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GEOTHERMAL POWER PLANTS

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ABSTRACT

The paper gives an overview of the existing power plant technology. It addresses various problems that have been encountered, and outlines countermeasures that have been applied. Two main types of geothermal power plants are common, the condensing power plant, using fluid from reservoirs with temperatures in the range 200–320°C, and the binary fluid power plant using temperatures as low as 120°C. Also featured are the principal advantages appropriate to the utilisation of geothermal resources for production of electricity.

The paper moreover touches upon some of the advantages accruable from the integrated use of geothermal resources (using the same resource for electricity production in cascade or parallel with production of hot water for alternative uses), taking hybrid conversion as a case in point.

Also featured is a worldwide overview of the geothermal power plants by Bertani (under the auspices of IGA in 2010). The survey categorises the power plants by country and type of conversion system used, giving the installed capacity, annual electricity produced, number of units and the role of the geothermal generation with respect to the country's total electricity generation and total power demand. Also addressed is the worldwide distribution of geothermal power plants by plant type and the distribution of unit capacity and turbine inlet pressure. Finally an earlier survey presented by Bertani in 2005 features the effect of resource temperature on the power generation density.

Environmental abatement measures, such as re-injection of the spent (denuded of most of its thermal energy) geothermal fluid and methods of minimising atmospheric contamination by CO_2 and H_2S gases are also outlined, and so are the main associated technical problems.

The paper closes with a comprehensive list of the parameters that should be considered in designing a sustainable geothermal application scenario.

1. INTRODUCTION

The generation of electrical power using the thermal energy contained in the fluid circulating in deep lying formations in geothermal areas is typically quite feasible in the fluid temperature range of 200°C to 320°C, which characterises so called high-temperature (high enthalpy) geothermal areas. Geothermal fluid of this temperature is generally mined using current technology at resource depths between about 1200 m to 2500 – 3000 m in Iceland and most other geothermal areas of the world, for instance the USA, the Philippines, Indonesia, Japan, New Zealand, Mexico, Kenya and El Salvador to name a few.

Geothermal energy is renewable, when measured relative to human age spans, and generally categorised as such. It is environmentally benign ("green") and has many advantages over other renewable energy resources, such as hydro, wind, bioenergy and wave energy. The following are the more important of these advantages:

- High degree of availability (>98% and 7500 operating hrs/annum common);
- Low land use;
- Low atmospheric pollution compared to fossil fuelled plants;
- Almost zero liquid pollution with re-injection of effluent liquid;
- Insignificant dependence on weather conditions; and
- Comparatively low visual impact.

In compliance with current environmental, resource and economic sustainability principles it (Axelsson et al., 2001, 2003, and 2005) is important to select technologies and operational systems for the highest possible over all thermal efficiency for extracting the useful thermal energy, contained in the fluid, before it is returned back to the reservoir. The advantage of adopting such policies is the reduced number of production and injection wells required, less replacement drilling, higher level of sustainability, and greater environmental benefits.

These advantages may be attained in several ways, the optimal of which are multiple use (e.g. simultaneous electricity plus hot water production) systems and hybrid power plants.

The following chapter addresses the most common types of technologies applied in the conversion of geothermal energy into electric power; reviews some of the associated problems, and available countermeasures.

2. OVERVIEW OF POWER PLANT DESIGNS

This chapter addresses the geothermal to electrical power conversion systems typically in use in the world today. These may be divided into three basic systems, wiz:

- **Flashed steam/dry steam condensing system**; resource temperature range from about 320°C to some 230°C.
- **Flashed steam back pressure system**; resource temperature range from about 320°C to some 200°C.
- **Binary or twin-fluid system** (based upon the Kalina or the Organic Rankin cycle); resource temperature range between 120°C to about 190°C.

In addition to the above three basic power conversion systems, there are in use, the so called hybrid systems, which are in fact a combined system comprising two or more of the above basic types in series and/or in parallel.

Condensing and back pressure type geothermal turbines are essentially low pressure machines designed for operation at a range of inlet pressures ranging from about 2 – 20 bar, and saturated steam. The back pressure turbines have low thermal efficiency and are manufactured in relatively small sizes i.e. 0.5-5 MW. The condensing turbines are more efficient (by factor of 2 to 4) than the back pressure turbines. They are generally manufactured in larger output module sizes, commonly of the following power ratings: 25 MW, 35 MW, 45 MW, 55 MW and 105 MW (the largest currently manufactured geothermal turbine unit is 117 MW). Binary type low/medium temperature units, whereof the Kalina Cycle or Organic Rankin Cycle type, are typically manufactured in smaller modular sizes, i.e. ranging from 250 kW to 10 MW_e in size. Larger units specially tailored to a specific use are, however, available typically at a somewhat higher price.

Typical geothermal back pressure, condensing, binary and hybrid systems are depicted in diagrams on Figures 1, up to 6.

2.1 Back pressure type systems

Back pressure type systems (Figure 1) are the simplest of the above, least expensive and have the lowest overall thermal efficiency. Currently they are largely used in multiple use applications (such as combined electricity and hot water production), to provide temporary power during resource development, in the mineral mining industry where energy efficiency has low priority, and most importantly as part of a hybrid system. Their stand-alone scope of application covers the whole of the normally useful geothermal resource temperature range, i.e. from about 320°C to some 200°C.

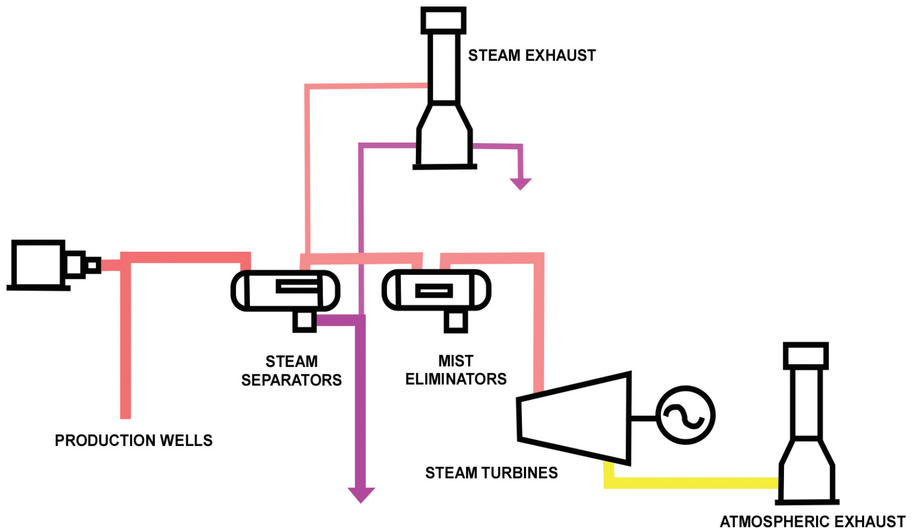

FIGURE 1: Typical backpressure turbine/generator conversion system

2.2 Condensing type systems

Condensing type systems (Figures 2 and 3) are somewhat more complex in as much as they require a condenser, and gas exhaust system. This is the most common type of power conversion system in use today. The turbine is an expansion machine and the unit normally comprises two turbine sets arranged coaxially cheek to cheek (hp end to hp end) to eliminate/minimise axial thrust. To improve its thermal efficiency and flexibility, the unit is also available in a twin pressure configuration (say 7 bar/2 bar), where the lower pressure (say 2 bar) steam is induced downstream of the third expansion stage. When these condensing turbines are used in a co-generation scheme they may be fitted with extraction points to provide low pressure steam to the district heating side. The hallmarks of the condensing system are long and reliable service at reasonable over all thermal efficiency, and good load following capability. Their stand-alone scope of application covers the high to medium (200–320°C) geothermal resource temperature range.

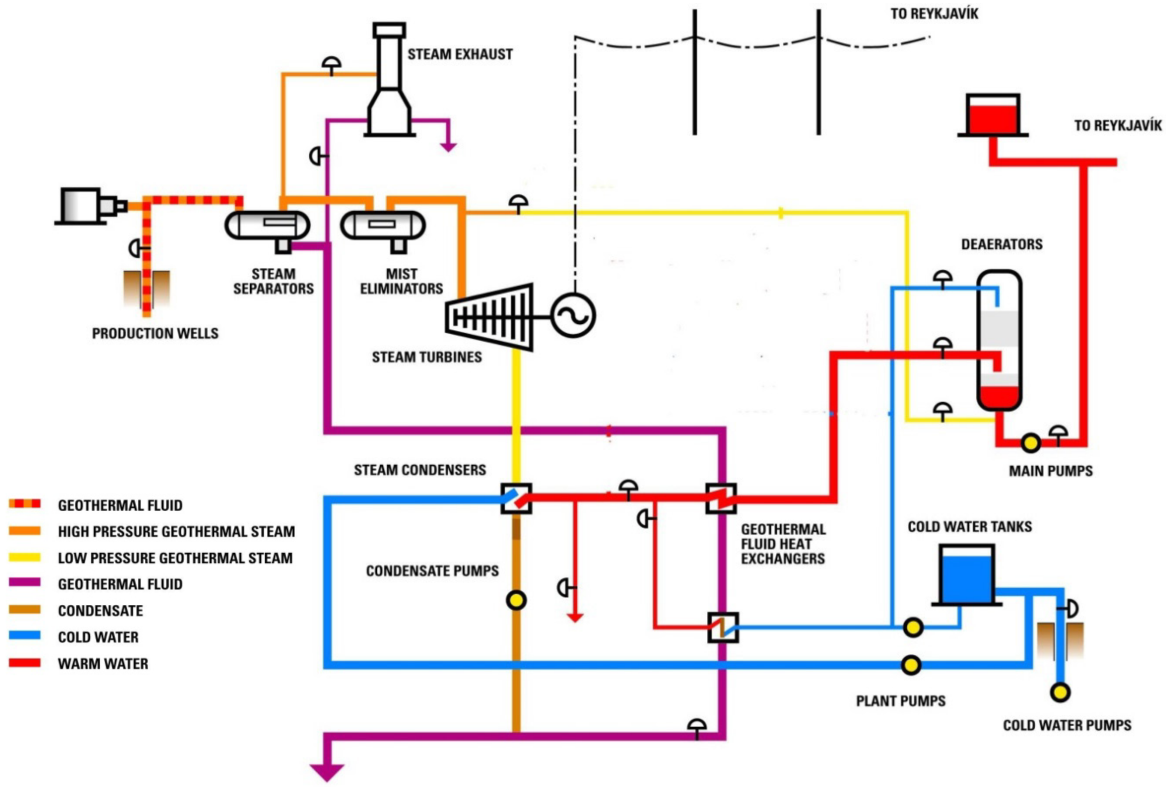

FIGURE 2: Condensing type turbine/generator unit in combined utilisation (courtesy of Reykjavík Energy)

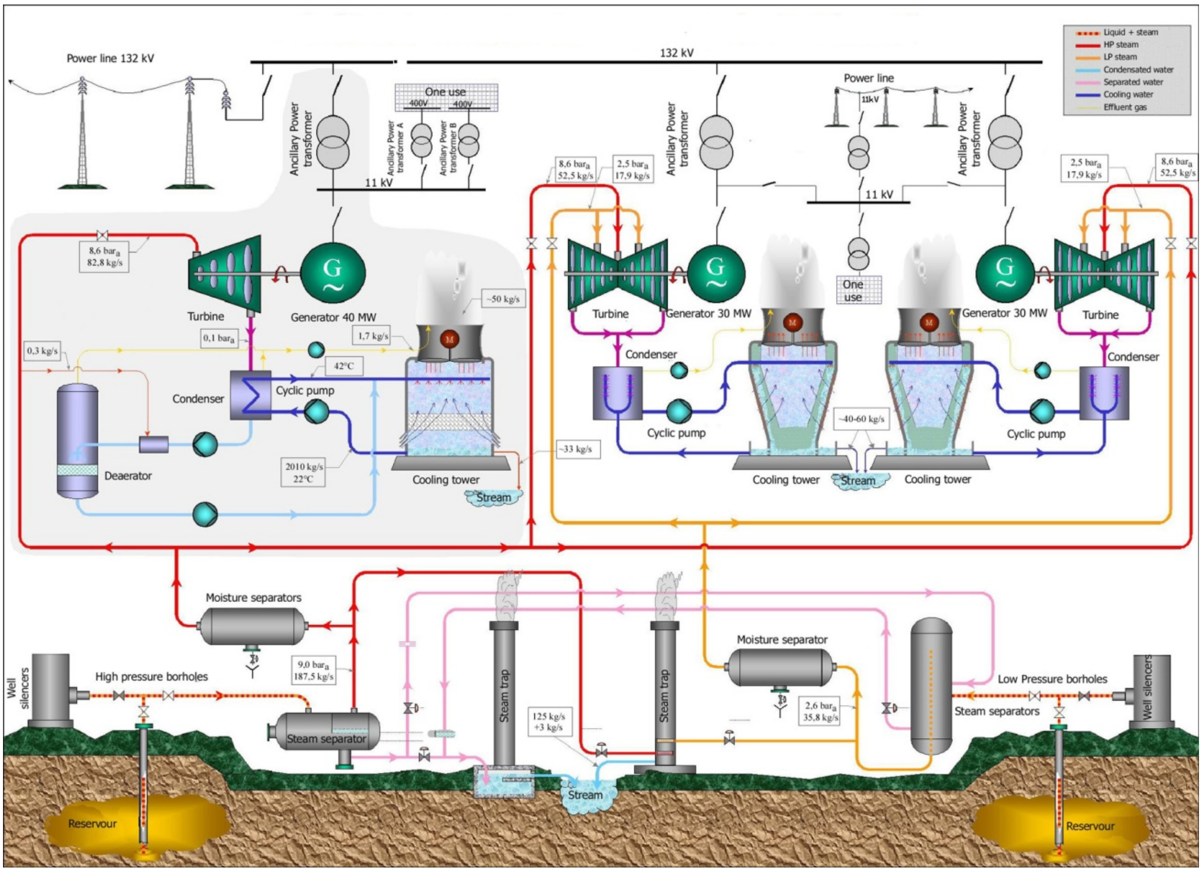

FIGURE 3: Condensing single and twin pressure t/g unit (courtesy of Landsvirkjun, Iceland)

2.3 Binary type systems

Binary type systems are of a quite different concept. The thermal energy of the geothermal fluid from the production well field is transferred to a secondary fluid system via heat exchangers. The geothermal fluid is thus isolated from the secondary fluid, which comprises a low boiling point carbohydrate (butane, propane etc.) or specially designed low boiling point fluid, which complies with low ozone layer pollution constraints, in the case of the Organic Rankine Cycle (Figure 4). In the case of the Kalina Cycle (Figure 5), the secondary or motive liquid comprises water solution of ammonia. This heated secondary fluid thereupon becomes the motive fluid driving the turbine/generator unit. The hallmark of the binary system is its ability to convert low-temperature (120–190°C) geo-thermal energy to electric power albeit at a relatively low overall thermal efficiency, and to isolate scaling, gas and erosion problems at an early point in the power conversion cycle in a heat exchanger. The binary system is quite complex and maintenance intensive.

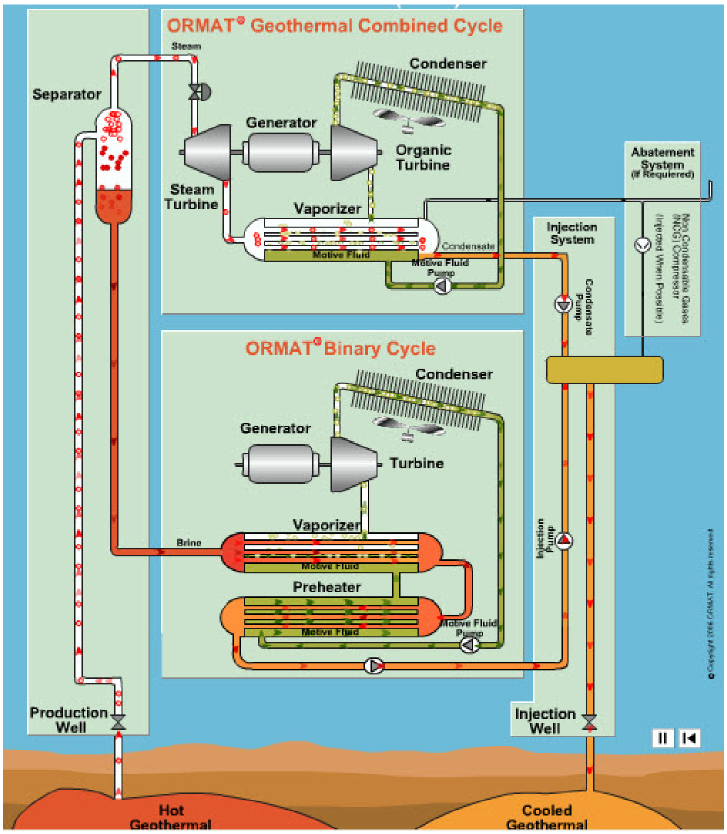

FIGURE 4: Ormat type Organic Rankine cycle (courtesy of Ormat Technologies Inc.)

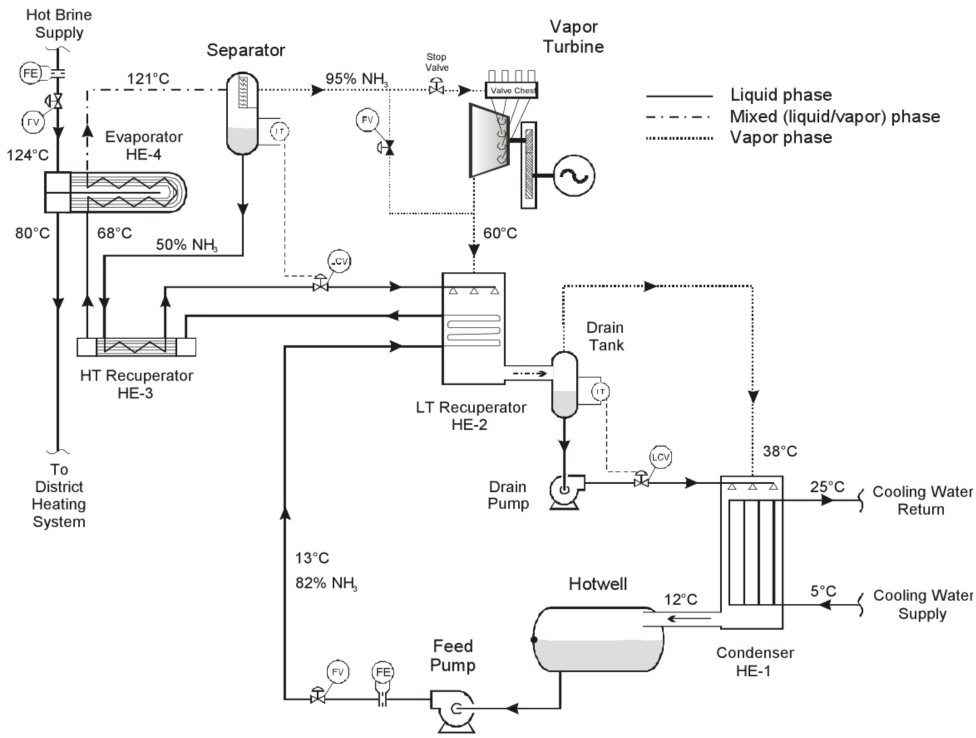

FIGURE 5: Kalina cycle converter (courtesy Xorka Ltd.)

2.4 Hybrid conversion system

The hybrid conversion system is a combined system, as said before, encompassing two or more of the basic types in series and/or in parallel. Their hallmark is versatility, increased overall thermal efficiency, improved load following capability, and ability to efficiently cover the medial (200–260°C) resource temperature range (Tester, 2007). To illustrate the concept a hybrid configuration encompassing a backpressure flashed steam turbine/generator unit and three binary units in series is depicted in Figure 6. Two of the binary units utilise the exhaust steam from the back pressure unit, and the remaining binary t/g unit utilises the energy content of the separator fluid. The fluid effluent streams are then combined for re-injection back into the geothermal reservoir, so maintaining sustainability of the resource in a most elegant manner.

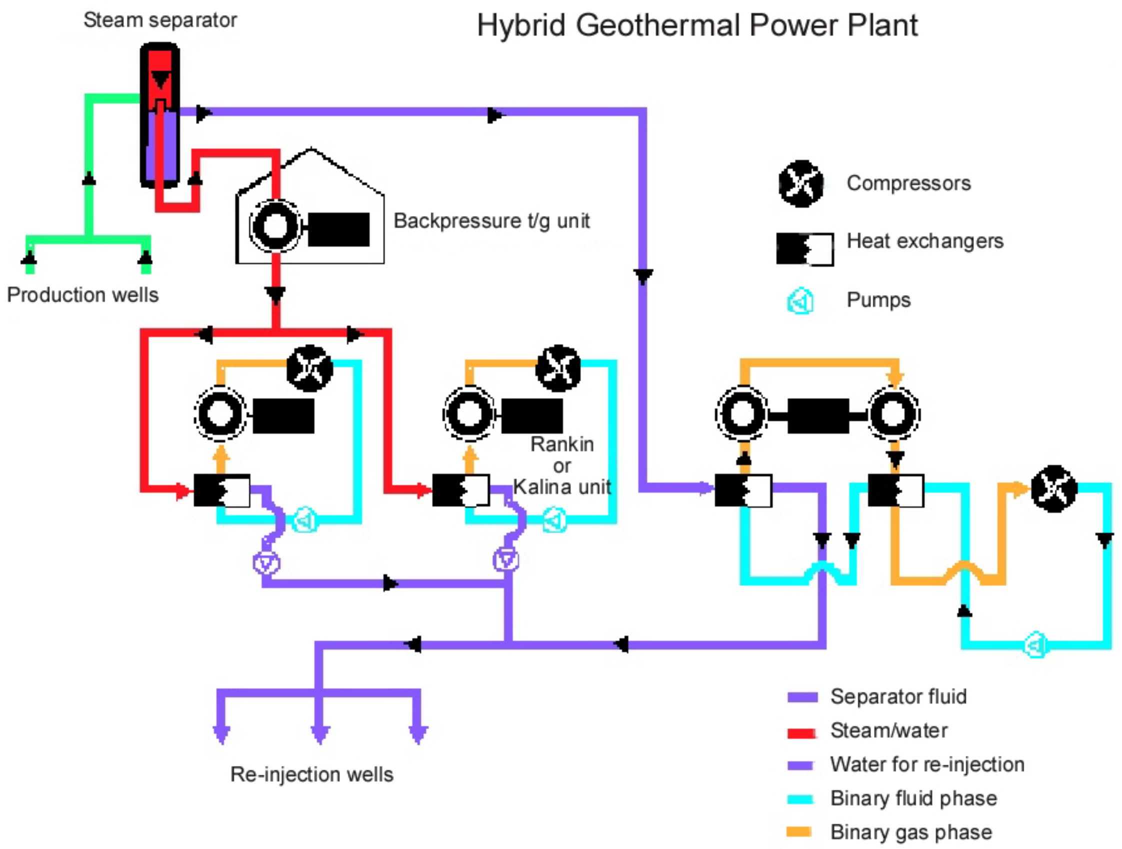

FIGURE 6: Hybrid conversion system

3. WORLD SURVEY ON GEOTHERMAL POWER PLANTS

Summary reports of the worldwide geothermal utilisation are presented at the World Geothermal Congresses organized by the International Geothermal Association (IGA) every five years. In Table 1 the electricity generation from geothermal resources in 2010 presented at the WGC 2010 in Bali, Indonesia, is reproduced (Bertani, 2010). Figure 7 shows the installed capacity in MW and the total number of units for each category from the same source, based on the standard plant classification. It shows that the largest installed capacity corresponds to single-flash units.

Figure 8 shows data from a worldwide survey made by the Japan Geothermal Energy Association in 2001. It shows the distribution of unit capacity of geothermal power plants (left) and the distribution of inlet pressure of all turbine units included in the survey (right). The sizes of 5, 20 and 55 MWe are clearly the most common, although several small units are in operation as well as a small number of much larger units. The inlet pressure lies generally in the range 6-8 bars, but also here a wide range of values is reported.

TABLE 1: Geothermal power generation worldwide in 2010 (Bertani, 2010)

	Installed capacity MW_e	**Annual electricity produced GWh/year**	**Number of units**
Australia	1.1	0.5	2
Austria	1.4	3,8	3
China	24	150	8
Costa Rica	166	1,131	6
El Salvador	204	1,422	7
Ethiopia	7.3	10	2
France (Guadeloupe)	16	95	3
Germany	6.6	50	4
Guatemala	52	289	8
Iceland	575	4,597	25
Indonesia	1,197	9,600	22
Italy	843	5,520	33
Japan	536	3,064	20
Kenya	167	1,430	14
Mexico	958	7,047	37
New Zealand	628	4,055	33
Nicaragua	88	310	5
Papua New Guinea	56	450	6
Philippines	1,904	10,311	56
Portugal	29	175	5
Russia	82	441	11
Thailand	0.3	2	1
Turkey	82	490	5
USA	3,093	16,603	210
TOTAL	**10,715**	**67,246**	**526**

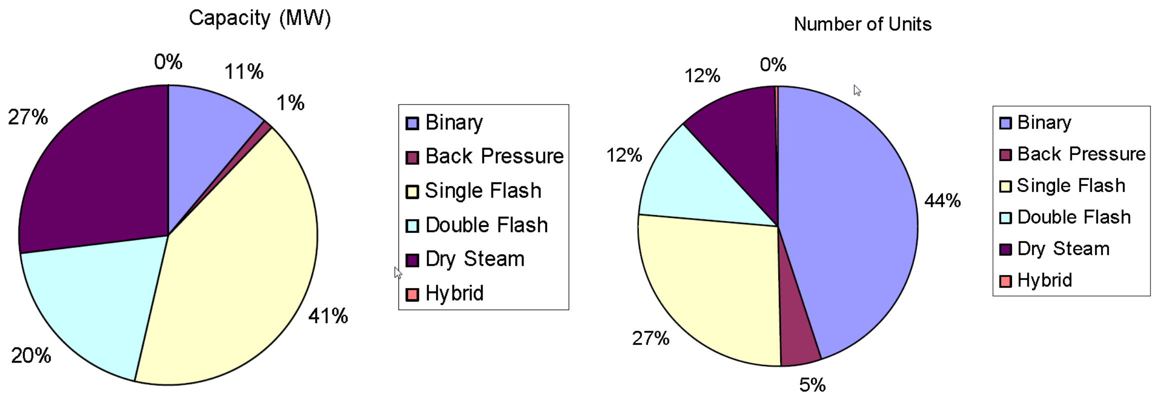

FIGURE 7: Worldwide distribution of geothermal power plants by plant type, based on installed capacity (left) and number of units (right)

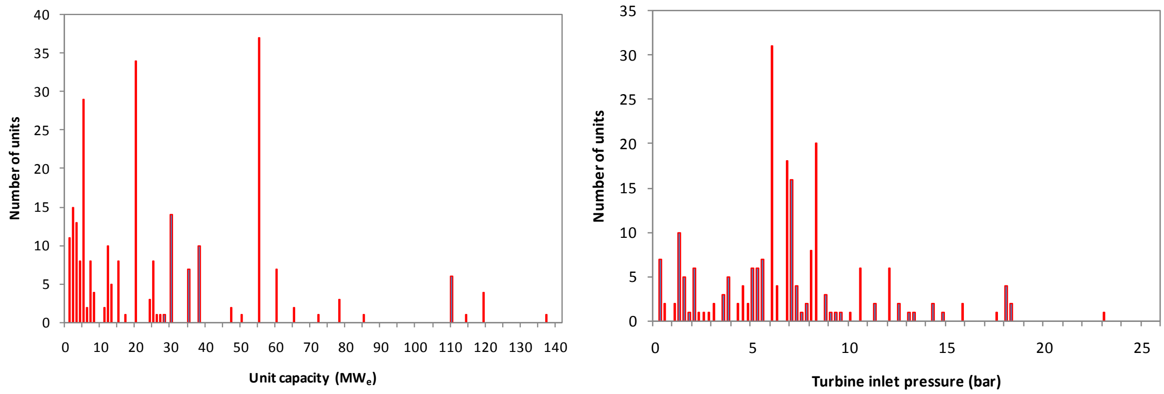

FIGURE 8: Distribution of unit capacity (left) and turbine inlet pressure (right) in geothermal electricity production worldwide (Japan Geothermal Energy Association, unpublished data sheets)

Bertani's paper from WGC-2005 gives calculated values for power density (MW_e/km^2) as well as the number of productive wells per square kilometre; see Table 2.

TABLE 2: Effect of reservoir temperature on production indices. Hotter >250°C, and cooler <250°C. Values in the second and third column are mean and standard deviations (Bertani, 2005)

Index	**Hotter**	**Cooler**
Power density (MW_e/km^2)	7.8 ± 6.4	6.5 ± 5.2
Well density ($Wells/km^2$)	1.9 ± 1.4	1.9 ± 1.6
Well productivity (MW_e/well)	4.7 ± 3.3	4.2 ± 2.2

4. PREVAILING PROBLEM TYPES AND COUNTERMEASURES IN OPERATION OF POWER PLANTS

Different parts of the surface components of power generation system have associated different problem flora. It is therefore expedient to divide the system into the following seven principal portions:

- **Power house equipment:** Comprising of turbine/generator unit complete with condenser, gas exhaust system.
- **Automatic control and communication system:** Consisting of frequency control, servo valve control, computer system for data collection, resource and maintenance monitoring, internal and external communication etc.
- **Cooling system:** Cooling water pumps, condensate pumps, fresh water (seawater) cooling, or cooling towers.
- **Particulate and/or droplet erosion:** This is an erosion problem that is typically associated with the parts of the system where the fluid is accelerated (e.g. in control valves, turbine nozzles, etc.) and/or abruptly made change direction (e.g. via pipe bends, T-fittings or wanes).
- **Heat exchangers:** These are either of the plate or the tube and shell type. These are generally only used in binary and hybrid type conversion systems, and/or in integrated systems.
- **Gas evacuation systems:** High temperature geothermal fluid contains a significant quantity of non-condensable gases ($C0_2$, N_2, H_2S, and others). These have to be removed for instance from the condensing plant for reasons of conversion efficiency. Some countries require the gas to be cleaned of H_2S or Hg to minimise atmospheric pollution.

- **Re-injection system:** Comprising liquid effluent collection pipelines, injection pumps, injection pipelines, injection wells and control system.
- **Chemical injection systems:** These are applied in order to reduce and control corrosion and scaling in production/re-injection wells and surface equipment.

The problem areas typical for each of these conversion components are now outlined in turn each under its own chapter heading. It must, however, be emphasised that the featured problems and counter measures can only be addressed in general terms because of their site and locality specific nature. A locality specific case by case pre-engineering study is decidedly required in order to address this subject matter in any detail.

4.1 Power house equipment

4.1.1 Turbine

The problems potentially associated with the turbine are scaling of the flow control valve and nozzles (primarily in the stator inlet stage); stress corrosion of rotor blades; erosion of turbine (rotor and stator) blades and turbine housing.

The rate and seriousness of scaling in the turbine are directly related to the steam cleanliness, i.e. the quantity and characteristics of separator "carry-over". Thus the operation and efficiency of the separator are of great importance to trouble free turbine operation. Prolonged operation of the power plant off-design point also plays a significant role.

Most of the scaling takes place in the flow control valve and the first stator nozzle row. The effect of this scaling is:

- A significant drop-off in generating capacity as sufficient steam cannot enter the turbine; and
- Sluggish response to load demand variations.

This situation is easily monitored, since the build-up of scales causes the pressure in the steam chest between the control valve and the inlet nozzles to increase over time.

Significant turbine and control valve scaling is avoided by the adoption of careful flasher/separator plant operating practices that minimise "carry-over", and moreover selecting a high efficiency mist eliminator by the power plant.

Significant scaling in turbine and control valve requires scheduled maintenance stops for inspection and cleaning, every second or third year.

Another means of reducing turbine cleaning frequency, is to inject condensate into the inlet steam during plant operation and run the turbine at say 10% wetness for a short period. This washes away nozzle scaling, in particular the calcite component thereof, and simultaneously weakens the silica scale structure, which then tends to break off. This cleaning technique if properly applied has been found to reduce the frequency of major turbine overhaul.

4.1.2 Generator

It must be pointed out here that high-temperature steam contains a significant amount of carbon dioxide CO_2 and some hydrogen sulphite H_2S and the atmosphere in geothermal areas is thus permeated by these gases. All electrical equipment and apparatus contains a lot of cuprous or silver components, which are highly susceptible to sulphite corrosion and thus have to be kept in an H_2S free environment. This is achieved by filtering the air entering the ventilation system and maintaining slight overpressure in the control room and electrical control centres.

The power generator is either cooled by nitrogen gas or atmospheric air that has been cleaned of H_2S by passage through special active carbon filter banks.

4.1.3 Condenser

The steam-water mixture emitted from the turbine at outlet contains a significant amount of non-condensable gases comprising mainly CO_2 (which is usually 95–98% of the total gas content), CH_4 and H_2S, and is thus highly acidic. There is a condenser that receives the steam directly from the turbine which is a large piece of equipment, either of the direct contact type (water spray) or indirect contact (heat exchanger). The direct contact type is more common. Condensation of the steam creates a vacuum (about 80-90%, 0.1-0.2 bar a) inside the condenser which improves the turbine efficiency markedly. The vacuum level is controlled by the temperature of the cooling water. Thus in warm weather or hot climates the vacuum cannot be maintained as high which causes a decline in the turbine output. Vacuum pumps are required to extract the non-condensable gases in order to maintain the level of vacuum. Since most high-temperature geothermal resources are located in arid or semi-arid areas far removed from significant freshwater (rivers, lakes) sources, the condenser cooling choices are mostly limited to either atmospheric cooling towers or forced ventilation ones. The application of evaporative cooling of the condensate results in the condensate containing dissolved oxygen in addition to the non-condensable gases, which make the condenser fluid highly corrosive and require the condenser to be clad on the inside with stainless steel; condensate pumps to be made of stainless steel, and all condensate pipelines either of stainless steel or glass reinforced plastic. Addition of caustic soda is required to adjust the pH in the cooling tower circuit. Make-up water and blow-down is also used to avoid accumulation of salts in the water caused by evaporation.

A problem sometimes encountered within the condenser is the deposition of almost pure sulphur on walls and nozzles within the condenser. This scale deposition must be periodically cleaned by high pressure water spraying etc.

4.2 Automatic control and communication system

Modern power plants are fitted with a complex of automatic control apparatus, computers and various forms of communication hardware. These all have components of silver and cuprous compounds that are extremely sensitive to H_2S corrosion. They are therefore housed inside “clean enclosures”, i.e. airtight enclosures that are supplied with atmospheric air under pressure higher than that of the ambient atmospheric one and specially scrubbed of H_2S. Entrance and exit from this enclosure is through a clean air blow-through antechamber to prevent H_2S ingress via those entering the enclosure. A more recent design is to clean all the air in all control rooms by special filtration and maintain overpressure.

Most other current carrying cables and bus bars are of aluminium to prevent H_2S corrosion. Where copper cables are used a field applied hot-tin coating is applied to all exposed ends.

4.3 Cooling tower system

4.3.1 Cooling tower and associated equipment

Most high-temperature geothermal resources are located in arid or semi-arid areas far removed from significant freshwater (rivers, lakes) sources. This mostly limits condenser cooling choices to either atmospheric cooling towers or forced ventilation ones. Freshwater cooling from a river is, however, used for instance in New Zealand and seawater cooling from wells on Reykjanes, Iceland.

In older power plants the atmospheric versions and/or barometric ones, the large parabolic ones of concrete, were most often chosen. Most frequently chosen for modern power plants is the forced ventilation type because of environmental issues and local proneness to earth quakes.

The modern forced ventilation cooling towers are typically of wooden/plastic construction comprising several parallel cooling cells erected on top of a lined concrete condensate pond. The ventilation fans are normally vertical, reversible flow type and the cooling water pumped onto a platform at the top of the tower fitted with a large number of nozzles, through which the hot condensate drips in counter-flow to the airflow onto and through the filling material in the tower and thence into the condensate pond, whence the cooled condensate is sucked by the condenser vacuum back into the condenser. To minimise scaling and corrosion effects the condensate is neutralised through pH control, principally via addition of sodium carbonate.

Three types of problems are found to be associated with the cooling towers, i.e.

- Icing problems in cold areas;
- Sand blown onto the tower in sandy and arid areas; and
- Clogging up by sulphitephylic bacteria.

The first mentioned is countered by reversing the airflow cell by cell in rotation whilst operating thus melting off any icing and snow collecting on the tower.

The second problem requires frequent cleaning of nozzles and condensate pond. The last mentioned is quite bothersome. It is most commonly alleviated by periodic application of bacteria killing chemicals, and cleaning of cooling tower nozzles by water jetting. The sludge accumulation in the condensate pond, however, is removed during scheduled maintenance stops. A secondary problem is the deposition of almost pure sulphur on walls and other surfaces within the condenser. It must be periodically cleaned by high pressure water spraying etc., which must be carried out during scheduled turbine stops.

4.4 Condenser pumping system

The condensate pumps must, as recounted previously, be made of highly corrosion resistant materials, and have high suction head capabilities**.** They are mostly trouble free in operation.

The condensate pipes must also be made of highly corrosion resistant materials and all joints efficiently sealed to keep atmospheric air ingress to a minimum, bearing in mind that such pipes are all in a vacuum environment. Any air leakage increases the load on the gas evacuation system and thus the ancillary power consumption of the power plant.

4.5 Particulate/droplet erosion and countermeasures

Geothermal production wells in many steam dominated reservoir have entrapped in the well flow minute solids particles (dust), which because of the prevailing high flow velocities may cause particulate erosion in the well head and downstream of it. Such erosion in the well head may, in extreme cases, cause damage of consequence to wellhead valves, and wellhead and fittings, particularly in T-fittings and sharp bends in the fluid collection pipelines. This is, however, generally not the case and such damage mostly quite insignificant. It is, however, always a good practice to use fairly large radius pipe bends to minimise any such erosion effects.

Droplet erosion is largely confined to the turbine rotor and housing. At exit from the second or the third expansion stage the steam becomes wet and condensate droplets tend to form in and after the expansion nozzles. Wetness of 10% to 12% is not uncommon in the last stages. The rotor blades have furthermore reached a size where the blade tip speeds become considerable and the condensate droplets hit the blade edges causing erosion. The condensate water which has become acidic from the dissolved non condensable gas attaches to the blades and is thrown against the housing. This water has the potential to cause erosion problems. The most effective countermeasures are to fit the blade edges of the last two stages with carbide inserts (Stellite) that is resistant to the droplet impingement and the housing with suitable flow groves that reduce the condensate flow and thereby potential erosion damage.

In addition to the erosion the blades and rotor are susceptible to stress corrosion in the H_2S environment inside the turbine housing. The most effective countermeasure is to exercise great care in selecting rotor, expansion nozzle and rotor blade material that is resistant to hydrogen sulphite corrosion cracking. The generally most effective materials for the purpose are high chromium steels.

4.6 Heat exchangers

In high-temperature power generation applications heat exchangers are generally not used on the well fluid. Their use is generally confined to ancillary uses such as heating, etc. using the dry steam. In cogeneration plants such as the simultaneous production of hot water and electricity, their use is universal. The exhaust from a back pressure turbine or tap-off steam from a process turbine is passed as primary fluid through either a plate or a tube and shell type heat exchanger. The plate type heat exchanger was much in favour in cogeneration plants in the seventies to nineties because of their compactness and high efficiency. They were, however, found to be rather heavy in maintenance. The second drawback was that the high corrosion resistance plate materials required were only able to withstand a relatively moderate pressure difference between primary and secondary heat exchanger media. Thirdly the plate seals tended to degenerate fairly fast and stick tenaciously to the plates making removal difficult without damaging the seals. The seals that were needed to withstand the required temperature and pressure were also pricy and not always in stock with the suppliers. This has led most plant operators to change over to and new plant designers to select the shell and tube configurations, which demand less maintenance and are easy to clean though requiring more room.

In low-temperature binary power plants shell and tube heat exchangers are used to transfer the heat from the geothermal primary fluid to the secondary (binary) fluid. They are also used as condensers/and or regenerators in the secondary system.

In supercritical geothermal power generation situation it is foreseen that shell and tube heat exchangers will be used to transfer the thermal energy of the supercritical fluid to the production of clean steam to power the envisaged power conversion system. In all instances it is very important to select tube and/or plate material in contact with the geothermal fluid that will withstand the temperature, pressure and corrosion potential of the fluid. Some Inconel, titanium and duplex stainless steel alloys have given good service. It is also important to make space allowance for tube withdrawal for maintenance and/or tube cleaning procedures. High pressure water-jet cleaning has for instance proved its value.

Scaling will normally be present. Provisions should therefore be made timely for scale abatement such as by hydrothermal operation by not allowing the geothermal water to become supersaturated with silica or chemical scale inhibitor injection, and/or mechanical cleaning.

4.7 Gas evacuation system

As previously stated the geothermal steam contains a significant quantity of non-condensable gas (NCG) or some 0.5% to 10% by weight of steam in the very worst case. To provide and maintain sufficient vacuum in the condenser, the NCG plus any atmospheric air leakage into the condenser must be forcibly exhausted. The following methods are typically adopted, viz.:

- The use of a single or two stage steam ejectors, economical for NCG content less than 1.5% by weight of steam;
- The use of mechanical gas pumps, such as liquid ring vacuum pumps, which are economical for high concentration of NCG; and
- The use of hybrid systems incorporating methods 1 and 2 in series.

The advantages of the ejector systems are the low maintenance, and high operational security of such systems. The disadvantage is the significant high-pressure steam consumption, which otherwise would be available for power production.

The advantages of the vacuum pumps are the high degree of evacuation possible. The disadvantage is the electric ancillary power consumption, sensitivity to particulate debris in the condenser, and high maintenance requirements.

To reduce the ambient level of H_2S in the proximity of the power plant, the exhausted NCG is currently in most countries discharged below the cooling tower ventilators to ensure a thorough mixing with the air as it is being blown high into the air and away from the power plant and its environs. In the USA, Japan and Italy H_2S abatement is required to meet air quality criteria, and in Italy also mercury (Hg) and thus require chemical type abatement measures.

In some of the older Geysers field power plants the H_2S rich condenser exhaust was passed through a bed of iron and zinc oxide to remove the H_2S. These proved a very messy way of getting rid of the H_2S and were mostly abandoned after a few years. In a few instances the Stretford process and other equivalent ones have been used upstream of the power plant to convert H_2S gas into sulphur for industrial use. This has proved expensive and complex and is not in use in other geothermal fields than the Geysers field in California.

The main H_2S abatement methods currently in use worldwide are (only some are currently used for geothermal NCG):

- AMIS process of ENEL;
- Claus (Selectox);
- Haldor Topsöe – WSA process;
- Shell-Paques Biological H_2S removal process/THIOPAC;
- LO-CAT (wet scrubbing liquid redox system);
- Fe-Cl hybrid process;
- Aqueous NaOH absorbent process;
- Polar organic absorbent process;
- Photo catalytic generation process;
- Plasma chemical generation process;
- Thermal decomposition process; and
- Membrane technology.

4.8 Re-injection system

In most geothermal areas the geothermal fluid may be considered to be brine because of the typically high chloride content. It may also contain some undesirable tracer elements that pose danger to humans, fauna and flora.

In considering the most convenient way of disposing of this liquid effluent other than into effluent ponds on the surface, the idea of injecting the liquid effluent back into the ground has been with the geothermal power industry for a long time (Stefánsson, 1997). Initially the purpose of re-injection was simply to get rid of the liquid effluent in a more elegant way than dumping it on the surface, into lakes or rivers, and even to the ocean. Many technical and economic drawbacks were soon discovered. The more serious of these were the clogging up of injection wells, injection piping and the formations close to the borehole; the cold effluent migrated into the production zone so reducing the enthalpy of the well output with consequent fall-off in power plant output. Injection into sandstone and other porous alluvial formations was and is fraught with loss of injectivity problems that are still not fully understood.

Soon, however, it became generally understood and accepted that returning the effluent liquid back into the reservoir had even greater additional benefits, viz.:

- Greatly reducing the rate of reservoir pressure and fluid yield decline;
- Improved extraction of the heat content contained within the reservoir formations; and
- Reducing the fluid withdrawal effect on surface manifestations, e.g. hot pools, steam vents etc.

All the above items serve to maintain resource sustainability and are thus of significant environmental benefit.

Re-injection should be considered an integral part of any modern, sustainable and environmentally friendly geothermal utilization, both as a method of effluent water disposal and to counteract pressure draw-down by providing artificial water recharge (Stefánsson, 1997). Re-injection is essential for sustainable utilization of virtually closed and limited recharge geothermal systems. Cooling of production wells, which is one of the dangers associated with re-injection, can be minimised through careful testing and research. Tracer testing, combined with comprehensive interpretation, is probably the most important tool for this purpose.

Many different methods have and are still being tried to overcome these technical problems mentioned above such as the use of settling tanks that promote polymerisation of the silica molecules and settling in the tanks prior to injection; injection of the effluent liquid directly from the separators at temperatures in the range of 145–160°C, so called "hot injection", both to avoid contact with atmospheric air and to hinder scaling in the injection system; controlling the pH of the effluent commensurate with reduction in the rate of silica/calcite precipitation using acids and add condensate from the plant to dilute the silica in the brine, to name a few. The danger of production well cooling can be minimised through careful testing and research. Tracer testing, combined with comprehensive interpretation, is probably the most important tool for this purpose. One way to delay the effects of cooling is also to locate the re-injection wells far enough away from the production area, say 2 km. Another way gaining popularity is to inject deep into the reservoir, even where there is small permeability, by pumping at high pressures (60–100 bar).

Surface disposal contravenes the environmental statutes of most countries and the use of settling tanks has ceased mostly because of associated cost and complexity. The most commonly adopted injection methods are the last two, i.e. hot re-injection and chemical pH control ones. The main disadvantage of the hot re-injection technique is the lowered overall thermal efficiency and the consequent greater fluid production (more wells to yield the same power output) required. The main disadvantage of the pH control scheme is the very large acid consumption (cost) and uncertainties regarding its long-term effects.

Hot re-injection is precluded in low-temperature power generation and the most common technique is to make use of the reverse solubility of calcite in water by operating the conversion system at a pressure level above the CO_2 bubble point and only reduce the pressure once the fluid temperature has attained a level low enough to prevent calcite dissipation prior to re-injection.

4.9 Chemical injection system

Chemical injection systems are sometimes applied for production and reinjection wells as wells as the the surface equipment to reduce scaling, corrosion and for ph-control.

Calcite scaling is common in production wells tapping liquid dominated reservoirs of 220-250°C. In order to reduce or prevent the calcite scaling in these wells a scale inhibitor is injected through a capillary tubing down hole. Similar injection is applied with caustic soda to neutralize acid wells to reduce the corrosivity. Acid is used for pH modification in order to arrest the scaling of silica in waste water going to reinjection, for cases where the water is supersaturated. Chemical control of pH by caustic soda and of biofilms is also applied to the cooling water (turbine condenser/cooling towers).

5. POWER PLANT DESIGN PARAMETERS

The most important power plant design parameters are:

- **Resource**
  1. Steam conditions: Optimum turbine inlet steam pressure. Gas (% NCG) in steam.
  2. Size (thickness and areal extent), and long term capacity, and natural recharge.
  3. Temperature and pressure of deep resource fluid.
  4. Chemical composition (liquid and gas phase) of deep fluid.
  5. Geology, stratigraphy, lithology and geothermal reservoir properties (faults, fractures, formation porosity, mineral alteration types and age, type of permeability).
  6. Reservoir permeability.
  7. Thickness of production/injection zones.
  8. Well productivity/injectivity.
  9. Two phase zones.
  10. Reservoir response to production/injection.
  11. Natural state modelling, computer simulation of reservoir, and model predictions.
  12. Reservoir monitoring and management.
- **Accessibility**
  1. Topography of resource area.
  2. Remoteness from population centres.
  3. Closeness to nature parks and environmentally restricted areas.
- **Market**
  1. Size, type and security of market.
  2. Proximity of market.
  3. Accessibility to existing power transmission lines, substations.
- **Permits etc.**
  1. Resource concessions.
  2. Exploration permits.
  3. Drilling permits.
  4. Development permits.
  5. Environmental Impact Assessment.
  6. Building and other permits.
- **Pre and post investment studies, business plan**

All the above parameters are important to the development plan, production and injection well drilling and well design. They are no less important in the selection of power plant type, siting of power station, production and injection well siting arrangement (well spacing, etc.), production and injection well numbers etc. It also plays a key-role in planning development increment size and timing.

Early information of resource fluid liquid and gas phase chemical composition is extremely important since it affects most component design, materials selection, types of components selected etc.

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