

PALINPINON 1 GEOTHERMAL PRODUCTION FIELD TWENTY YEARS EXPERIENCE

Vicente D. Omandam, Jr.

PNOC Energy Development Corporation, Southern Negros Geothermal Field, Philippines

ABSTRACT

Commercial exploitation of Palinpinon I Production Field started in 1983. Palinpinon I is located in the Southern Negros Geothermal Field in the island of Negros, Philippines and managed by the Philippine National Oil Company – Energy Development Corporation. It supplies the steam that drives the 3 x 37.5 MWe turbine generator units of the state owned National Power Corporation.

During its twenty years of exploitation, the Palinpinon I Field has been continuously assessed, and problems observed are carefully studied. Problems encountered on well utilization to sustain the steam capability are discussed. Chemical, pressure, temperature, and flow monitoring had been proven to be important factors in optimizing the performance of the Palinpinon I Field.

The Zero Disposal System, which is integrated into the Fluid Collection and Recycling System, is also cited in this report. This method of geothermal fluid recycling and environmental protection is an improvement of early brine disposal practices.

1.0 BRIEF HISTORY OF PALINPINON I PRODUCTION FIELD

The Palinpinon I Geothermal Field is located in Palinpinon, Valencia in the Island of Negros, Republic of the Philippines. Exploitation is concentrated at Puhagan Valley with an area of 6.5 square kilometers (Figure 1). Exploration was started by COMVOL and the New Zealand government in 1973 and was turned over to the National Power Corporation (NPC) in 1975. In 1976, the exploration was turned over to the Energy Development Corporation (EDC), a subsidiary of the Philippine National Oil Company (PNOC). Technical assistance was

provided by the New Zealand Government in coordination with Kingston Reynolds Thom and Allardice Limited (KRTA). By 1979, evaluation of exploration results indicated the feasibility of establishing a geothermal power plant in the area.

In July 1980, a formal commitment was made to develop the Southern Negros Geothermal Field at Puhagan Valley and construct Palinpinon I, a 3 x 37.5 MWe power station and Fluid Collection and Recycling System (FCRS) for commissioning in 1983. The FCRS was funded by a loan from the Overseas Economic Cooperation Fund (90th). Palinpinon I forms the first phase of the development of the Palinpinon Production Field. This was followed later by Palinpinon II (4 x 20 MWe) in December 1993.

The FCRS and the 112.5 MWe Power Plant were commissioned in June 1983. PNOC-EDC supplies geothermal steam to the Palinpinon I Geothermal Power Plant (PGPPI) of the state owned National Power Corporation (NPC). Since then, four production wells and seven injection wells were added.

2.0 OVERVIEW OF THE PAL I FCRS

The whole area is characterized by difficult terrain in heavily forested mountains with elevations ranging from 600-1200 meters above sea level. Because of this constraint, a policy of deviated drilling was adopted by PNOC-EDC for both production and injection wells. The production and injection wells were drilled on multi-well pads. Single flash separation is done at the centralized separator station where the two-phase fluid is separated into water and steam at a pressure of 5.8 kscg. Steam is supplied to the power plant at 5.0-5.5 kscg depending on the steam demand. The separator pressure, main header pressure, and separator levels are automatically controlled using a

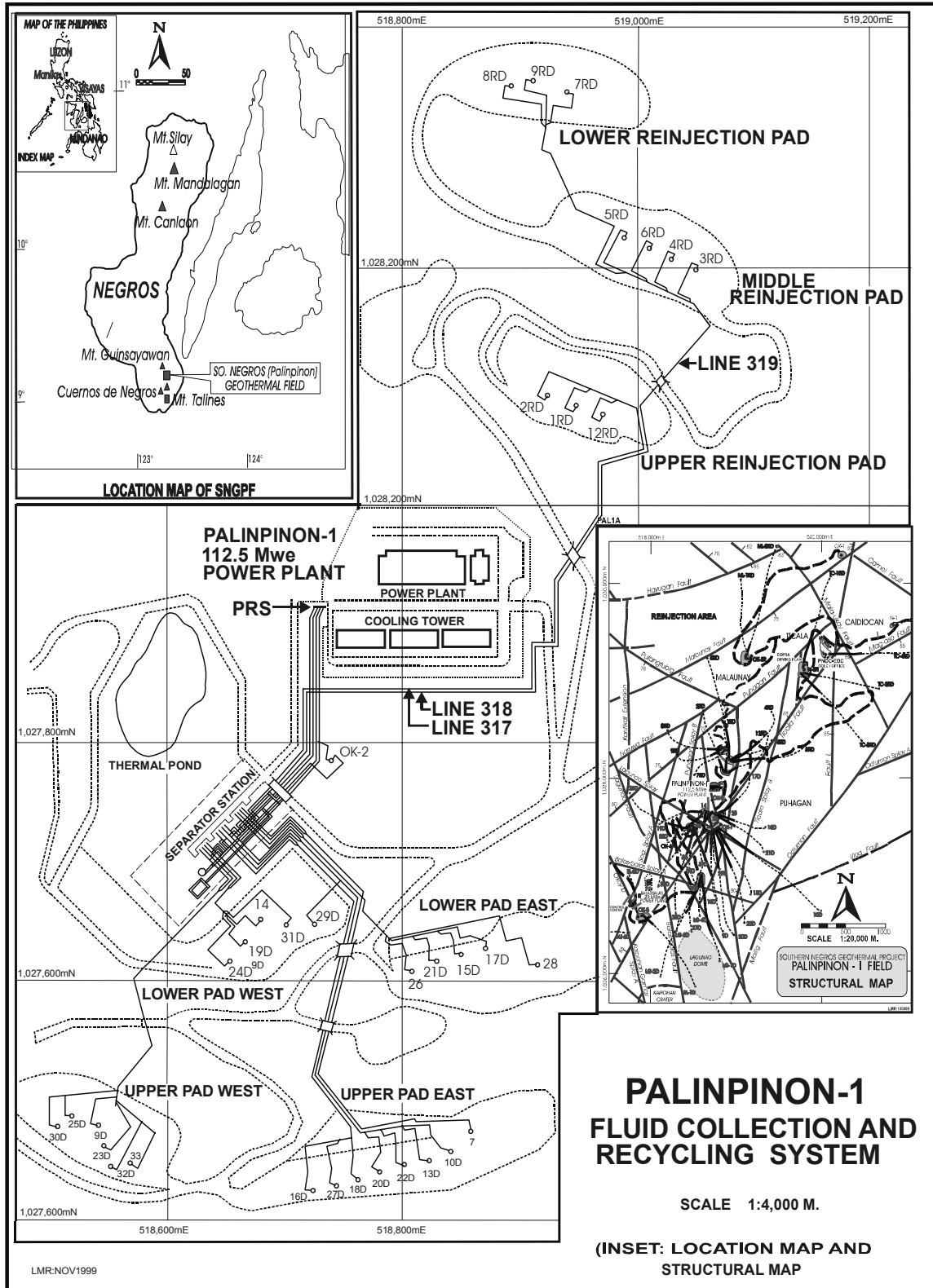


Figure 1. Palinpinon-1 fluid collection and recycling system.

distributed control system. Except for the motorized valves, which are used to trim excess steam, the opening and closing of wellhead valves are done manually.

3.0 PLANT LOADING

The 112.5 MWe Palinpinon I Geothermal Power Plant (PGPPI) was originally planned to supply power to several mining firms and residential consumers in Negros Island. When the plant was commissioned in 1983, the mining firms incidentally closed and several transmission towers were also toppled. As a result, the plant load from 1983 to 1989 was limited to the power requirements of the small factories, sugar centrals and households within Negros Island. Full load was only attained in October 1990 when the neighboring island of Panay was interconnected to the Negros grid by a submarine cable. On January 26, 1993, the island of Cebu was also interconnected by submarine cable to Negros Island. The Cebu-Negros-Panay interconnection resulted in the optimum loading of PGPPI up to the present. As of last year (2002), the peak load was at 98.26 and average plant load was at 75.85 MWe.

4.0 RESERVOIR PERFORMANCE

Since the start of the commercial operation of PGPPI in 1983, the P1PF reservoir pressure had dropped by ~5.5 Mpag in 1994 (Amistoso, et. al., 2000) and further dropped to 5.2 Mpag in the middle of 2002 (Amistoso, et. al., 2002). The pressure drawdown and breakthrough of insufficiently heated injected brine to the production sector caused the cooling of feed zones in affected wells. As early as 1984, injection returns had already been detected in the Puhagan production area and observed temperature declines ranged from 5°C to 20°C. The injection line chloride, which is indicative of injection returns, likewise increased to about 11400 mg/kg compared to the initial exploitation period of about 6000 mg/kg. The worst effect was in wells PN26 and OK-7, both in the Central Puhagan area, where the main production zones were severely cooled. These two wells, became unproductive in 1984 and 1990 respectively, and has not recovered to date. To prevent further cooling of some production wells due to injection returns, a study to shift injection away from Puhagan sector was made in 1985.

5.0 STRATEGIES TO SUSTAIN STEAM CAPABILITY

5.1 Injection Strategy

The shift in brine injection was realized in October 1989 when wastewater injection was shifted to the Ticala/Malaunay sector (Figure 1). The change in injection strategy initially reduced the field injection returns into the Puhagan sector from 75% to 45%, which consequently resulted to an increase in field enthalpy and improvement in steam capability. In July 1997, injection to Puhagan was stopped when PN5RD was shut. An increase in enthalpy was observed but the total steam availability continued to decline. A plot of the enthalpy and injection rates is shown in Figure 2.

By the year 2000 up to 2002, Puhagan injection was restored but at a controlled rate of 50 kg/s (15%) and the balance of the brine which was about 300 kg/s was injected to the Ticala/Malaunay sector. The injection strategy has so far maintained the supply above the 75% off-take. Likewise, the field enthalpy did not change significantly from 2001 to 2002. Steam supply, however, slightly declined as a result of heightened pressure drawdown and suspected cool fluid inflows. A summary of the injection strategy is shown in Table 1.

5.2 Workover / Acidizing and Drilling Additional Wells

The steam supply for Pal I was augmented when PN32D, PN33, LG3D and LG4D were drilled and commissioned from April 1991 to October 1996. The outputs of these wells were further improved by a few megawatts after acidizing.

Well OK-2, which was originally a condensate well for the Pal I power plant, had an initial output of 2.3 MWe. As the field developed a steam cap as a result of full load operation and reduced injection return, the well output improved to 6.6 MWe. The well was then utilized as a production well since October 1991 without any indication of output decline.

A similar case also happened at PN25D that was a non-commercial well after completion in January 1983. After several discharge attempts, the well started producing at 1.2 MWe on October 1, 1992.

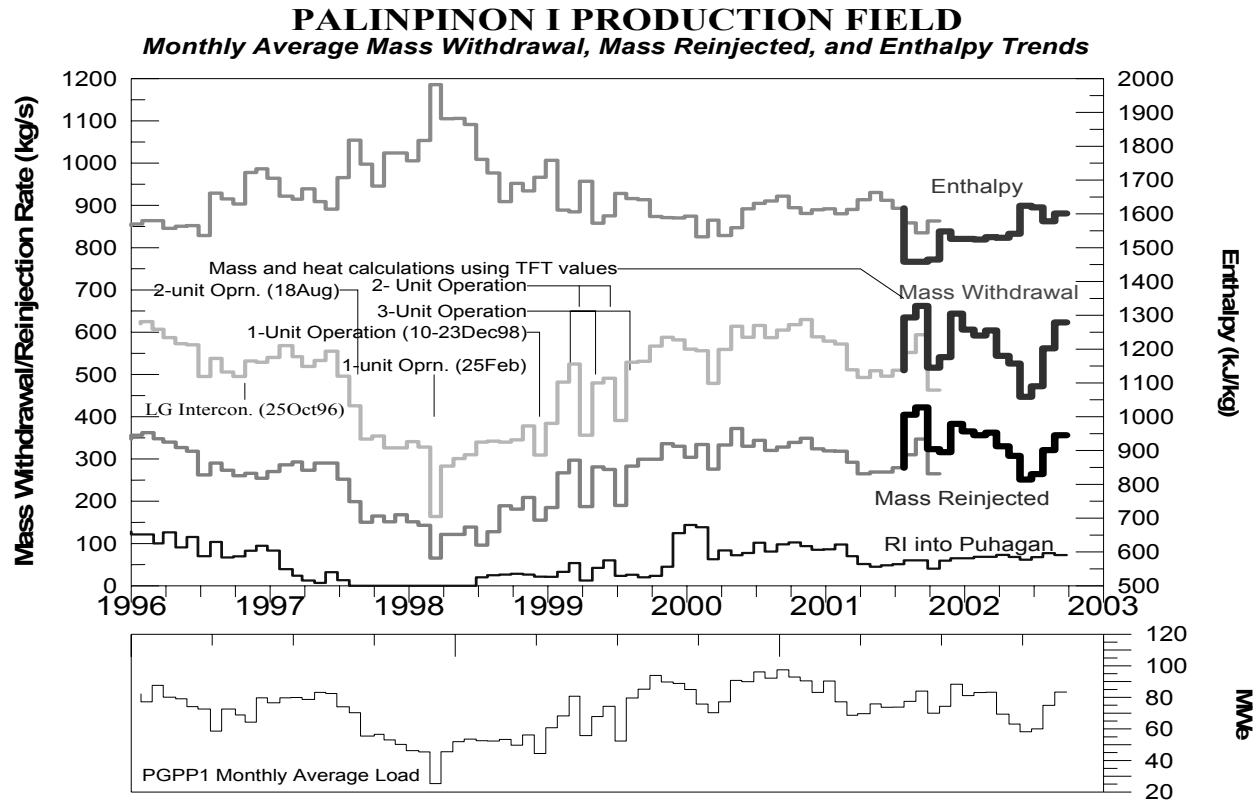


Figure 2. Steam availability and enthalpy trends.

The output improved to 2.8 MWe after perforation and acidizing in May 1995.

5.3 Two-phase Line Interconnection

The Pal I FCRS was originally constructed as a multi-pad system wherein production wells were grouped per production well pad. The wells were then connected to a two-phase header that fed to a dedicated separator vessel. With the constant changes in production well output, some vessels became under-loaded while others were overloaded. This became an operational constraint particularly during vessel maintenance, wherein the wells connected were also shut down.

To allow maintenance flexibility and to ensure full load steam capability at any time, the two-phase headers were interconnected near the separator station. With the two-phase line interconnection, the production wells can be diverted to any available separator vessel and steam supply will not be affected by vessel maintenance.

6.0 OPERATING EXPERIENCE

Pal I, being the main source of power for the Negros and Panay Islands was operated as a variable load station. To cope with the high load fluctuation, three two-phase motorized valves were installed so that production wells can be throttled remotely to cope with the steam demand. In 1991 and 1997 two more two-phase motorized valves were installed to cope with the plant load fluctuation and reduce steam wastage during periods with low load.

The full load operation of Pal I started on October 17, 1990 when Panay Island was connected to the grid. But prior to that, several options to sustain steam capability were already in place. These were the transfer of the brine injection, two-phase interconnection, descaling and commissioning of additional production wells. However, brine injection strategy still needs some fine tuning at that time because mass breakthrough of injection fluids to the production sector was still observed. Likewise, injected fluids at one well (TC2RD) also helped suppressed the acid-sulphate fluid component in

Table 1. Summary of injection strategy.

Injection Wells	Date	Load MWe	Injection Strategy	Remarks
OK12RD	May 1983 to Nov 1984	45.6	A. Easterly	Strategy, A, B, C, and D were ineffective. These injection wells had a massive injection return to PN26, PN28, PN19D, PN29D, OK7. The rapid communication does not allow effective fluid reheating (fluid transit time was less than 1 day to two weeks).
PN8RD PN9RD	Dec 1984 to Oct 1986	44.2	B. Westerly	
PN1RD PN2RD PN5RD	Nov 1985 to Jan 1986	46.5	C. Central	
PN2RD PN3RD PN4RD PN5RD	Jul 1986 to Oct 1989	71.6	D. Central Easterly	
OK-3R ML1RD ML2RD N-3/TC1RD (1990) TC2RD TC3RD	Oct 1989 to Jan 1993		E. Ticala-Malaunay Sector	These wells reduced the injection fluid returns from approx 890K tons. The injection chloride decreased from 11400 ppm to 8400 ppm in 1990. The percentage decline in injection fluid return is 10% to 45%. This strategy improved several production wells (PN29D, PN19D, PN16D, PN23D, OK10D, PN13D)
OK3 ML1RD ML2RD N-3 TC2RD TC3RD TC4RD PN5RD PN2RD PN3RD	1993 to JUL 1997	107.53	F. Ticala-Malaunay Sector	Injection fluids were observed to continue to intrude back to the production sector at high brine load. TC3r/N3 had stroking connection with some production wells thru the Ticala Fault.
ML1RD ML2RD TC2RD TC3RD TC4RD OK3R	July 1997 present Feb 1999	98.02	G. Ticala-Malaunay Sector	Injection to Puhagan was eliminated. The immediate response was the fieldwide increases in enthalpy. P1PF apparently attained equilibrium in 1998. No thermal degradation was observed in 1998.
ML1RD ML2RD TC2RD TC3RD TC4RD OK3R PN5RD	Feb 1999 to Present	98.26	H. Ticala-Malaunay Sector	PN5RD was put back on line to relieve the very high brine load at TC3RD. Field enthalpy increased from 1536 to 1615 kg/j in 2000. Average field enthalpy did not change significantly in 2001 to 2002. Steam supply slightly decline as a result of heightened pressure drawdown and suspected cool fluid inflows.

some wells, particularly those that had intersected the Odlumon fault. As a result, the pH of acidic wells PN20D, PN22D & OK10D improved and this became usable. These observations confirmed that steam supply was largely sensitive to the brine injection strategy. Due to these observations, the brine injection strategy was periodically reviewed and updated. A summary is presented in Table 1.

During its twenty years of operations, Pal I FCRS had several peculiar experiences. These are briefly discussed in the sections that follow.

6.1 Silica Deposition in Injection Lines

After four (4) years of operation, silica deposits have accumulated in some sections of the 12"Ø and 24"Ø injection pipelines. The straight horizontal section had a silica thickness of 152-305 mm, while scale thickness at the sloping sections varied from 3-76 mm. Descaling was done in 1987 in about 1540 meters of pipeline for a period of seven (7) months and with a cost of P773,000 (P502/m). This also involved generation losses due to load shedding at PGPI upon the request of PNOC-EDC. This

prompted PNOC-EDC to construct redundant injection lines to avoid load shedding in future descaling activities. Likewise, installation of access spools was also done as a provision for future descaling. In July 1999, sections of pipeline 313 and part of line 317 were again descaled as there were bottle necks in certain sections. Silica scale thickness varied from 240 mm at horizontal elbows and 10mm at some sections. Descaling of line 317 was continued in March to April 2000 up to the Upper Reinjection Pad. Total descaled length was about 441.96 m at a cost of P844,207 (P1910.14 per m).

Silica deposition was minimized in most areas of the injection lines by maintaining high fluid velocity and brine silica saturation index above 1.0.

6.2 Deposition in Two-Phase Lines

The deposition rates in the two-phase cross-country lines were practically very low. No major descaling activity was done in these pipelines for the past twenty (20) years of utilization. Mechanical descaling was done only in the wellhead branch lines and discharge lines to the silencer in 1996-1997. However, an unusually high rate of deposition (thickness 50-70mm) at V101/V102 two-phase line bifurcator was discovered in May 17, 2002 when water lines were fully blocked with flaked deposits from the two-phase line. The deposits were found to be silica, corrosion products, and some formation cuttings. Site staff suspected that this was due to the turbulent flow and mixing of dry steam with two-phase fluid that was confined to that section only. Descaling and pipeline modification is scheduled by 2003 in order to eliminate the high deposition rate in that section.

6.3 Damaged Pipe Supports

Several pipe supports of the FCRS were found damaged by corrosion in 2001 or about 18 years after commissioning. The structural supports were damaged by uniform corrosion. Jacking of pipelines and manifolds by corrosion products under base plates was also observed. The problem progressed to stress levels sufficient to fracture anchor bolts on some supports. That was because, these pipe supports were exposed to steam traps and vents nearby.

Repair of these supports have been started in 2002 and completion is expected in 2003. All

repairs were done with the affected pipelines being utilized. Thus, no load shedding was experienced.

6.4 Steam Capability Assessment

When full load operation of Pal I started, practically all wells were utilized. Assessment of well outputs, which were frequently changing, became a concern. Not all wells can be isolated for testing. The primary concern at that time was an effective daily total output trend monitoring. This was very important in order to have a trend of steam availability and effectively study options to sustain the steam supply. Likewise, it would help monitor the steam conversion efficiency of the turbines.

In December 1990, a simple monitoring technique was developed to monitor the total steam flow using the plant as a gauge. The technique considers the Field Steam (total steam flow) as a summation of the following: Field Steam = Plant steam + Vent steam (Catigtig et al., 1993). The vent steam was calculated based on a curve fit between valve opening and equivalent steam blow off. The plant steam is the calculated steam consumption of the turbine calculated based on the actual load, steam rate, no load steam and steam used to drive the steam gas ejector. The steam consumption was corrected for the condenser vacuum changes. The method was then useful for monitoring steam capability, changes at that time. The disadvantage of that method of steam flow estimation was that the plant steam estimate was affected by a lot of variables. Such variables were, actual steam rate, condenser vacuum and turbine efficiency. Likewise, the vent steam estimate was less accurate at big valve openings.

With the improvement in steam flow metering at the steam lines and with the help of tracer flow measurements, a more direct technique of total steam and water flow measurements was developed and approved for use. This technique would be independent of turbine performance. The technique would involve measuring the steam flow by orifice plate and the water flow measured either by tracer or orifice plate at maximum plant load. All wells will be utilized at fully bore conditions. This ensures that the vent steam is at minimum. The summation of total steam flow would still be:

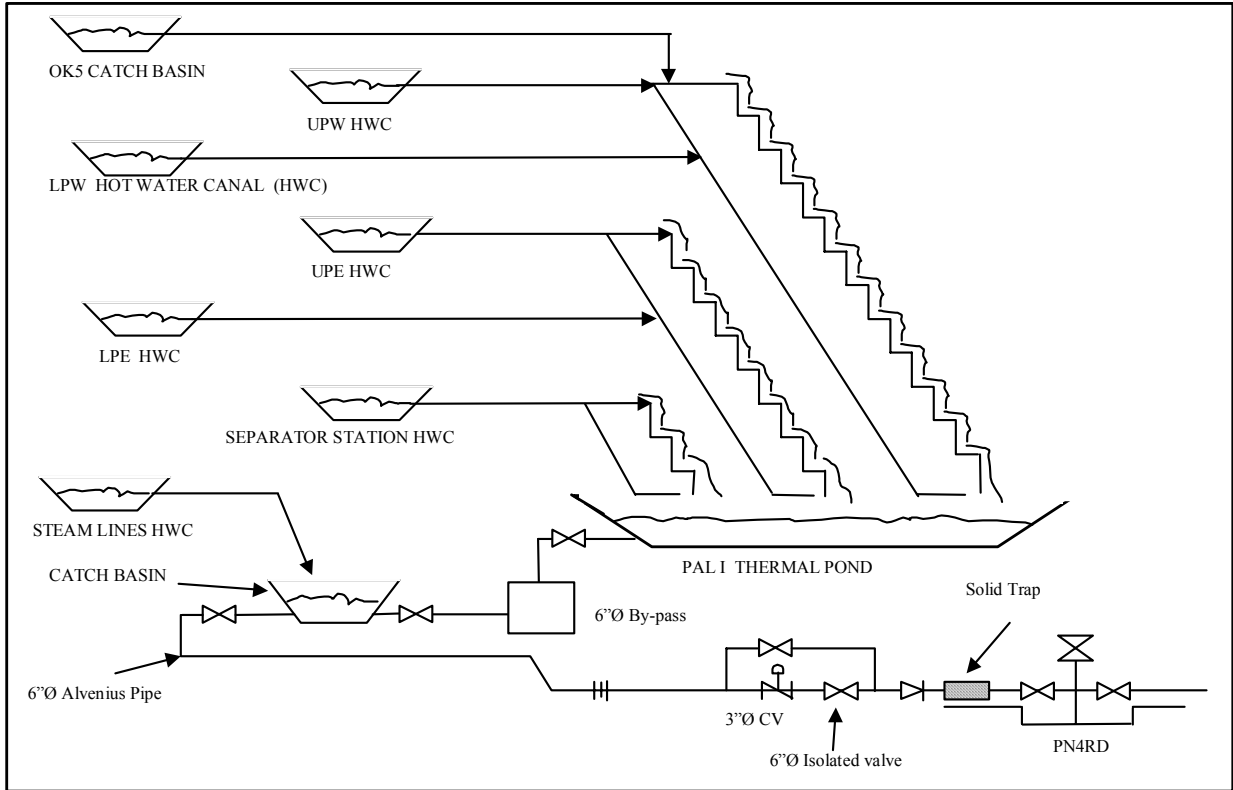


Figure 3. PAL I Zero Disposal System

$$\begin{aligned} \text{Field Steam} &= \text{Plant Steam} + \text{Vent Steam} \\ &\quad \text{(at minimum opening)} \\ &= \text{Steam Orifice Plate Measurements} \\ &\quad + \text{Vent Steam} \end{aligned}$$

Field Steam represents the total steam available from Pal I Production Field

$$\begin{aligned} \text{Total Water Flow} &= \text{Line 317} + \text{Line 318} \\ &\quad \text{Water Flow} \end{aligned}$$

Using the total steam flow data above and the measured water flow, the field enthalpy can be easily calculated. A daily spot check can also be done during peak load (minimum vent steam) to monitor changes in the total steam flow and steam conversion efficiency.

All the data obtained from the steam and water flow measurements when correlated with the chloride monitoring, well chemical data, well output, downhole temperatures, downhole pressure, and geological data, can be a very effective tool in assessing well utilization programs and formulating strategies in managing the field.

7.0 ZERO DISPOSAL SYSTEM (ZDS)

Since the start of Pal I operation, effluents were limited within the air and water quality standards as required by Department of Environment and Natural Resources Administration Order (DAO) No.14 and 34, respectively. However, in 1990, DAO 35 effectively revised the regulations such that no untreated or inadequately treated effluents will be discharged to the water system. This practically requires that all geothermal effluents that are beyond the water quality standards should be contained and injected.

The new regulation prompted SNGPF to install a Zero Disposal System (ZDS) at Pal-I FCRS that was commissioned on July 21, 1998. The system practically collects all discharges from the wellhead, pipe vents, steam traps, silencer and drain. A network of canals conveys the effluents including cooling tower blowdown and separated water from OK5 power plant to the thermal pond and from there, a pipeline collects the cold brine and injects it to PN4RD at a rate of 17 kg/s to 24 kg/s. A schematic diagram is shown in Figure 3.

The ZDS has been operational for the past four (4) years. During the said period, SNGPF managed full compliance to the DENR requirement of 0.75 ppm boron limit at the impact station. So far, no detrimental effect to the reservoir was observed. The alvenius pipelines encountered some pitting corrosion in some portions but the corrosion rate is manageable.

8.0 CONCLUSIONS

The Palinpinon I Production Field has made a substantial contribution to meeting the country's power requirement for the past 20 years. The key to the successful 20 years of operation was intensive monitoring of chemical and physical changes in the reservoir which was the basis in formulating and implementing effective reservoir management strategies.

ACKNOWLEDGEMENT

The author would like to thank the management and staff of the Philippine National Oil Company Energy Development Corporation for their support to the preparation of this report. My sincere thanks to the Production, Reservoir, & Geoscientific Technical Staff of SNGPF, and to all who have contributed to the realization of this report in one way or another.

REFERENCES

- Amistoso, A.E., Orizonte, R.G., and Aqui, A.R. (1999). Reservoir management during 15 years of exploration: Southern Negros Geothermal Production Field. *Proceedings of the World Geothermal Congress 2000, Japan*.
- Amistoso, A.E., Orizonte, R.G., and Aqui, A.R. (2002). RRMD – SNGPF Reservoir Engineering Report (1st half of year 2002). *PNOC-EDC Internal Report*.
- Catigtig, D.C., Jordan, O.T., Seastres, J.S., and Jalando-on, R.G. (1993). Palinpinon I geothermal production field ten year experience (Problems and Solutions). *Proceedings of the 15th New Zealand Geothermal Workshop 1993*, pp. 235-240.
- Omandam, V.D. (1987). Palinpinon I geothermal field: fluid collection system operation and experience. *Geothermal Institute, University of Auckland, New Zealand*, pp. 2 - 10.
- Omandam V.D. (1996). Operation and maintenance of the geothermal field fluid collection system of Palinpinon I production field. pp. 1 – 30.