WET-DRY COOLING ALTERNATIVES FOR GEOTHERMAL POWER PLANTS

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ABSTRACT

Most of the water produced from a steam-dominated geothermal reservoir is lost to the atmosphere through evaporation in the wet cooling towers used for waste heat disposal of power plants.
In order to increase the amount of steam condensate available for reinjection, thus contributing to a greater extent to the recharge of the reservoir, major modifications of the heat rejection system are needed.
To evaluate the feasibility of such changes, a technical and economical analysis was carried out for a 20 MW power plant, considering the following waste disposal systems: i) conventional wet cooling cycle; ii) dry cooling cycle; iii) hybrid (wet-dry and dry-wet) cycles; iv) air cooled condenser.
Heat rejection systems were evaluated on the basis of the unit cost of the additional condensate available for reinjection in the different configurations, with the currently used wet cooling system as the reference case.

1. INTRODUCTION

The long-term exploitation of the steam-dominated geothermal fields leads to a pressure decline of the reservoir and, consequently, to the reduction of the power that may be generated. This is due to the fact that the rate of the natural recharge (if any) is far too insufficient to compensate the steam extraction rate from the wells.
In order to extend the useful life of the field, reinjection of the excess steam condensate coming from the power plants is a common practice (Larderello, The Geysers). A variable amount of the reinjected water (depending on the reservoir characteristics and flow patterns) may be recovered as steam from the productive wells, by means of the heat content of the reservoir rocks.
Reinjection has also the advantage of providing a generally cost-effective way to dispose of a polluted stream that should otherwise be treated before being allowed to be discharged.
However, use of the steam condensate as the make-up to compensate for the evaporation losses in cooling towers leaves only 15 to 30 percent (depending of cooling tower characteristics and weather conditions) of the extracted steam available for reinjection.
On the other hand in most cases it would be far more desirable to reinject an amount of water comparable to the steam production rate.
This may be accomplished in two ways:
- recurring to alternate water sources (rivers, sewage waters);
- increasing the excess steam condensate available from power plants.

The scarcity of surface waters in the Larderello area makes the latter solution only to look as viable.
The reduction of the evaporation losses associated with the waste heat released in the environment requires major modifications to the existing evaporative, or wet, cooling tower system.

ENEL has under way both the construction of new power plants, in peripheral areas of the Larderello field, and the dismantling and replacement of old power plants with new ones, in the central part of the field. Hence, the decision was taken not to study retrofit additions or changes of the existing cooling systems, but rather top evaluate alternate designs for the units still to be built.
A typical (standardised) nominal 20 MW unit installed by ENEL is fed by 31 kg/s of steam and is provided with a direct-contact condenser, with an extraction pump placed close to the hot well to pump the circulating water to the cooling tower (Allegrini et al., 1985).
Minor flowrates of cold water are needed in the intermediate gas cooler of the centrifugal compressor(used for the NCG extraction from the condenser) and in a heat exchanger for lube oil cooling.
However, the great majority of cold water flows back into the condenser (kept at an absolute pressure of 8 kPa), with a typical design water-to-steam weight ratio of 45:1.
The cooling tower is composed of three induced draft counterflow cells (with a splash-type filling), having a total design capacity of 6000 m3/h of water flowrate, a design cold water temperature of 25 "C (at an ambient wet bulb temperature of 18.5 "C) and 10 "C cooling range.

2. COOLING ALTERNATIVES

To evaluate the feasibility of modifications of the heat rejection system, a technical and economical analysis has been carried out considering the following waste heat disposal systems:

1. conventional wet cooling cycle; this system has been described in the previous paragraph and represents the existing solution (figure 1)

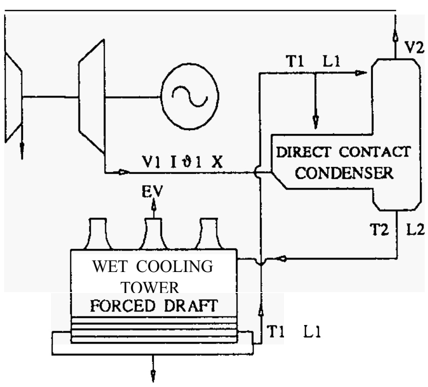

Figure 1: Conventional wet cooling cycle.

2. dry cooling cycle; this system is depicted in fig.2: the steam is condensed in the direct-contact condenser, and is then cooled in a forced-draft finned-tube dry tower and finally reinjected.

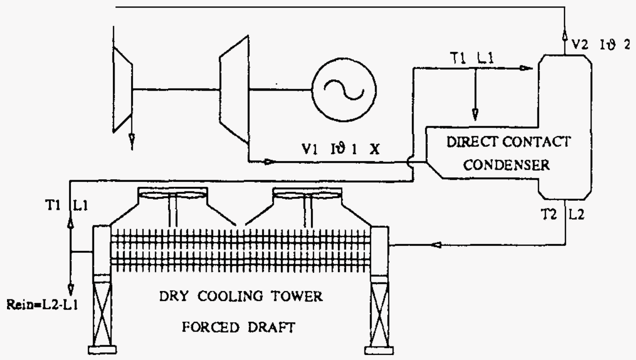

Figure **2:** Dry cooling cycle.

3. hybrid (wet-dry and dry-wet) cycles:
   - type **A:** it is mainly a wet cycle with a dry zone on tower top: this section has been studied for disposing 10, **21** or ***25 %*** of the total heat, respectively. This system operates in series as respect to water cooling, while air crosses the two zones and then mixes (fig. 3 and **4);** it may be also employed to reduce the environmental impact of the plant since it is plume-free.
   - type B: (serial dry-wet cooling): this solution is constituted by a dry cycle unit (designed for 80, 60 or 40 % of total heat rejection in our study) equipped with an additional finned-tube exchanger using humidified air as a cooling media (Fig.5). This system operates as a dry cycle during most of the year, but it utilises wet cooling in hot weather. The extent to which the dry tower is utilised would depend on the ambient wet and dry bulb temperatures.

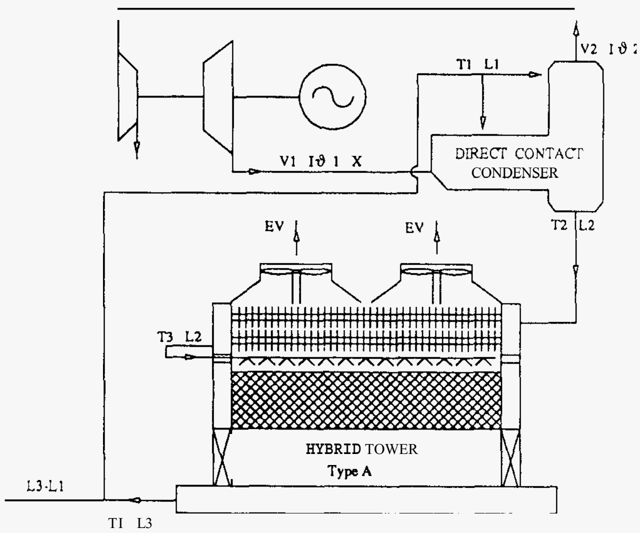

Figure 3: Hybrid (wet-dry) cicle.

4. air-cooled condenser (fig.6.1): this is a forced draft air cooled finned condenser, which operates condensing 80% of the total steam at design conditions ***(25* °C** temperature difference).
5. air cooled condenser followed by a small direct-contact condenser and an associated wet cooling cycle of reduced size: this system is an extension of the previous one, which condenses the remaining steam in a conventional cycle (fig.6.2)

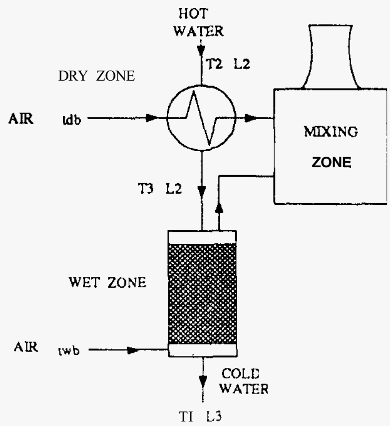

Figure **4:** Hybrid (wet-dry) cicle: tower principle of operations.

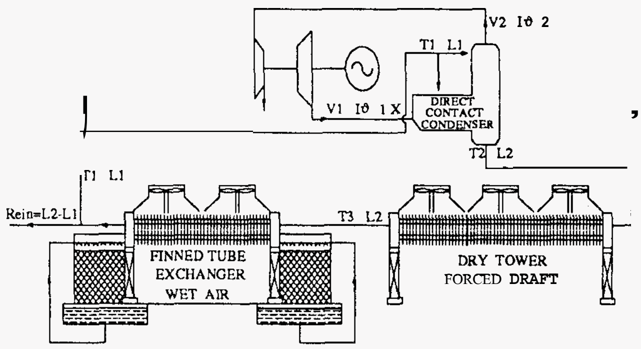

Figure **5:** Serial dry-wet cooling.

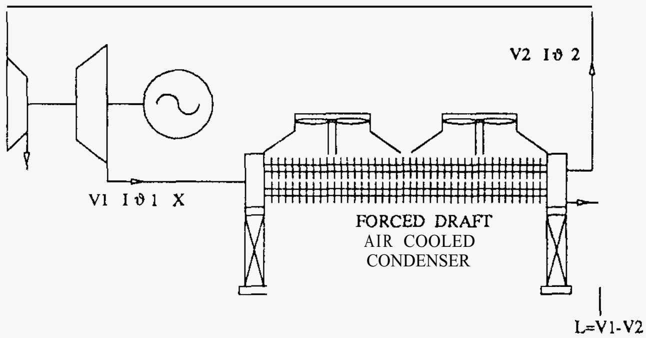

Figure 6.1: Air-cooled condenser

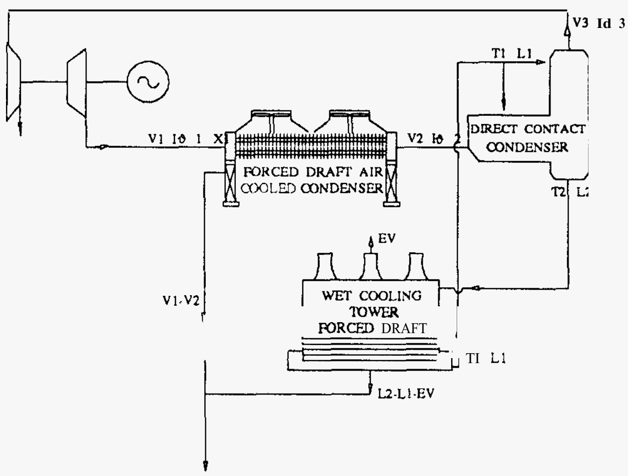

Figure 6.2: Air-cooled condenser equipped with a wet cooling cycle.

No attempt was made in this study to examine specific designs. The objective in examining the dry cooling alternatives in this study was rather to determine wether the economics of the alternatives were worth actual design effort or not.
The comparison between the different systems has been carried out considering the following parameters and data (Table I):

Table I

Steam flowrate	31 kg/s
Non-Condensable Gas content	5%
Steam pressure	500 kPa
Turbine discharge pressure	8 kPa
Steam quality at turbine outlet	0.867
Cooling water flowrate	3000/4600/6000 m³/h
Cooling water temperature (*)	25 °C
NCG temperature (*)	26 °C
Cooling range (*)	10 °C
Exhaust air recirculation factor	0.1
Wet-bulb temperature (**)	18.5 °C
Relative humidity (yearly average)	70%
Max. water pumping head	9.8 m
Yearly operating time	8000 h
Depreciation life	25 years
Discount rate	8%
Energy value	65 Lit/kWh

(*) For the reference case only
(**) For the reference case only; for the other cases the annual distribution of wet bulb temperatures has been considered in the calculation.
The kWh value of £ 65 was chosen as it represents the average cost of the power produced by conventional fossil-fired power plants.

3. APPROACH AND SOLVING METHODS

A plant cycle computer model was developed to allow case by case studies to be conducted for the different cooling options. There are several sub-models which evaluate the performances of the different units and evaluate the annual cost of reinjected water on the basis of the distribution of wet bulb temperatures.
Figure 7 provides a scheme of the model for the direct-contact condenser wet-cooling options. It is a trial-and-error method which starts with cold water temperature T, as the input of the direct contact condenser model (based on actual data, Allegrini *et al* (1985)).
This step, on the basis of heat and mass balances on condenser and steam turbine performances, provides the inputs to the cooling tower loop (namely water flowrate L_2 and temperature T_2). On the basis of air conditions (wet bulb temperature t_{WB} and relative humidity RH_1), the cooling tower sub model evaluates the temperature T_1 of the water to be fed to the direct contact condenser by means of the Merkel approach (Merkel, 1925;Jackson,1951). When T_1 is obtained which solves both the loops, condensate available for reinjection Rj is calculated (by evaluating the condition of humid air leaving the tower) as well as the net power produced in the cycle

$$W_{NET} = W_{Turb} - W_{Extr} - W_{Fan} - W_{Pump} \quad 1$$

where the power required for NCG extraction, water pumping and cooling tower fans are evaluated on the basis of available data on turbine and operating machine performances. These calculations can be performed for any desired input condition.
Rj and W_{NET} are then evaluated on annual basis by

$$\sum_{i=1}^{8000} W_{NET,i} \cdot H_i; \quad \sum_{i=1}^{8000} Rj_i \cdot H_i \quad 2$$

where H_i is the number of hours per year with a certain wet bulb temperature. (figure **8**).

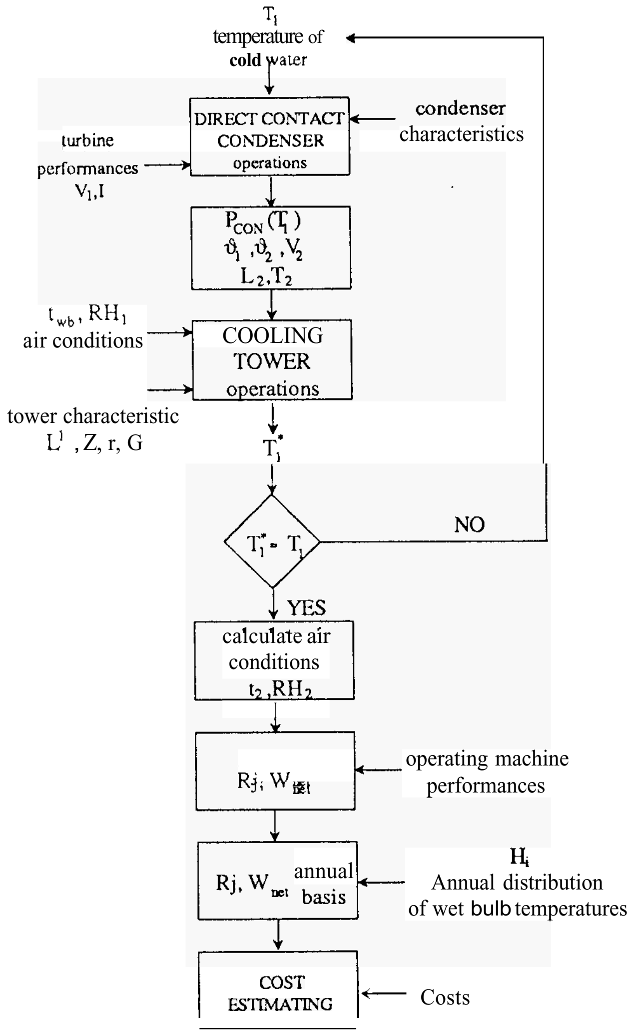

Figure 7: Schematic of the procedure: direct contact condenser/wet cooling

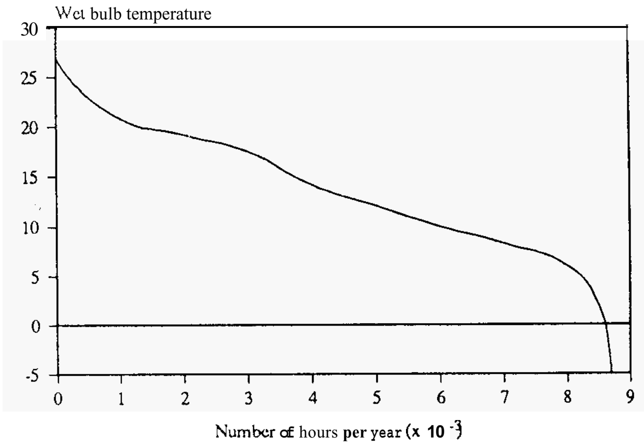

Figure 8: Annual distribution of wet bulb temperature: number of hours for which t_{wb} is greater than the value

The total annual cost is calculated taking into account the yearly depreciation expense of the condenser and cooling equipment and the revenue loss associated with the decrease in year-round power generation compared with the reference case.
It is worthwhile to notice that for each cooling option a rough design optimization is operated which minimizes the total annual cost of the installation. This design, carried out by means of overall equations and cost estimates, provides the characteristics of each cooling device (wet, dry, hybrid, air cooled finned-tube condenser) to be used in the cycle model described above.
Cost of plant and devices are based on current prices of equipment in Italy.

4. RESULTS AND DISCUSSION

Table II reports the amount of condensate available yearly for reinjection, Rj, for the different systems studied, as a function of the cooling water flow. Dry solutions yield the major quantities, as expected . Direct air condensation options (cases 4 and 5) show the consequences of condensing 80 % of total steam only.

Table II :Condensate available yearly for reinjection (m^3)

Cooling water flow m^3/h	3000	4600	6000
Wet tower	245700	265100	264500
Dry tower	829600	824100	819700
Hybrid type "A" 10% dry	299200	319600	317000
Hybrid type "A" 20% dry	372900	380700	374800
Hybrid type "A" 25% dry	407000	414500	407200
Hybrid type "B" 80% dry		791100	777000
Hybrid type "B" 60% dry		780000	756000
Hybrid type "B" 40% dry		765700	730000
Air cooled condenser		691000	
Air cooled condenser + wet cycle		704000	

Figure 9 shows the ratio between the increase of the overall cost of power generation and the increase in the amount of condensate available yearly for injection, with respect to the presently adopted cooling option.
This ratio is plotted against the cooling water flow. Options 4 and 5 give figures independent from this parameter, obviously.
It is apparent that a flowrate of 4600 m^3/h represents the most convenient choice. Furthermore, type B hybrid options (serial dry-wet cooling) seem to give the most convenient ratio between additional cost and reinjectable condensate. While the direct air condenser alone shows a poor performance, the addition of a small scale wet cooling cycle makes this option comparable with the best.
Figure 10 reports the variation of the cost of additional condensate made available for reinjection versus the kWh value, for the different options considered. This parameter may be directly compared to the costs of alternate water supplies which could be used for reservoir recharge, e.g. surface or sewage waters. The trend of the increase of this cost with the kWh value is similar for all the cases examined, showing that the choice of cooling alternative is not strongly affected by the power value. It should be pointed out that type B hybrid options again perform best from a technical and economical standpoint.
Figure 11 reports the cost of the kWh produced with the additional condensate injected versus the recovery rate of injected condensate as new steam. This value has been calculated assuming that the recovery of the new steam is in the same year

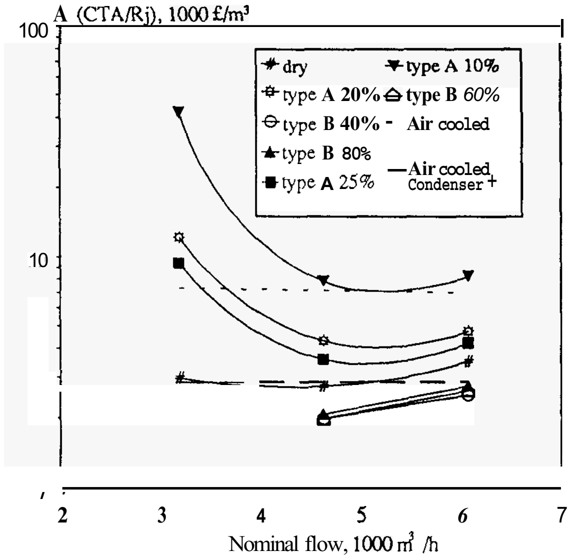

Figure 9: Ratio between the increase of the overall cost of power generation and the increase in the amount of condensate yearly available for injection

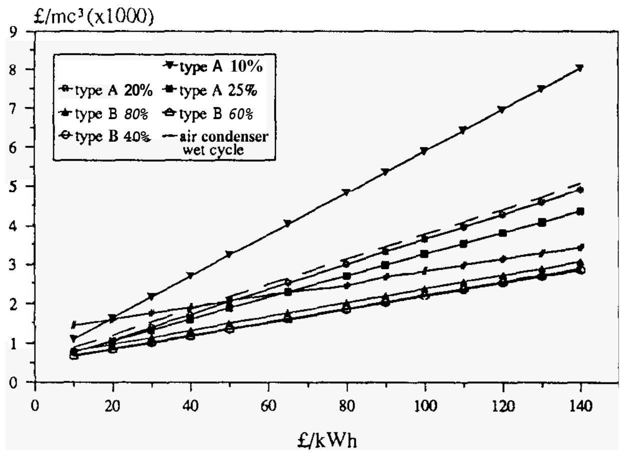

Figure 10: Cost of the additional condensate available for reinjection vs. kWh value.

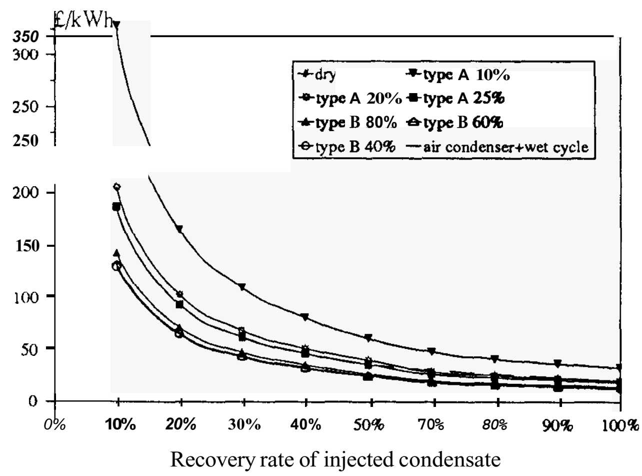

Figure 11: Cost of the kWh with additional condensate injection vs. recovery rate.

that water is injected, with a steam rate of 8.2 kg/kWh. This parameter may be directly compared with the cost of alternate steam supplies which could be obtained drilling deeper or pheripheral wells in the declining reservoir. It can be seen that recovery rates higher than fifty percent make most of the options allowing enhanced injection rates economically viable.

5.CONCLUSIONS

This study has shown that some of the cooling options examined have a good performance both from a technical and economical standpoints.
Further work is needed, however, in order to progress from the feasibility study carried out to a more accurate and detailed design, featuring vendor quotations instead of the rough costing herein performed.
Nevertheless the results of the present study may be used as a guideline with the aim of comparing the convenience of obtaining the amount of water needed for the recharging of the reservoir with a different cooling system or from other water sources.

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