharge were used, i.e., closed boundary system (Mesquite, 1992; Horne, 1990).

Wellbore simulation
Figure 58 illustrates the output curves of wells 503 and 301D in Malitbog sector. These output curves were generated from the wellbore simulator GWELL by Aunzo (1990) after coupling it to the results of the reservoir simulation. The curves were generated to determine whether the fluids from each of the reservoir blocks where the wells were located could sustain the flow to the surface if pressure drops in the wellbore are considered. A more reliable prediction of the M&R well requirements can thus be achieved with the use of this wellbore simulation. The results indicate that there would initially be a drop in the massflow and wellhead pressure in the two wells from 1995 to 2000 as the reservoir pressure drops. However, the wells would then turn two phase by the year 2005 with an increase in enthalpy. The output curves indicate that the wells are choked as the wellhead pressures are higher at almost the same massflows and steam flows. There is therefore a good opportunity for bigger production by the year 2005 using large hole diameters. Since these wells are believed to be representative of the wells in the Malitbog sector, the wellbore simulation was not conducted on the other wells because of limited time. Similarly, this was not done in the Upper Mahiao because most of the wells there do not have the risk of not being able to sustain flow to the surface because of their high enthalpy and steam saturation. These results further reinforce the numerical simulation that Malitbog and Upper Mahiao can sustain production at the proposed high operating pressures.

4.4 **Power station models** (after Sarmiento et al., 1993)

In geothermal steam power generation, the turbine type dictates the steam rate and thus the number of required wells from the reservoir to generate at the required capacity. The plant configuration, i.e., the way in which single units or various combinations of turbine types are combined, influences the degree of pressure rundown and enthalpy changes in the reservoir. Sarmiento et al. (1992) evaluated seven possible power station models including combinations of high pressure (H-P) and intermediate pressure (I-P) turbines. H-P turbines are defined here as those with pressure ranging from 1.0 MPaa and higher. I-P turbines are those with pressures ranging from 0.5 to 0.9 MPaa. Only two candidate power cycles, e.g., single and dual flash cycles, were considered. There has been no experience yet in the country on the application of binary and/or hybrid systems, especially at high temperature fields like Tongonan.

Figure 59 illustrates the arrangement of turbines and separators for these power station models. The diagrams indicate 6 possible combinations of condensing and non-condensing turbines with H-P and I-P steam entries. Regardless of the plant configuration, the approach adopted here has been to ensure that all plants remain capable of defaulting to operation at a 0.7 MPaa inlet pressure in the event that reservoir pressures fall unexpectedly. As field pressures decline, the inlet pressure for the H-P back-pressure turbines will eventually exceed discharge pressures of production wells, and the H-P units can no longer be used. When this happens, the turbines can be decommissioned and transferred to a location where high pressure units are needed. This was the strategy adopted at the Wairakei geothermal field, New Zealand where the H-P turbines were shut down after several years of field rundown and much later refurbished and installed at Ohaaki

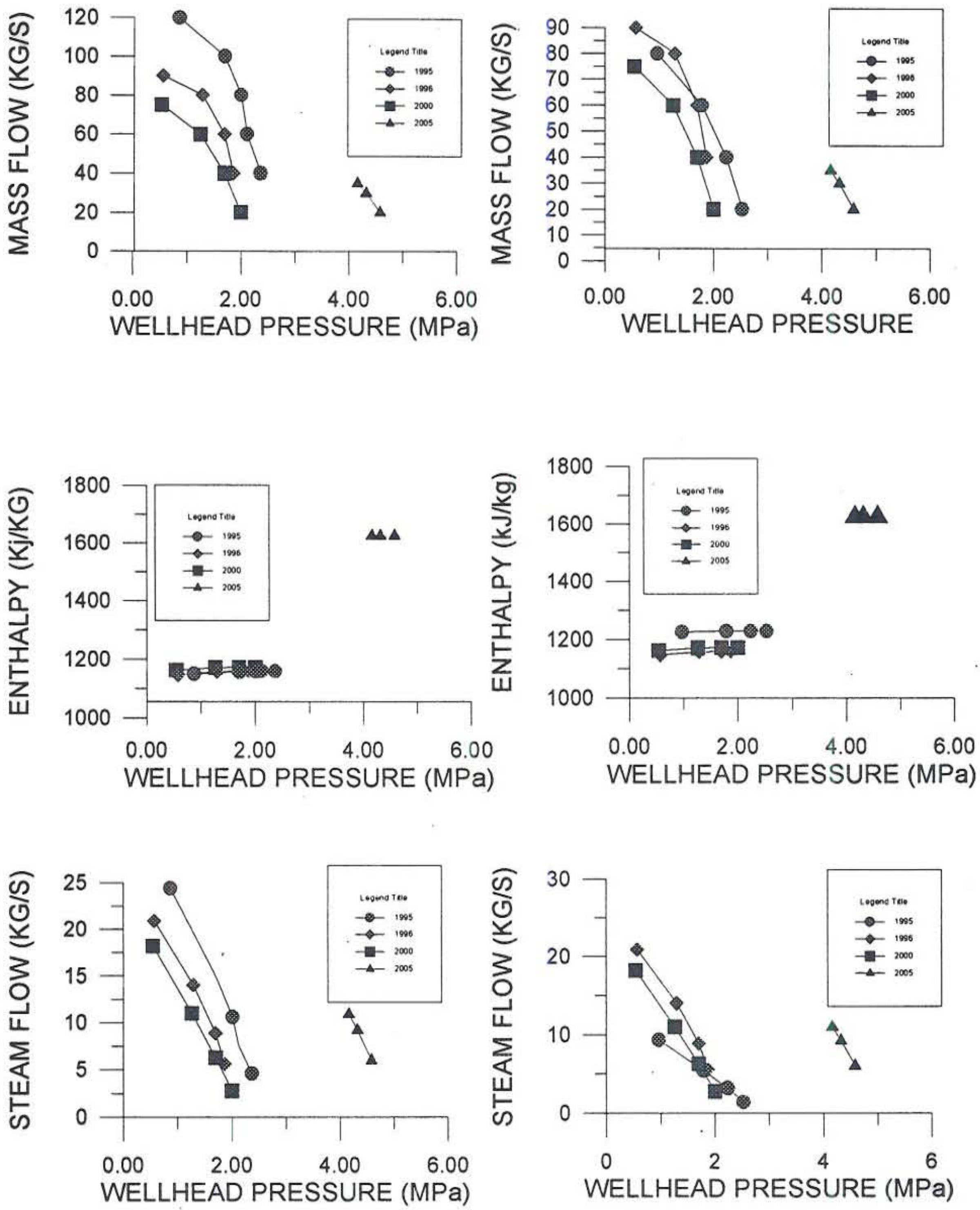


FIGURE 58: Predicted output curves of wells 301D and 503 after coupling the reservoir simulation results with a wellbore simulator

to take advantage of the high pressure steam available in that field. Alternatively, the high pressure direct condensing turbine can be modified to operate at a lower steam inlet pressure, consistent with lower steam field production pressures. As an example, Dobbie (1991) reported that AMOSEAS has adopted this scheme for the Darajat geothermal project in Indonesia. In this

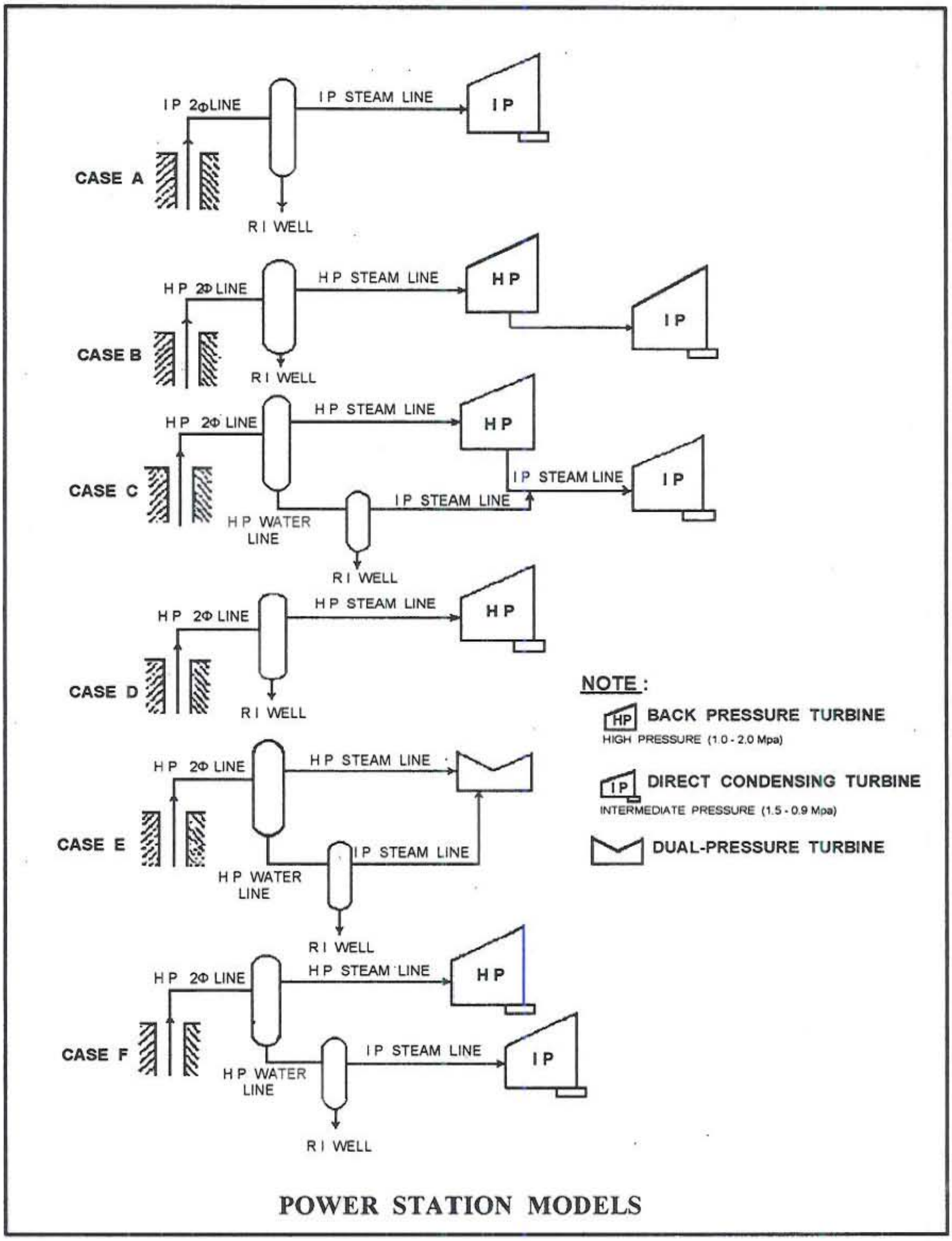


FIGURE 59: Power station models used in the Tongonan reservoir and process optimization

particular case, the initial turbine inlet pressure has been set at 1.3 MPaa. The units will later be rebladed to allow an inlet pressure of 0.6 MPaa after 9-10 years as estimated from numerical simulation.

Process optimization

The process optimization of the system was done by fixing the steam rates required to maintain the respective 110 MW_e and 165 MW_e generation of Upper Mahiao and Malitbog to cover their default operating condition at 0.7 MPaa. These steam rates are presented in Table 21.

As an initial optimizing parameter, the number of wells required to generate the above capacity based on the average well production was calculated The resulting output at various power station models was also calculated and the ratio "MW/well" at each pressure and station model is determined to establish the optimum pressure. The optimum pressure should lie in the point where the ratio is higher since you will need only a small number of wells to produce the same capacity. Besides, the drilling cost is by far the largest component in any steam field development and therefore reducing the number of wells significantly reduces the development cost. Among the different station models, Case C gives the maximum "MW/well". The results for Case C and Case D are shown in Figure 60. The optimum pressure in Malitbog lies at 1.3 MPaa, while that for Upper Mahiao is found to be between 0.9 to 1.1 MPaa for Case C and Case D respectively. The difference between the two cases is not really significant for Upper Mahiao.

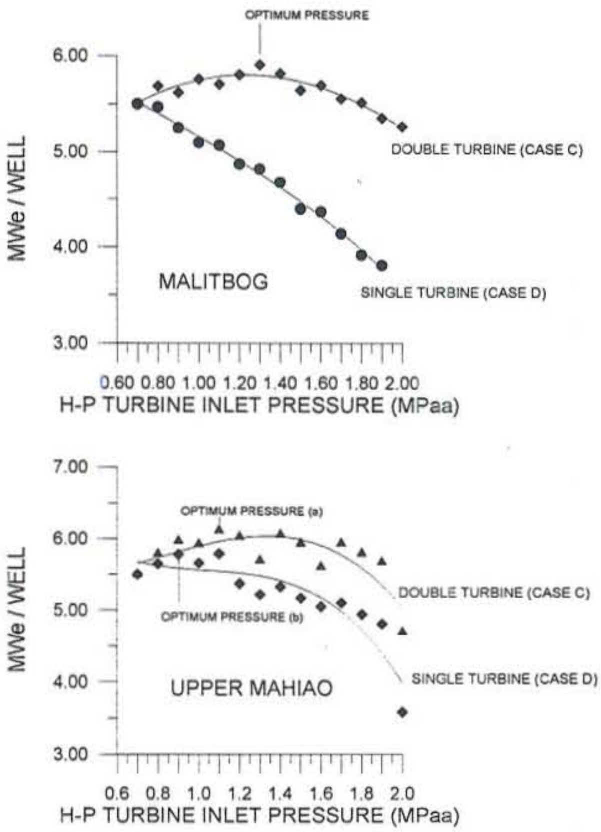


FIGURE 60: Results of initial optimization for the Malibog and Upper Mahiao sectors

In the final optimization process, the more realistic steam rates based on the recent design of efficient turbines are used. As an example, the recently delivered turbines in Bacman of 2x55 MW_e have steam rate conversions and efficiencies shown in Figure 61. These steam rates were then used to determine the respective capacity of Malitbog and Upper Mahiao from the existing wells at Cases C and D over the whole range of I-Ps and H-Ps. From the results plotted in Figure 62, the optimum pressure in Malitbog is 1.1 MPaa using the double turbine. The total field output at this Case is about 121 MW_e. This is almost the same output as Case D (single turbine) at 0.6 Mpaa. However, in view of the reduced cost of piping and power plant cost due to reduced steam rates, it is preferred that this pressure is adopted for Malitbog.

In the case of Upper Mahiao, the optimum pressure is found to be at 0.9 MPaa for the single turbine where the output is calculated to be 74 MW_e. For the double turbine, the optimum pressure lies at 1.0 MPaa where the output is 73 MW_e. Unlike in Malitbog, the output in Upper Mahiao at low pressures are much higher because the discharge enthalpy and steam fraction are also higher at these pressures. The advantage of adopting a double flash (double turbine) in this sector is mininimal, and, with a reduced risk that the enthalpy will fall with time, a double turbine is not recommended here.

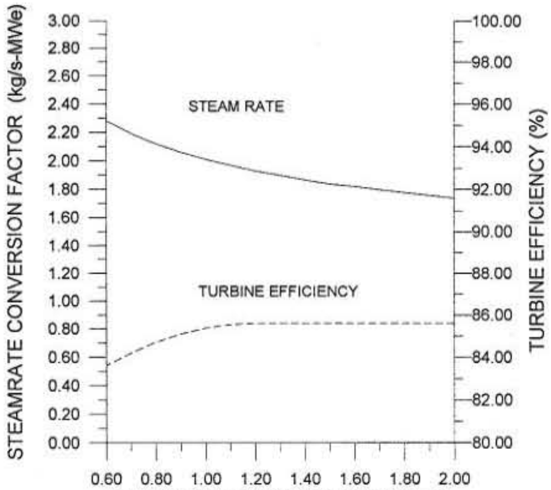


FIGURE 61: Steam-rate conversion and turbine efficiencies used in the process optimization

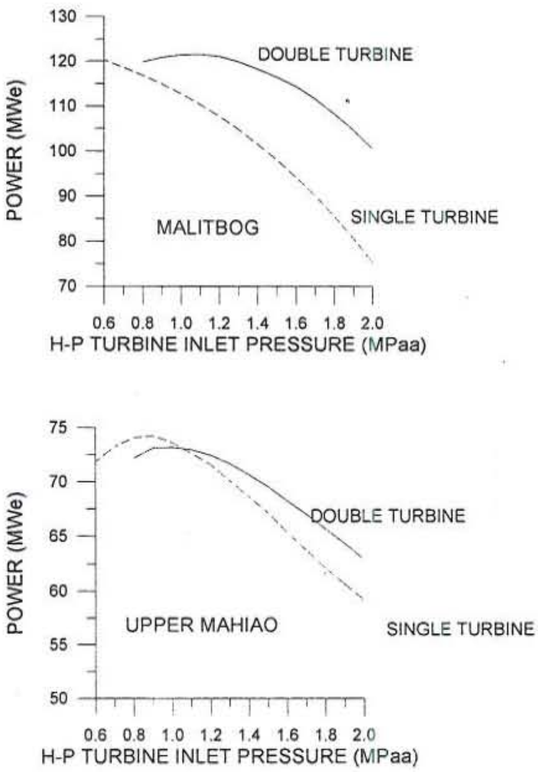


FIGURE 62: Final power optimization curves for the Upper Mahiao and Malitbog sectors

4.5 Conclusions

The performance of the Tongonan I sector during the last 10 years and the results of numerical simulation studies have justified the development and operation of the Tongonan geothermal field at high pressure operating conditions. All sectors, including the Tongonan I, Upper Mahiao and the Malitbog, could support a high-temperature, high enthalpy discharge throughout the life of the field. However, the potential threat from massive reinjection in the Malitbog sector and the danger in Upper Mahiao of drying out should be addressed in the long-term development strategy of the field. An average of one M&R well per year will need to be drilled at Malitbog and Upper Mahiao to sustain the proposed level of development.

Based on the power plant type (dual or single flash) and process optimization, a substantial improvement in the power recovery can be achieved by utilizing high pressure steam relative to the current strategy of installing I-P (0.7 MPaa) turbines. The optimum pressures determined from the process optimization are 1.1 MPaa and 0.9 MPaa, respectively, for Malitbog and Upper Mahiao. The higher pressures (1.5-2.0 MPaa) and, consequently, higher mass withdrawal considered in the various simulation runs indicate that the field can sustain 395 MW_e production for a 25 year life. Therefore, the certainty that the field can sustain production at 0.9 MPaa for Upper Mahiao and 1.1 MPaa for Upper Malitbog, is very high. This is because the mass withdrawal rate at these pressures are considerably lower than those at higher pressures.

From these results, the proposed level of development for Upper Mahiao, Malitbog and Tongonan I has been increased from 387.5 MW_e to 507.5 MW_e (including the existing 112.5 MW_e at Tongonan I). A total of at least 640 MW_e reserves has now been estimated for the Leyte A with the additional 165 and 80 MW_e from Mahanagdong and Alto Peak areas, respectively.

5. A CASE OF RESERVOIR RESPONSE TO CHANGE IN REINJECTION STRATEGY: THE PALINPINON I PRODUCTION FIELD

5.1 Introduction

The Palinpinon geothermal field is located in the island of Negros Oriental (Figure 1) along the coalescing slopes of Mt. Cuernos de Negros and Mt. Guinsayawan where a large number of surface thermal manifestations are found. Exploration in the area started in 1973 through the Commission on Volcanology and then resumed by the National Power Corporation in 1975. PNOC-EDC took over the project in 1976 and started drilling two shallow exploratory holes N1 and N2 that have temperatures of 206 and 175°C respectively. These wells had intersected strong crossflows at depth associated with the outflow of the geothermal resource. Subsequent drilling in 1978 at the inferred upflow area of the resource confirm higher temperatures of >290°C at OK-4 and OK-5. The successful discharge of OK-5 led to the development and subsequent commercial operation of the 112.5 MW_e power plant in 1983. Additional exploration drilling in the western half of the field in Nasuji and Sogongon sectors confirmed an 80 MW reserve capacity that can be tapped for expansion. To date, the Palinpinon field celebrates its 10th year in operation with about 4,145 GWh of total power generation.

5.2 Reservoir description

The Palinpinon geothermal reservoir is a typical liquid dominated system with an upwelling temperature of >320°C associated with the heat source beneath the Mt. Cuernos de Negros. Structural faults control the main permeability throughout the field with indications of very minor lateral permeability associated with the lavas and breccias of Southern Negros Formation and the Okoy Sedimentary Formation. The most prominent of the structural faults that has affected both the production and reinjection wells because of their interconnection is the Ticala fault. This fault has been intersected by majority of the wells, either at the cased off and bottom sections, and runs through the centre of the field in a northeast-southwest direction (Figure 63). Other faults that have been inferred to play major roles in the fluid circulation of the system include the Puhagan, Puhagan Splay C, Odlumon and Lagunao Faults for the Palinpinon I sector.

The subsurface temperature distribution shown in Figure 64 together with well chemical data indicates a flow of fluid northeast, north and west from a source beneath the high country to the south of Puhagan. Pre-exploitation data indicate that minor two-phase fluids already exist in the field at the top of the inferred upflow zone close to the OK-5 (Balas-balas) and the Lagunao sectors (Figure 65). Wells in these sectors discharge high enthalpy to superheated steam (LG-1D), although it is possible that the test conducted on the latter was already affected by the drawdown caused by Palinpinon exploitation. To the west, the fall in temperature is accompanied by a progressively dilute fluid indicating mixing of reservoir fluid with less mineralized and presumably cooler fluids. This differs from the flow to the northeast that is very likely controlled by fault. Fluid along this path is not significantly diluted but appears to be cooled by conductive heat loss to the surrounding cooler rocks (PNOC-EDC/KRTA, 1983).

5.3 Initial development strategy

As indicated in the company's production and reinjection philosophies, the rugged terrain imposed in the general vicinities of the resource compelled PNOC-EDC to adopt a compact development scheme in drilling the wells at several pads that are adjacent to each other. The location of the

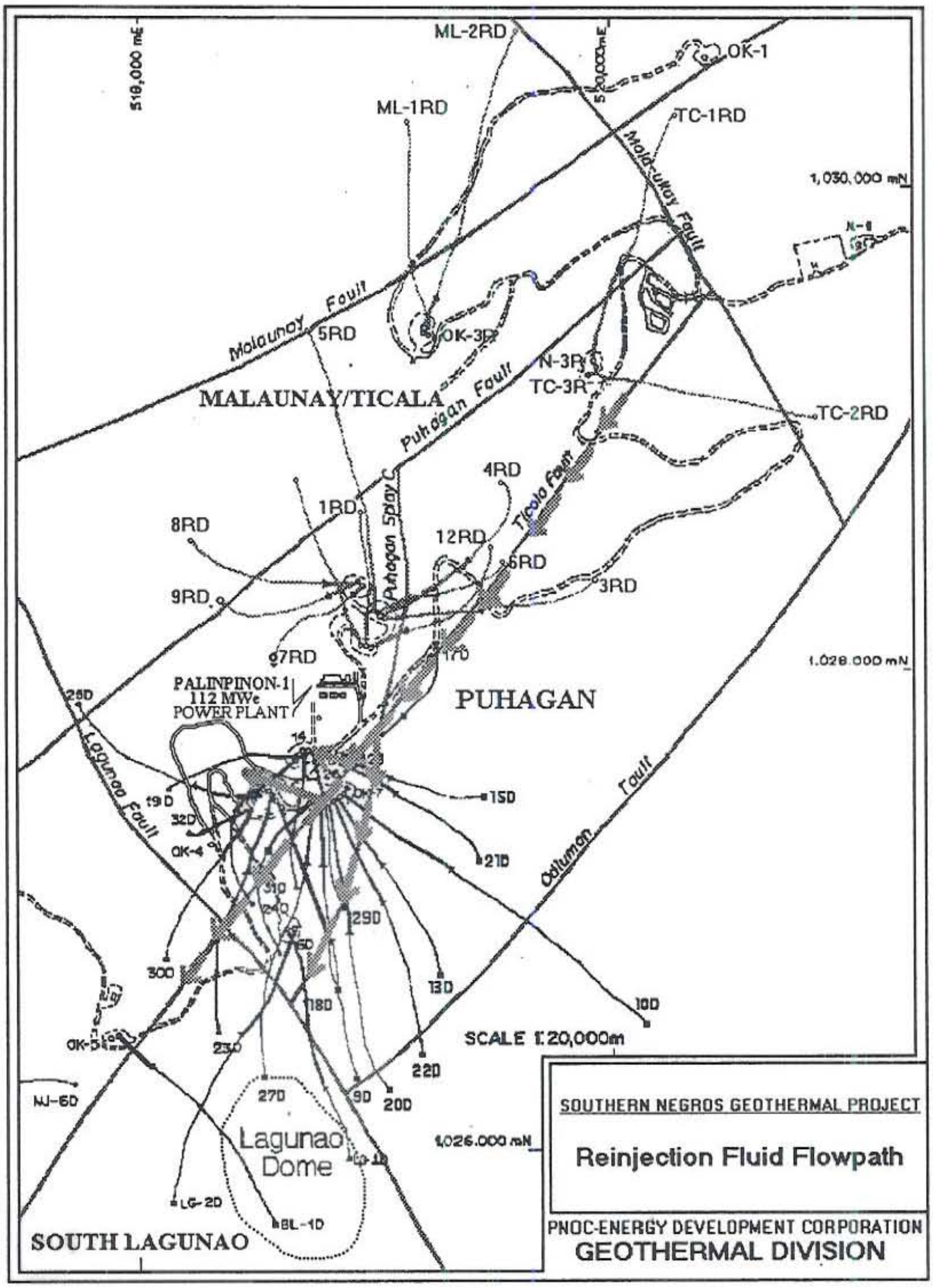


FIGURE 63: Location of wells, major structures and reinjection fluid flowpath in the Palinpinon field (after Seastres, pers. comm.)

upflow region at higher elevation and the corresponding lower elevation of the outflow region favoured the adoption of gravity reinjection further down into the Puhagan area.

The 112.5 MW_e power plant is being supplied by 22 production wells drilled on 4 separate production pads. The geothermal brine was initially being reinjected into 12 reinjection wells that are targeted north of the main production sector. These reinjection wells are in general accepting the brine at permeable zones with a minimum and maximum distance of 500 m and 2,300 m

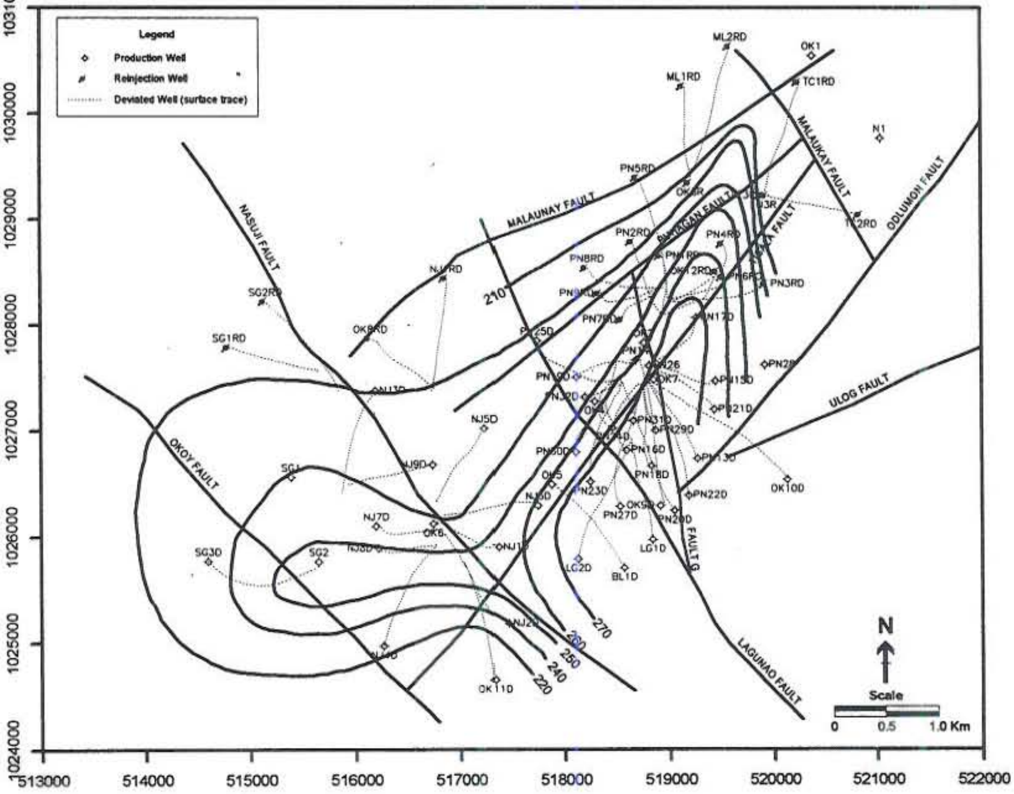


FIGURE 64: Temperature distribution in the Palinpinon geothermal field at 500 m b.m.s.l.

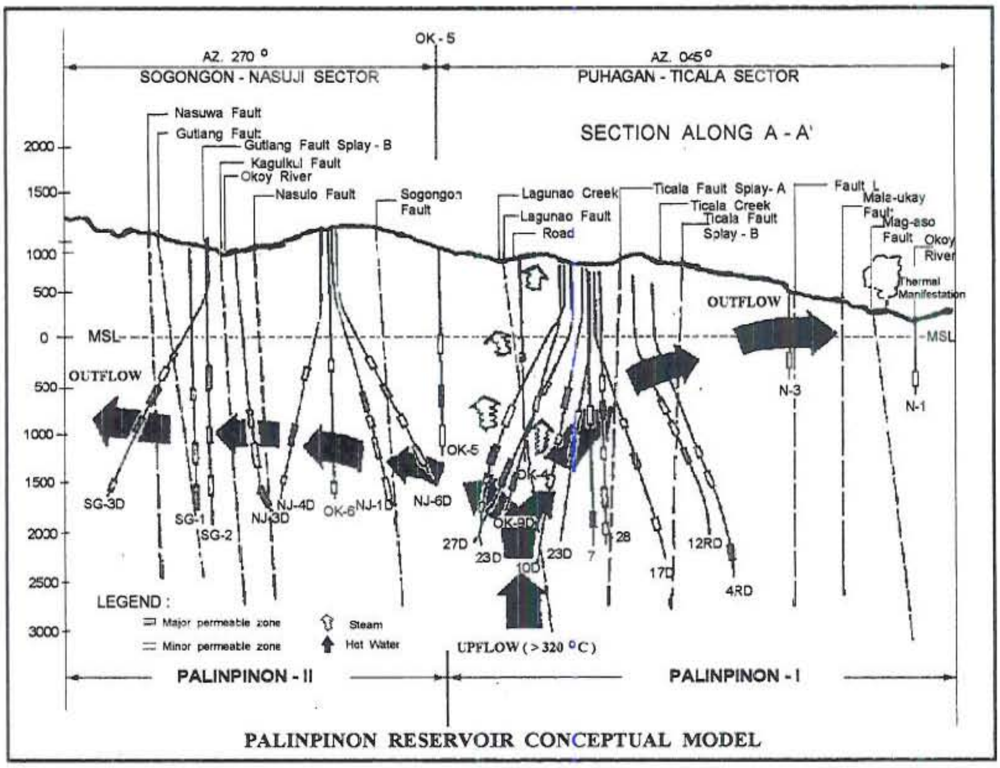


FIGURE 65: Conceptual model of the Palinpinon geothermal field

respectively from the production wells. While there is difficulty maintaining reasonable distance between production wells because of their proximities in the surface, a well spacing of at least 250 m between production zones is imposed to avoid production interference in the future. The production and reinjection wells are drilled to a depth of 2600 to 3000 m with the 9⅝" production casing set at about 1500-1700 m from the surface. This compact development scheme for Palinpinon was the first ever designed in the world made possible through directional drilling technique, and it is now being duplicated elsewhere with similar rugged and precipitous terrain.

5.4 Palinpinon I power station loading

The Palinpinon I power station was designed and constructed to operate as a variable load station since it was the largest power station in the Negros Grid. It was also cheaper to operate compared to the other smaller thermal plants that are fuelled by oil. A typical daily load curve of the power station is shown in Figure 66. The monthly average gross generation of the Palinpinon I power station is shown in Figure 67. The power station was initially operated at a low load (10-15 MW_e) during the first year of operation since the transmission lines and distribution system on the island of Negros were still being constructed then. A step increase in load was realized in July 1984 with the completion of the transmission line to the Bacolod area in the western side of Negros province. The load gradually increased as the distribution system of the electric cooperatives in the eastern and western side of Negros island was completed progressively. The load in the whole island of Negros peaked only up to 54 MW_e corresponding to 50% of the total capacity. The excess power was then exported to the island of Panay through submarine interconnection that started in October 1990. Subsequently, the grid realized a step load increase from an average of 48 MW_e in September 1990 to 82 MW_e by January 1991

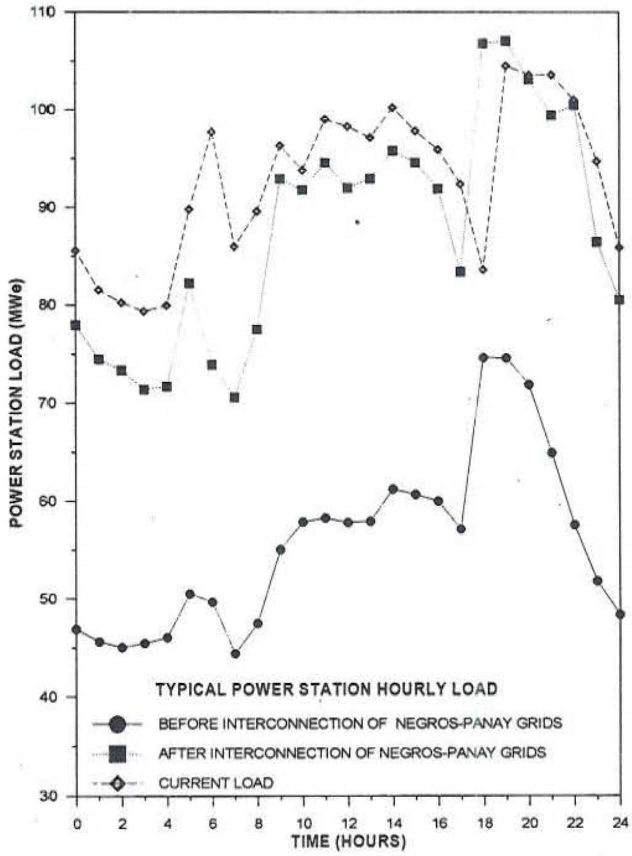


FIGURE 66: Typical daily load curves of the Palinpinon power plant

The variable load and the low demand for electrical power have resulted in the intermittent utilization of production and reinjection wells. This scheme accommodated the surface equipment maintenance activities and the well testing programs. Similarly, this scheme allowed observation of the reservoir response to the different field operating schemes adopted to better understand the behaviour of the production and reinjection wells during the exploitation period.

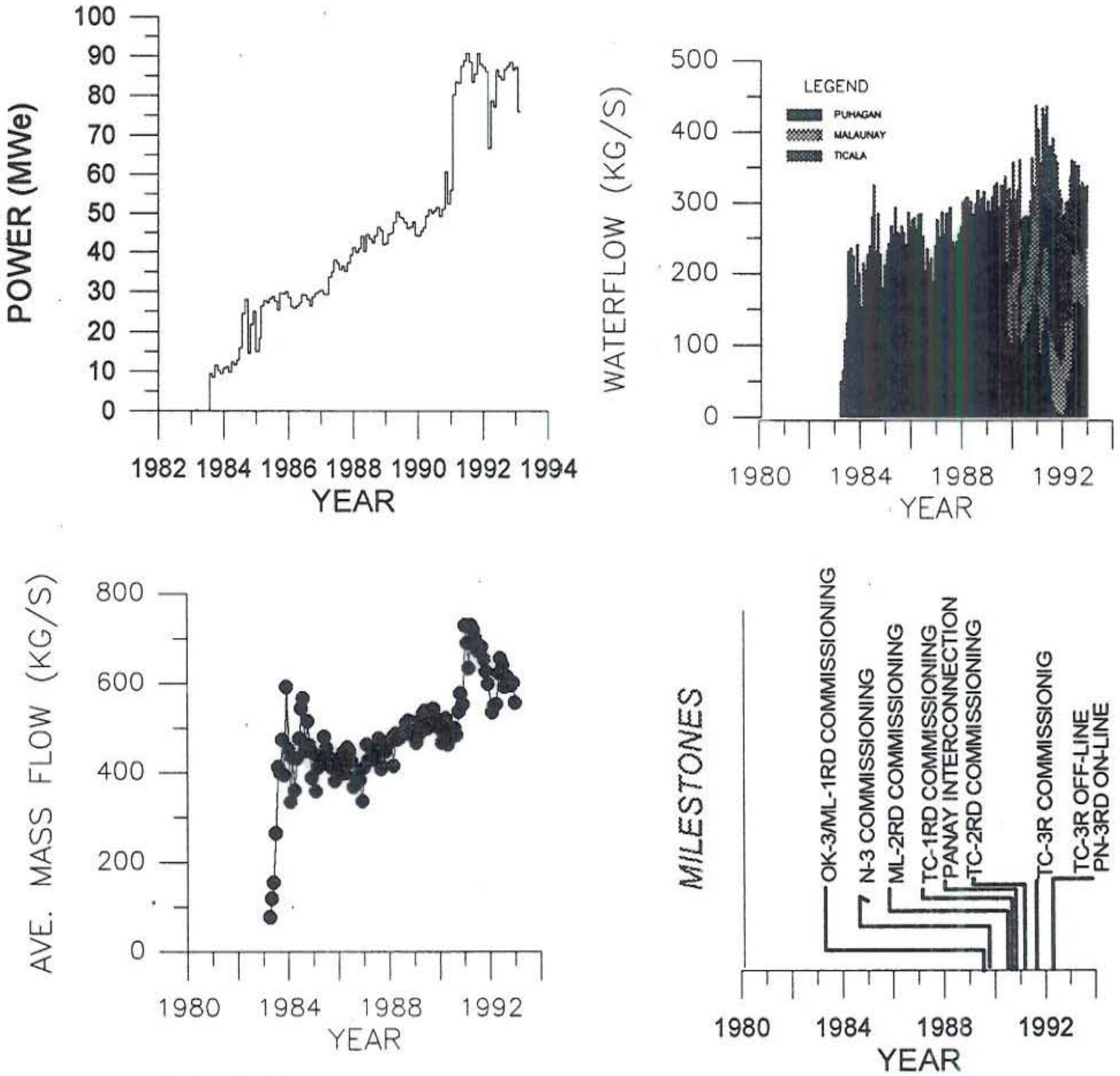


FIGURE 67: Average monthly load, mass extraction and reinjection rates with major milestones in the management and operation of the Palinpinon field

5.5 Palinpinon I mass withdrawal and reinjection

The monthly average mass withdrawal rate from the Palinpinon I reservoir since the commissioning of the power station is shown in Figure 67. Although the load on the power station was very low during the first year of operation, the average mass withdrawal rate was excessively more than the requirement of the operation of the power station, i.e., from 280 kg/s in 1983 to a maximum of 590 kg/s. The high mass extraction rate was largely due to the limitations of the control system of the fluid collection and disposal system which did not allow instantaneous trimming of the steam supply to match the variable steam requirement of the station. The frequent well testing activities during the initial stage of exploitation also accounted for the excess in the mass extraction rate. The installation of remote control valves in 1985 enabled the trimming of the blow-off to level where the plant can be safely operated. The mass withdrawal rate then varied only from 360 kg/s to 480 kg/s from the period 1984 to 1987. As the load gradually increased from 1987 to 1990, the mass withdrawal rate also increased gradually from 420 to 550 kg/s. A step increase in mass withdrawal occurred in October 1990 after the completion of Negros-Panay grid interconnection. The mass withdrawal rate increased from 480 kg/s to a maximum of 720 kg/s in January 1991. The mass withdrawal gradually declined to approximately 600 kg/s in January 1992 as a result of increasing steam output due to the increased enthalpies observed in some production wells.

The monthly average mass reinjected into the Palinpinon I reservoir is similarly shown in Figure 67. The mass reinjected during the first year was 53 kg/s but gradually increased to 258 kg/s in June 1984. It further increased to 327 kg/s when the load increased in July 1984 after the completion of transmission lines in the western province of Negros. During the period, the waste fluids from the field were reinjected to the 12 reinjection wells drilled along the Puhagan sector, e.g. PN-1RD, PN-2RD, PN-3RD through OK-12RD (Figure 63). Close monitoring of the production wells then indicated the potential risk of output decline from the production wells due to ingress of reinjection returns to the wells that have rapid communication with the reinjection sector. This concern on output decline led to the utilization of OK-3 and N-3 as reinjection wells and the drilling of additional reinjection wells in the Malaunay (ML-1RD and ML-2RD) and Ticala (TC-1RD, TC-2RD and TC-3R) areas where the inferred structural faults that served as conduits to the waste water to return to the production sectors were either cased-off or avoided. The reinjection load in Puhagan was eventually reduced to 100 kg/s in January 1990 with the connection of these wells in 1989 and 1990. However, the increased load after the Panay interconnection and the subsequent reduction in the capacities of the reinjection wells in Malaunay and Ticala increased anew the reinjection load to Puhagan to 180 kg/s in January 1990. However, a reduction of this reinjection load occurred through the drilling and utilization of TC-2RD in February 1991 and later well TC-3R, a shallow well drilled to replace N-3 as a reinjection well. This well had been accepting more than 150 kg/s for about 6 months when it was cut-off because of its negative effects on the production wells. PN-3RD was put back on line to absorb the load of TC-3R until such time that this had to be cut-off again, when signs of its negative effects were also observed.

5.6 Reservoir pressure response

Pressure decline in an operating field is usually observed as a consequence of mass withdrawal but the magnitude to which it is observed depends on the reservoir properties like storativity, recharge and permeability. In the Palinpinon field, where the major permeability is controlled by faults, rapid pressure drawdown was observed. Figures 68 and 69 show the pressure trends with time in some selected observation wells in the field. The pressure data were taken from the pressure control point of the wells extrapolated at reference depth of -1000 m (m.s.l.).

In the northern sector of the Puhagan (reinjection area), e.g. OK-12RD, the pressure remained undisturbed after the commissioning of the Palinpinon power plant mainly due to the balancing effects of the mass withdrawal from Puhagan and reinjection to the sector. However, the pressure started to increase in 1985 and continuously in 1989 due to the increase in reinjection load in Puhagan resulting from increase in power generation. A similar trend was also observed at the northeastern sector of Puhagan in PN-7RD and PN-9RD. The only difference is that there was a more pronounced response (pressure decline) in PN-9RD during the initial production period due to its proximity to the production sector. However, all these wells exhibited pressure decline when bulk of the reinjection load was shifted late in 1989 to late 1991 at the Malaunay and Ticala reinjection wells, e.g., at N-3, OK-3, ML-1RD, TC-1RD, TC-2RD and TC-3R. From 1992 and

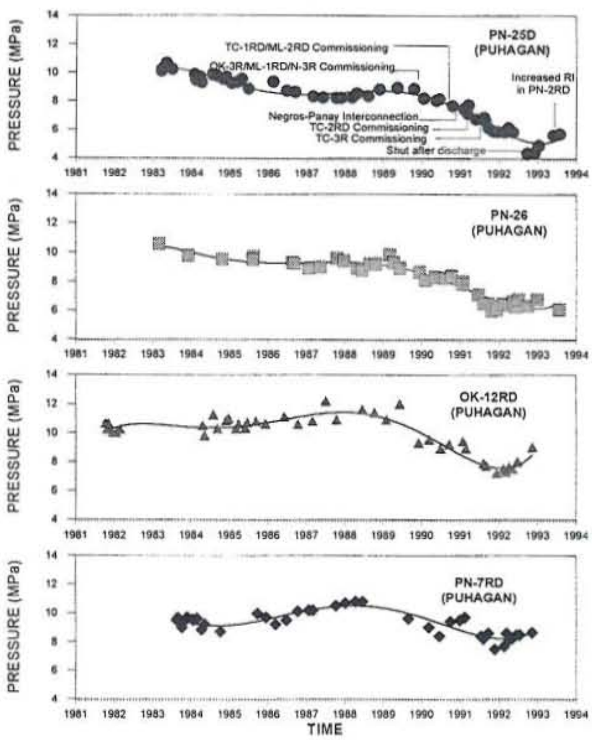


FIGURE 68: Reservoir pressure trends (at 1000 m b.s.l.) in the Puhagan sector

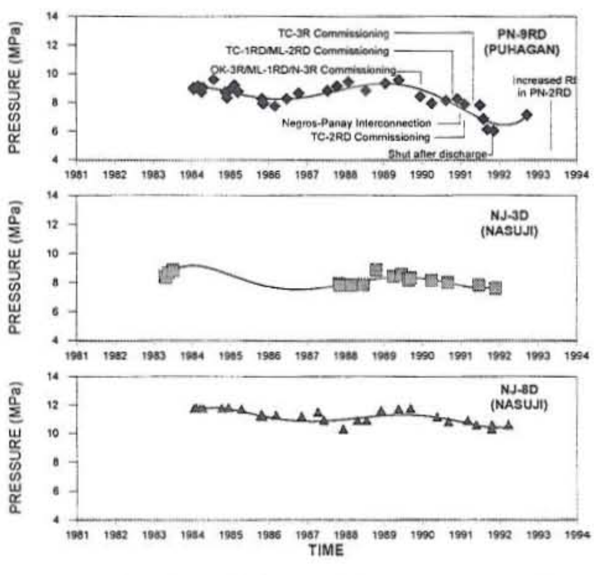


FIGURE 69: Reservoir pressure trends (at 1000 m b.s.l.) in selected wells in the Puhagan and Nasuji sectors in Palinpinon

up to the present, the pressure fluctuates but otherwise remains stable indicating quasi-steady state condition. The latter portion of the pressure plots appear to be responding to the utilization of TC-3R and PN-3RD, but it is not clear how each of these two wells affects them.

In the western production sector of Puhagan, a consistent decline in the pressure trend of PN-25D is observed. This well has never been on production as it could not sustain a commercial wellhead pressure during the initial exploitation period. Similar to the observations in the reinjection sector, the pressure rapidly declined with the shifting of the reinjection load to the Malaunay and Ticala sectors. This implies that its connection is more on the production sector than the reinjection sector. The relatively flat curve through 1987 to 1989 indicates pressure support from the Puhagan reinjection sector as the fluids return to the Puhagan sector. As the pressure continues to decline, the wellbore fluids attain two-phase and saturated condition. The well started to produce commercially sustaining approximately 1.4 MW at 0.97 MPa. The pressure later increased by 1.0 MPa when the injection load at PN-2RD reached 198 kg/s, after the acidizing job. The pressure data from pre-exploitation to date indicate that the pressure decline in this well is now 6.0 MPa.

In the central Puhagan sector, the pressure trend also assumes that of the PN-25D as shown in PN-26. This well is a vertical well and was out of production since May 1988 when it could no longer sustain the operating pressure of 0.7 MPa. The most recent pressure data indicate that the pressure drawdown in this part of the field has reached 4.5 MPa. The pressure stabilization from 1992 to date is consistent with that observed in PN-25D at the latter part of the plot. It now appears that a steady state condition is attained at the present loading in Palinpinon, but it is difficult to predict whether this will not change.

The results of pressure monitoring on selected wells in Nasuji and Sogongon give indication on their hydrological connections to Puhagan production and reinjection sectors. There was initially a minimal drawdown in both sectors compared from those observed in Puhagan wells. However, the sector exhibited a 0.5 MPa drawdown starting in 1985. It further increased and stabilized to 0.8 MPa in 1988 until the implementation of reinjection shifting to Ticala and Malaunay. By mid-1991, the pressure decline in NJ-8D had already reached 1.5 MPa. Figure 69 shows the same pressure trends related to the other wells.

5.7 Changes in downhole temperatures

It is difficult to track down the field wide temperature changes owing to the scarcity of data from the production wells. The immediate response of the wells to changes in the reinjection well utilization can mask all temperatures attained before any change in the well utilization. As an example, there is no direct correlation on the irregular changes in the downhole temperatures of well PN-26 since the start of exploitation to any event during the 10 year period, including the period when reinjection had shifted to the Ticala and Malaunay sectors. There has been an on-and-off recovery in temperatures at three depths, i.e., at 1600, 1700 and 2600 m (Figure 70). However, it was only at 1700 m where a recovery in temperature had occurred that can be associated to the commissioning of TC-1RD and ML-2RD. The temperature at 2600 and 1700 m rapidly declined with the commissioning of TC-3R in the second half of 1991, but recovered quickly while the well was still on line. It is thus difficult to correlate these two observations. To date the temperatures at 1600 and 1700 m appear to have stabilized to 220 and 230°C, respectively, although no significant increase has taken place. The temperatures at 2600 m have recovered to pre-exploitation level at close to 300°C but are still fluctuating to a certain degree. With a low temperature at 1600 and 1700 m, this well would remain non-commercial. It is likely that its temperatures can not recover until there is a significant reduction in the amount of these fluids returning to the Puhagan sector.

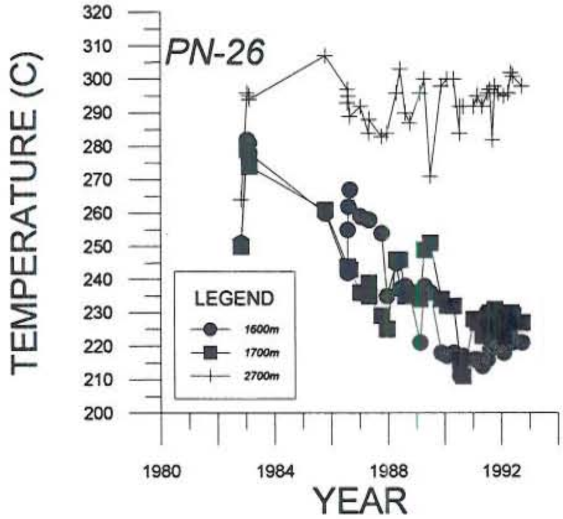


FIGURE 70: Temperature trends in well PN-26 at selected depths

Figures 71 and 72 compare the flowing and shut temperature profiles of PN-26D from 1983 through 1993. It is evident from Figure 71 that there was production from the bottom zone with temperature of 310°C, but an inflow of relatively cooler fluid was already evident in those surveys as shown by a minor kink at -1000 m. At shut condition, this kink became more pronounced with the existence of the downflow originating at -1000 m. Flowing surveys in 1988 indicate that the zone at -1000 m was dominating the discharge with temperature of 230°C (Figure 72). Under this condition, the well collapsed and ceased production to the power plant because it could no longer sustain a commercial pressure of 0.7 MPa.

Figure 73 similarly compares the flowing profiles of PN-29D from 1988 through 1989. In these profiles, we could see the two cases where the production profile was either controlled by the bottom or the top zones. In 1988, a flowing survey conducted revealed that the main production was coming between -700 and -800 m with a downflow running in the hole. During this period,

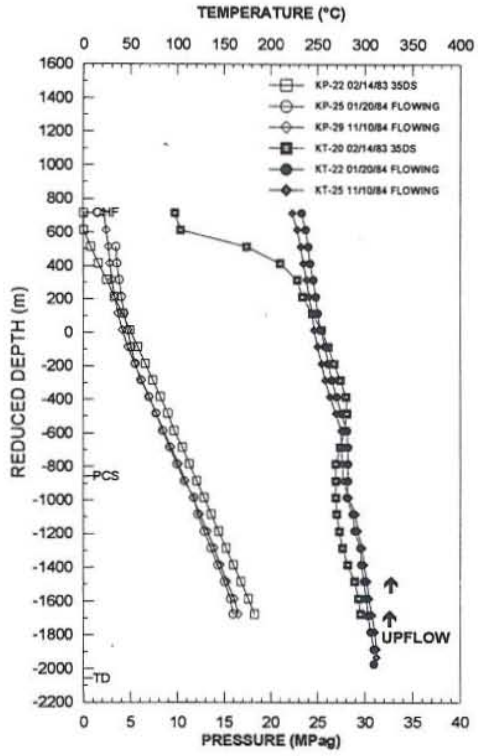


FIGURE 71: Temperature and pressure profiles in well PN-26 showing production at the bottom

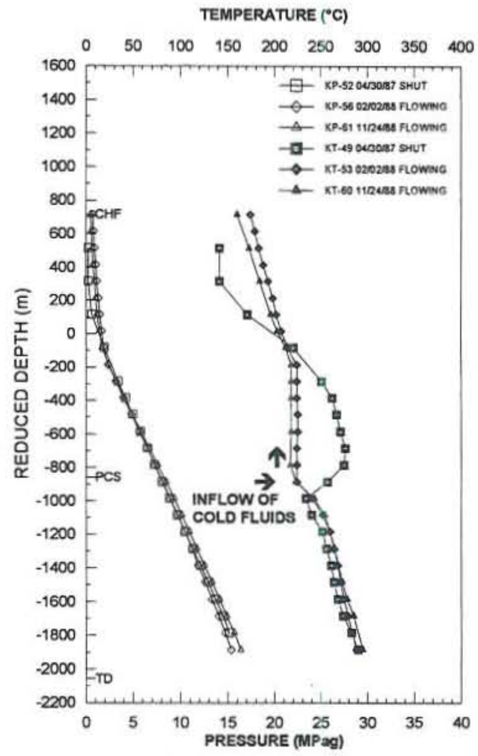


FIGURE 72: Temperature and pressure profiles in well PN-26 showing an inflow of cold fluids below the casing shoe

reinjection well PN-1RD was still connected the system. The feed temperature at this interval was about 258°C. In 1990, when PN-1RD most of the brines were reinjected into Malaunay and Ticala wells, the bottom zone dominated the discharge with a maximum temperature of 310°C. Note that the flowing pressure measured in conjunction with this temperature survey was significantly lower than that when there was the downflow and when the reinjection return to this well was higher. Figure 74 best demonstrates the recovery in the well temperatures.

Well PN-19D also exhibited changes in its flowing profiles in response to changes in the reinjection strategy. Before the utilization of the Ticala and the Malaunay wells, the flowing temperature profile indicates a downflow of 235°C emanating from 680 m and exiting at -1800 m. The well also recovered its temperature in 1990 with the utilization of the above sectors with maximum temperature of 300°C (Figure 75).

The decommissioning of some Puhagan reinjection wells from the system revealed significant temperature recovery as shown in Figure 76. Temperatures measured in 1990 nearly approach the 1991 data before the utilization of the well to the system. PN-9RD temperatures in 1989 followed the boiling point condition at the hole's upper section while the temperatures at the bottom approximated 300°C. PN-6RD and PN-7RD exhibit the same pattern although the recovery seems to be slow, especially at the bottom. Wellbore simulations suggest the possible utilization of these production wells in the future. Their priority is, however, not higher because of the significant amount of brine in their discharges.

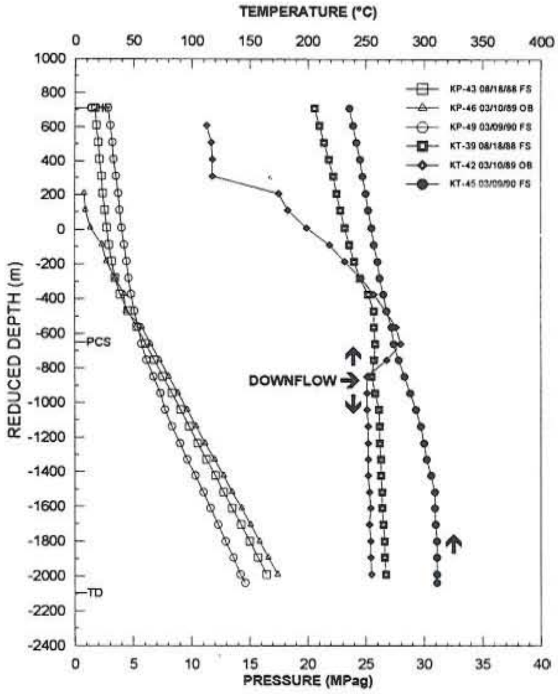


FIGURE 73: Well PN-29D, temperature and pressure profiles showing cold downflow at -800 m

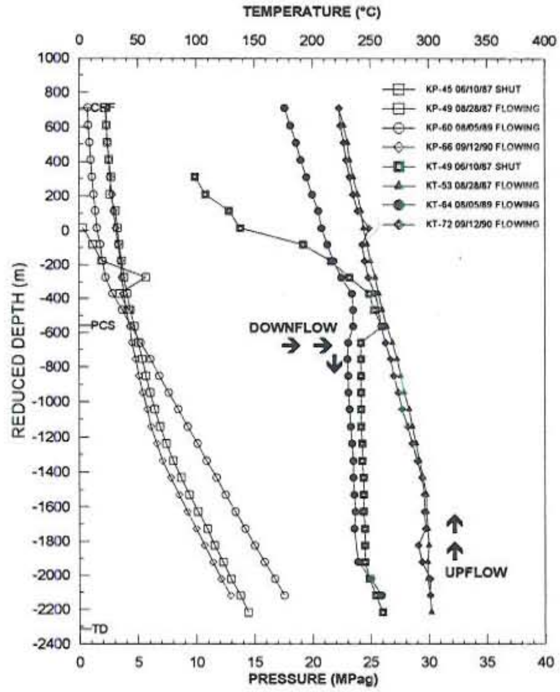


FIGURE 75: Well PN-19D, temperature and pressure profiles showing cold inflow below casing shoe and production

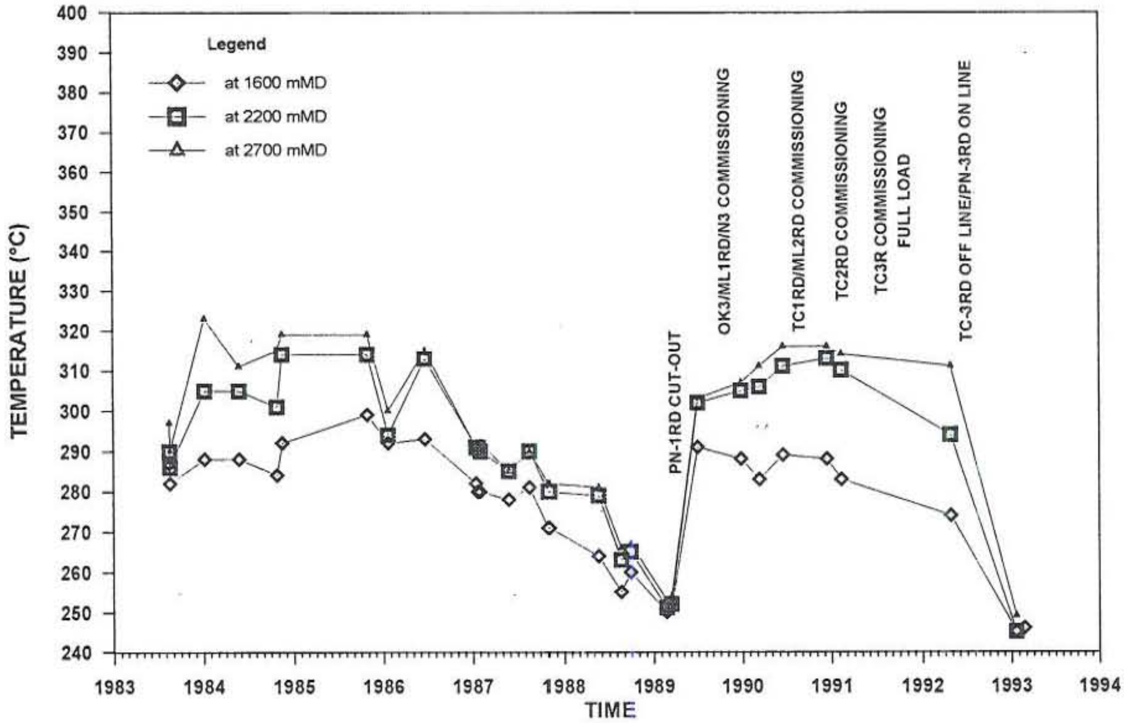


FIGURE 74: Temperature trends in well PN-29D at selected depths

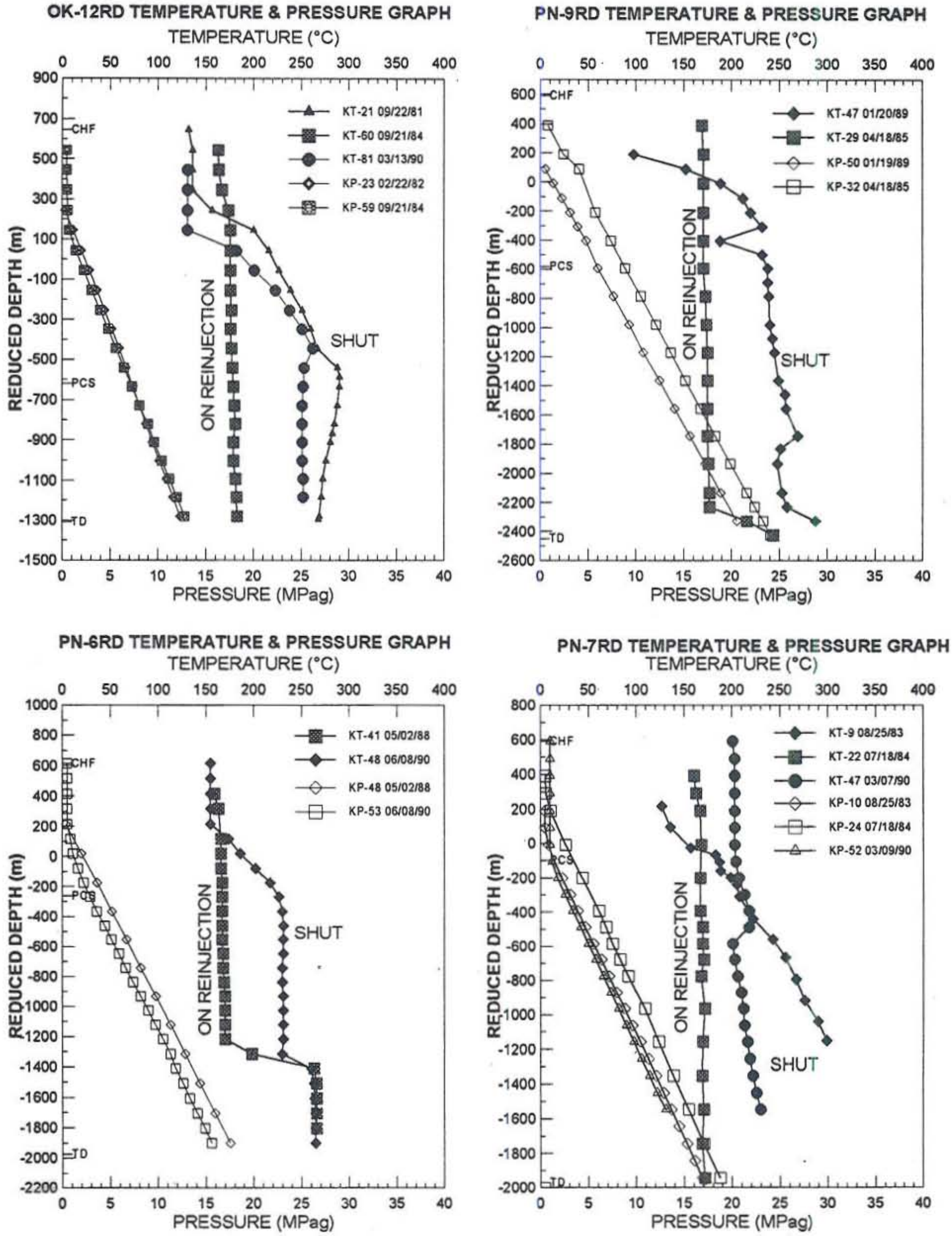


FIGURE 76: Temperature recovery in previously utilized reinjection wells

5.8 Changes in bore output

The changes in the performance of the production wells demonstrate the impact of the current management methods as compared to the previous well utilization strategies. The initial response of the field to exploitation had been marked by increase in enthalpies of the production wells as a result pressure drawdown. However, wells that have been affected by reinjection returns due to the utilization of a particular reinjection well exhibit decline in enthalpy although the mass flow discharges remain unchanged.

In the Central Puhagan area, two wells, OK-7 and PN-14, have shown some decline in enthalpy without a significant initial change in the mass flow. This implies an increase in relative contribution of the cooler fluid from the production zone affected by reinjection returns. The increase in pressure gradient between the Puhagan reinjection area and the production area has likely increased the cooler reinjection returns to the production area. The chloride data of these two wells show significant proportion (up to 90%) of the discharge to be reinjection fluid returns. In PN-28, the mass flow significantly dropped by 13 kg/s (33.2%) but its enthalpy remained unchanged. The fluid condition here is such that boiling has not taken place in this sector to induce an increase in enthalpy as observed in the north and northeastern production wells. Well PN-26 stopped producing when it was unable to sustain a commercial wellhead pressure of 0.7 MPa, e.g., after 5 years in operation in the middle of 1988. Its enthalpy has gone down to 900 kJ/kg from 1350 kJ/kg. This well has not recovered yet even after the absorption of the bulk of reinjection load by the Ticala and Malaunay reinjection wells. The output trends in Figure 77 indicate that the output of these wells in the Central Puhagan will continue to deteriorate as shown by the continuous drop in the enthalpy from 1992 through 1993.

Well PN-15D in the northeastern production sector has shown an increase in the discharge enthalpy with approximately 438 kJ/kg. This was followed by a drop in the mass flow associated with the general pressure drawdown in the reservoir particularly in the upper zone where majority of the production is coming from. PN-17D appears to be on the verge of collapsing also with its production as shown by its regular cycling of an "on-and-off" production to the system. PN-21D has not attained any improvement after a recent perforation job in its 9⅝" casing and it is likely that the output will also deteriorate in the future.

PN-29D is the only well in the southern sector of Puhagan that was tested on a regular basis. PN-30D and PN-31D have been on line most of the time to the power plant as control wells and could not be taken-off line for testing. These wells absorb the increases and drops in the load of the power plant. The enthalpy, massflow and steam output of PN-29D increased significantly during the initial exploitation period as shown in Figure 78. However, there was a decline in the same parameters after 6 months of production due to the effects of reinjection returns. With the shifting of reinjection to Ticala and Malaunay in the second half of 1989, the well gradually recovered its steam output, enthalpy and massflow. Its enthalpy continued to increase from 1200 kJ/kg in 1990 to 1600 kJ/kg in the middle of 1991. It started to drop with the commissioning of TC-3R during the same period. TC-3R is a shallow injection well and known to be communicating with the production sector through the Ticala fault in the shallow portion of Puhagan. It is very permeable and can accept more than 200 kg/s of reinjected water. It is designed as a big hole with 9⅝" liner in the open hole. The latest data on PN-29D indicate that well output fluctuates from 40 to 60 kg/s mass flow depending on whether TC-3R is on line or not. Recent data also indicates that PN-29D is affected by injection from PN-3RD. PN-31D and PN-24D remain discharging with enthalpy of 1600-1800 kJ/kg. This measurement indicates that reinjection returns have not significantly affected their performance.

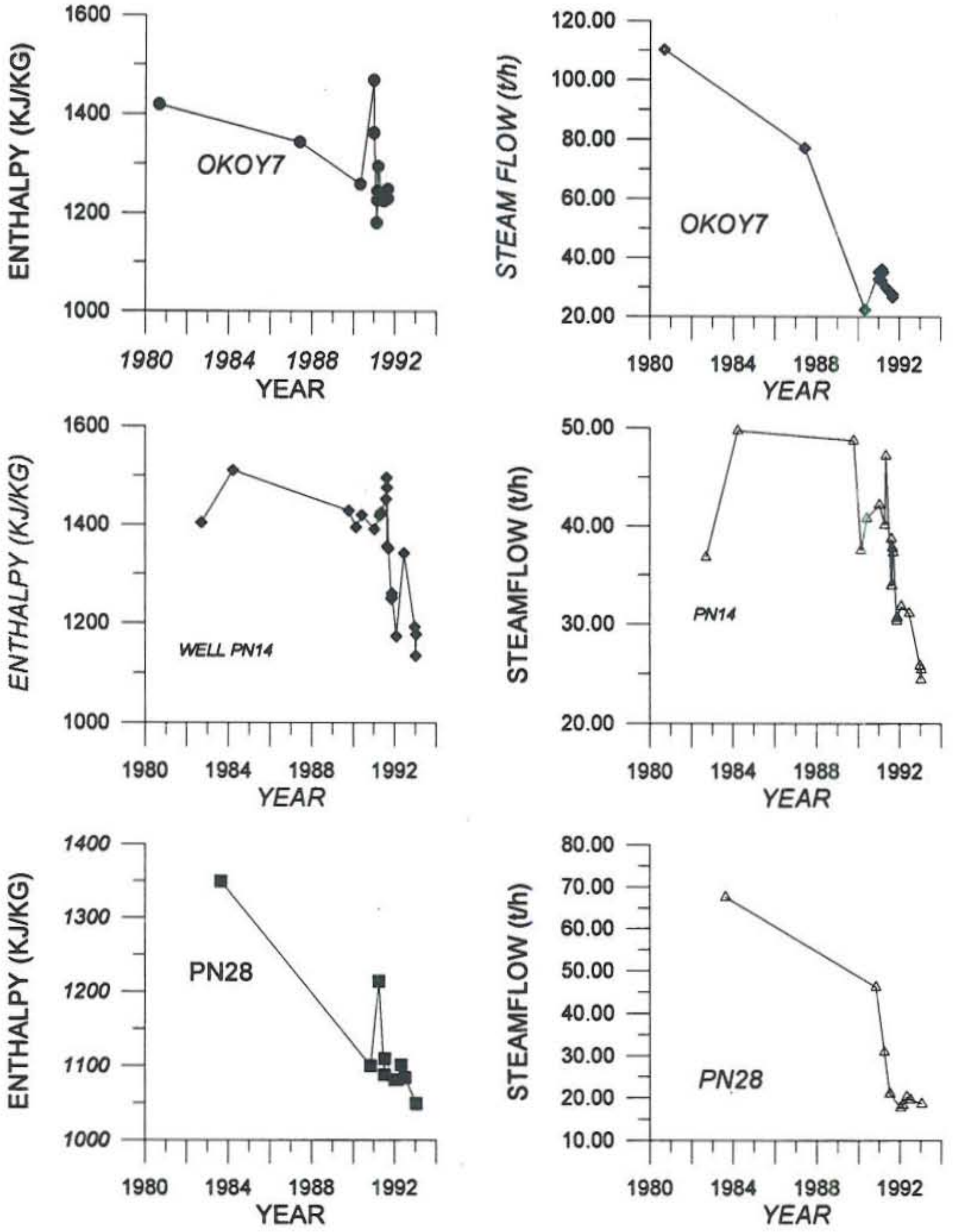


FIGURE 77: Output trends of different wells, central Puhagan sector of Palinpinon

PN-17D exemplifies the well that has not shown significant improvement in output even though the major reinjection sector had been moved away. Its output follows a declining trend and currently is showing cycling in its output. It is likely that this well will similarly cease producing to the system.

On the other hand, well OK-10D in the southeastern production sector appears to have benefitted from the utilization of TC-2RD as maintenance of its pH at desirable level (>6) prolonged its production period to the system (Figure 79). This well was always cut-off from the system whenever its pH went down to 4.5. Its output also increased significantly in 1991 when reinjection well TC-2RD was cut-in to the system. Well TC-2RD had intersected the Odlumon fault that was also intersected by OK-10D at the top zone. Through this fault, the reinjection fluids find its way to the production sector diluting the low pH fluid of OK-10D.

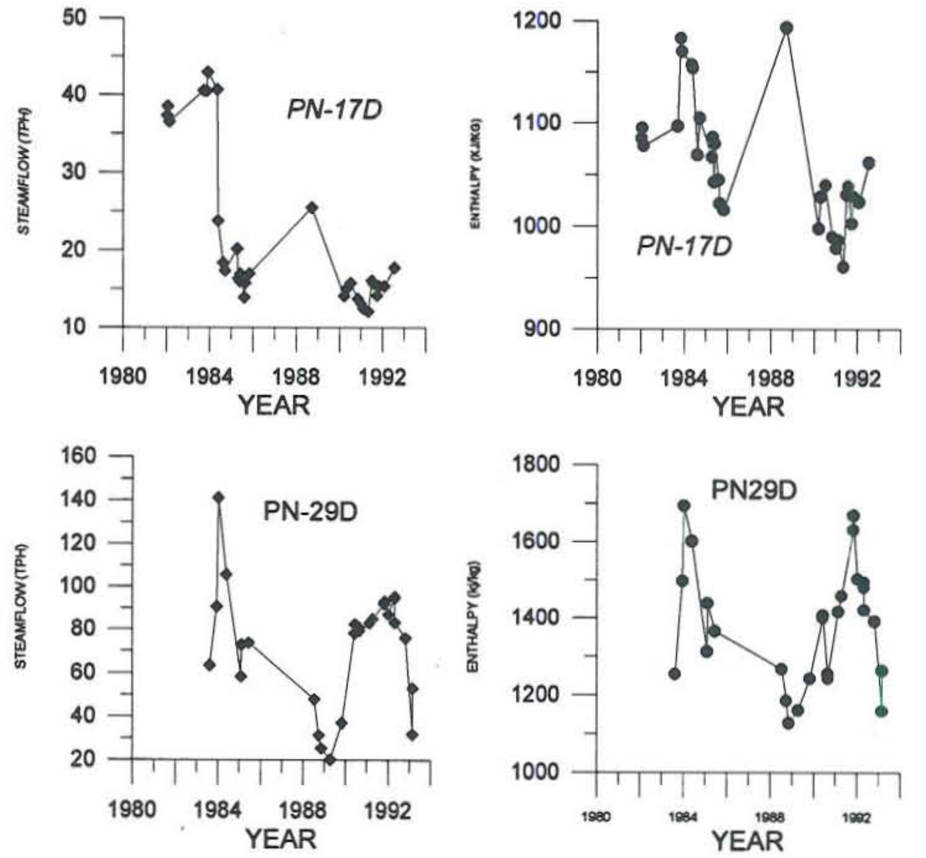


FIGURE 78: Output trends of wells PN-29D and PN-17D

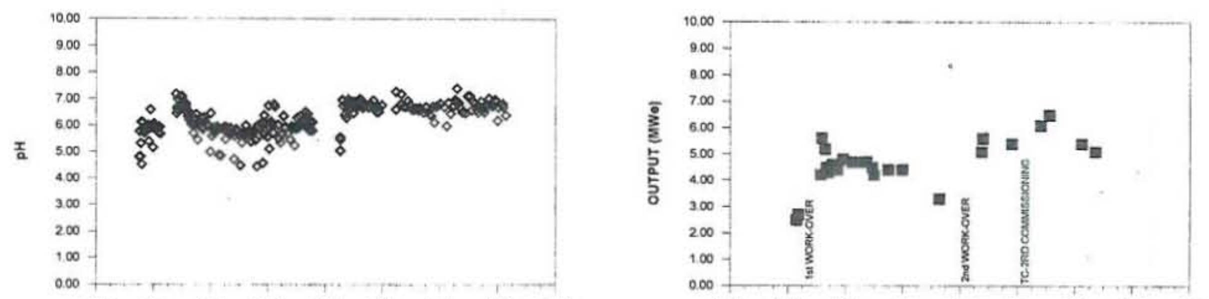


FIGURE 79: Output trend of well OK-10D showing increase in pH
and output when well TC-2RD was used as an injection well

5.9 Field output response

The overall impact of these brines returning to the production sector is a continuing reduction of the field capacity from 1500 tons/hour in the middle of 1984 to current level of approximately 96 tons/hour (Figure 80). Recent estimates from the station plant meter indicate that the field capacity could still be within 106 MW_e. However, this level still implies a significant decline from the beginning.

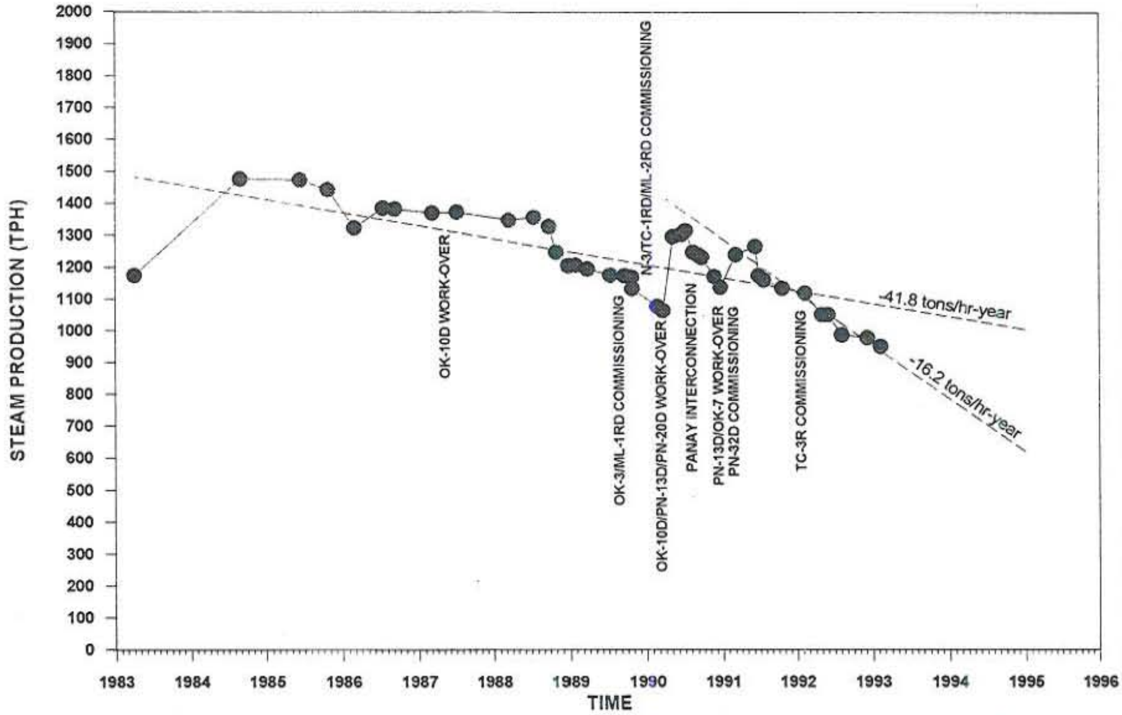


FIGURE 80: Total field output trend of Palinpinon I showing possible decline rates

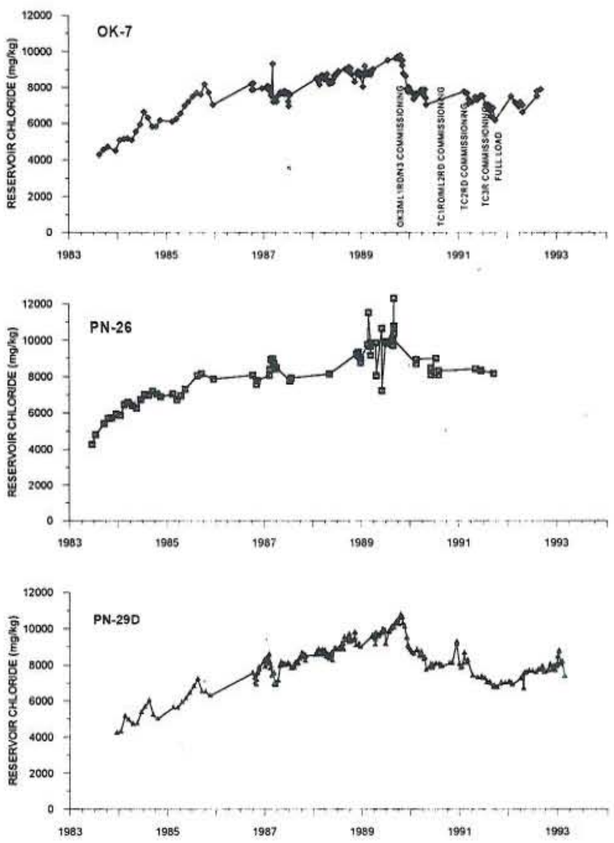


FIGURE 81: Changes in the reservoir's chloride levels with shift in reinjection strategy

It is apparent from the results of the above monitoring of Palinpinon that the utilization of Malaunay and Ticala wells to handle the bulk of the brines had not resulted in a sustainable recovery in temperatures and enthalpy of the Puhagan production wells. The expected increase in the average field enthalpy did happen when the enthalpy increased from about 1380 kJ/kg to about 1580 kJ/kg in 1991. This did not result in a significant increase in the steam production because moving the fluids farther away from Puhagan resulted in more pressure drawdown to the reservoir - causing a reduction in the wells' mass flows and subsequent reduction in steam output of individual wells. Even the chloride levels in most of the production wells showed only a transient or short term decline in the reservoir fluid as they stabilized after 6 months of utilizing these reinjection wells (Figure 81). The continuous return of the brines to the Puhagan sector through the faults especially through the Tickle fault that runs to the reinjection and production sectors (also intersected by well CT-3R) will continue to threaten the life of the field unless an appropriate strategy is implemented immediately.

5.10 Conclusions

The results of the above discussions indicate that the key to the temperature recovery of some production wells and sustenance of the field output is to reduce the amount of fluids returning to the production sector. The field monitoring also shows that reinjected brines continue to affect the Puhagan reinjection wells even with the shifting of reinjection sector because the brines still return to the production sector. The current belief is that the only way to reduce the reinjection fluids is through the production of higher enthalpy fluids and/or drilling farther away beyond the Ticala and Malaunay. One of the strategies under consideration is to connect the Lagunao sector to tap the identified steam for at least 20 MW_e. This output can displace approximately 84 kg/s of brine from the central Puhagan wells thereby significantly reducing the amount of reinjection fluids. The option of reinjecting farther away to the valley through hot and/or cold injection will also be pursued in the future.

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