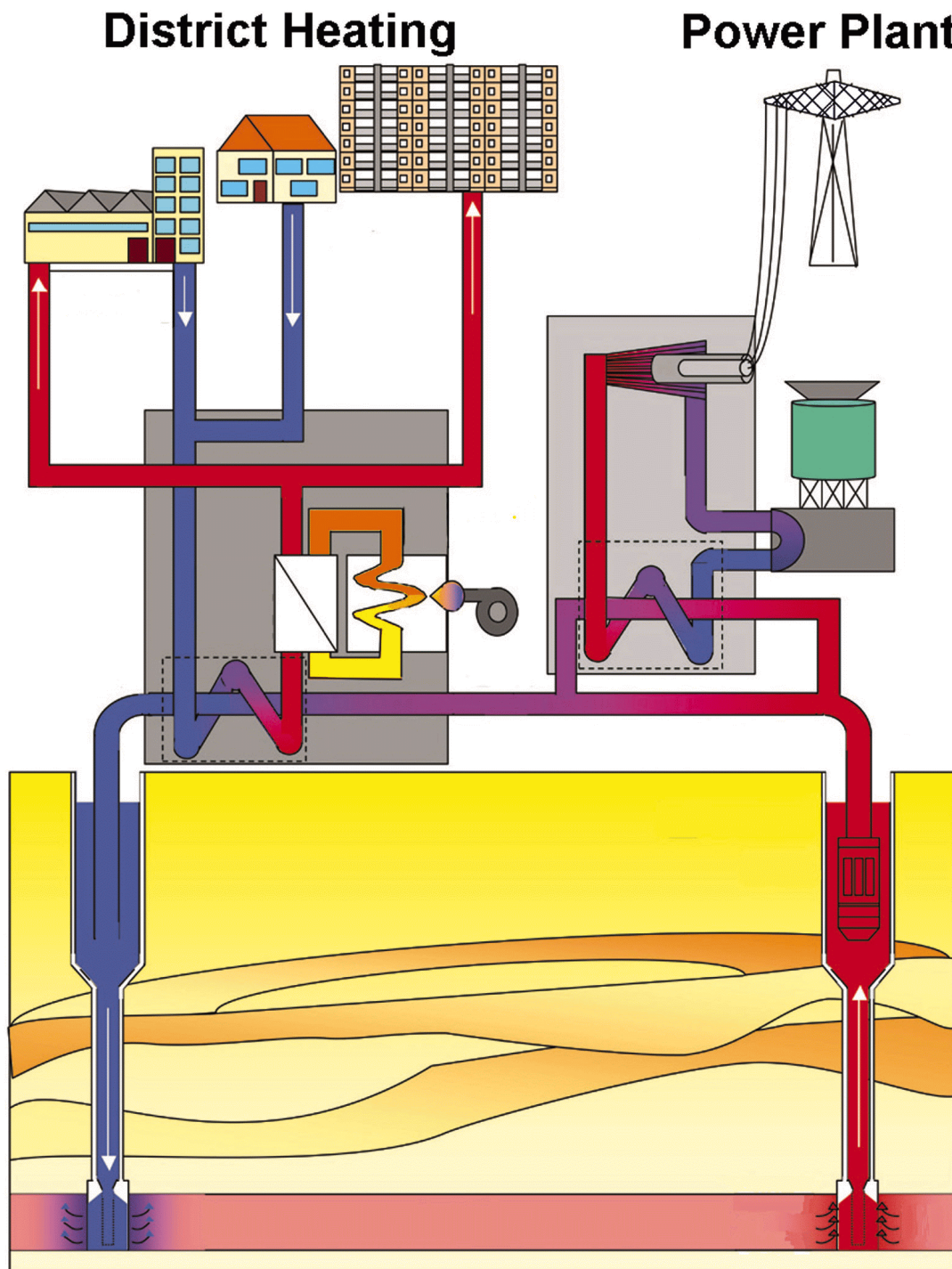


**GEO-HEAT CENTER***Quarterly Bulletin*

OREGON INSTITUTE OF TECHNOLOGY -KLAMATH FALLS, OREGON 97601-8801

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**Combined Geothermal Heat & Power Plants**

GEO-HEAT CENTER QUARTERLY BULLETIN

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**A Quarterly Progress and Development Report
on the Direct Utilization of Geothermal Resources**

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Cover: Modified schematic of the Neustadt-Glewe, Germany, combined heat and power plant (courtesy of Geothermische Vereinigung).

COMBINED GEOTHERMAL HEAT AND POWER PLANTS

Combined heat and power (CHP) plants are not a new use of energy, whether it be from conventional fossil fuels or geothermal. However, what has been happening recently in the geothermal arena is the use of low-temperature resources (down to 98°C or 208°F) in combination with binary or Organic Rankine Cycle (ORC) power units. Two installations, one in Australia at Birdsville and one in Germany at Neustadt-Glewe, both reported in this issue of the *Quarterly Bulletin*, are using temperatures this low—the lowest currently operating in the World!! However, there was an even lower temperature use at Paratunka, Kamchatka, Russia; a binary power plant using 81°C or 178°F producing 680 kWe and the wastewater used for heating the soil and water plants in greenhouse, was in operation for a number of years in the late 1960s and early 1970s.

This issue of the *Quarterly Bulletin* reports on high temperature CHP installations in Iceland at Svartsengi and Nesjavellir, and low-temperature installations in Iceland at Husavik, in Austria at Bad Blumau and the two mentioned above in Australia and Germany. We took some liberty in interpreting the CHP description, as the Birdsville installation, after producing electric energy uses the spent fluid for domestic drinking water and for stock watering, and not for space heating. We also know of CHP plants elsewhere in world, described below.

However, first a little background. Why CHP?? The main reason is that it makes more efficient use of the resource by cascading the temperature (energy use), which in turn improves the economics of the entire system. Low-temperature power generation alone is often not economical below 150°C or 300°F as the net plant efficiency for ORC units varies from 12% down to 7% (to 90°C or 194°F) (see a paper by Kevin Rafferty on Geothermal Power Generation on the GHC website). One of the exceptions in the U.S. is at Wineagle in northern California using 110°C or 230°F resource; however, this plant has no pumping cost and disposes the spent fluid to the surface. There are several other stand-alone ORC plants in the United States and elsewhere in the world using low-to- moderate temperature geothermal resources (*GHC Quarterly Bulletin*, Vol. 20/2–March 1999). Many CHP plants, especially those using a low-temperature resource, started as just a district heating project. The electric power plant was later added, and became economical, as the well and pumping systems were already in place. All the power plant designers/ operators did was take some temperature off the top, yet still providing enough temperature (energy) for the district heating system.

This cascaded use of geothermal energy in the form of CHP plants has been described in previous issues of the *GHC Quarterly Bulletin*, and thus, is not reproduced here, but is summarized below:

- **Empire Energy** in northwest Nevada, where the heat is cascaded to an onion/garlic dehydration plant and also planned to be used for fish raising (see article by R. G. Bloomquist – “Empire Energy, LLC – A Case Study,” Vol. 25/2, 2004).
- **Altheim, Austria** using 106°C or 223°F to operate an approximately 500-kWe plant and providing heat to about 650 consumers (see article by G. Perneckner and S. Uhlug – “Low-Enthalpy Power Generation with ORC-Turbogenerator—The Altheim Project, Upper Austria,” Vol. 23/1, 2002).
- **Suginoi Hotel, Beppu, Japan** using 143°C or 289°F to operate a 3-MWe condensing steam turbine and supplying the waste fluid to the hotel for space heating and baths. (see article by K. Kudo – “3,000 kW Suginoi Hotel Geothermal Power Plant,” Vol. 17/2, 1996).
- **Hatchobaru, Japan** using 106°C or 223°F from the condenser of the Hatchobaru power plant (2x55 MWe) for heating a demonstration greenhouse (see article by P. Lienau – “Geothermal Greenhouses in Kyushu, Japan,” Vol. 17/2, 1996).
- **Fang, Thailand** using 116°C or 241°F to operate a 300-kWe ORC plant and the waste water then cascaded for use at a refrigeration (cold storage) plant, crop drying and a spa (see article by J. Lund and T. Boyd – “Small Geothermal Power Project Examples,” Vol. 20/2, 1999).
- **Mt. Amiata, Italy** using 184°C or 363°F steam to operate a 15-MWe condensing plant and the waste water piped to 22 hectares (54 acres) of greenhouses and for a vegetable dehydration plant (see article by J. Lund – “Cascading of Geothermal Energy in Italy,” Vol. 10/1, 1987).
- **Palinpinon, Philippines** using 160°C or 320°F fluid from the Palinpinon I steam gathering system, where 192 MWe are produced. The steam is passed through a shell-and-tube heat exchanger and the 154°C or 309°F fluid is used in a drying plant producing copra (dried coconut meat) (see article by S. Chua and G. Abito – “Status of Non-Electric Use of Geothermal Energy in the Southern Negros Geothermal Field in the Philippines,” Vol. 15/4, 1994).
- **New Zealand: at Broadlands**, the Ohaaki power plant provides steam to dry alfalfa (Lucerne); **at Wairakei**, the power plant provides waste heat for 19 giant Malaysian freshwater prawns ponds; and **at Taupo**, the power plant operated by Mercury Geotherm provides steam to a greenhouse, where orchids are raised (see *GHC Bulletin*, Vol. 19/3, 1998 for details).
- **Los Azufres, Mexico** using condensate from the steam pipeline feeding a 50-MWe unit at about 170°C or 338°F for use in an experimental lumber drying kiln, a greenhouse and fruit dehydrator (see article by J. Lund – “Design of a Small Fruit Drier Using Geothermal Energy,” Vol. 17/1, 1996) and the companion article in the GRC Transactions, Vol. 19 (1995) by E. Sanchez-Velasco and E. Casimiro-Espinoza – “Direct Use of the Geothermal Energy at Los Azufres Geothermal Field, Mexico” – pp. 413-415.

The Editor

INTEGRATING SMALL POWER PLANTS INTO DIRECT-USE PROJECTS

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Washington State University Energy Program

INTRODUCTION

Although generation of power from geothermal energy with small “wellhead generators” (i.e., units <5MWe) is not new, the past few years have seen an increased interest, application and research into this technology (see *GHC Bulletin*, Vol. 20, No. 2, 1999). As a result, there has been a considerable amount of work done on various working fluids including various Freon, organic fluids (e.g., propane, isobutene, etc.), ammonia, and interest and research into low-temperature flash is also on the rise.

Some existing units have now seen over 20 years of operation and although most earlier units were put online as stand alone plants, or as the first step in demonstrating the viability of a field prior to build out, recent work has been directed toward the development of combined heat and power projects that couple power production with direct-use applications. Recent projects in Austria, including the Rogner Hotel and Spa Eco-Resort in Bluman (Figure 1) and the geothermal district heating project in Altheim (Schochet and Legmann, 2002; Gaia 2002) are excellent examples of integrated projects designed to both provide power and supply space heating (see article in this *Bulletin*).

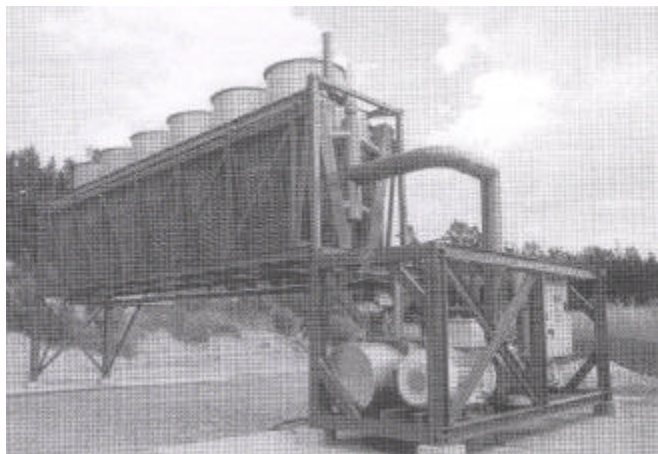


Figure 1. *Series 250 ORMAT Energy Converter Power Unit at Bad Bluman (Schochet & Legmann, 2002).*

One of the most interesting recent developments in the use of small wellhead-type generation is the coupling of such systems to agribusiness (e.g., agriculture crop dehydration, alcohol distillation, greenhouses and aquaculture).

HISTORY

The advent of small power plants dates to the very beginning of geothermal power production. The first plant

dates back to 1904 when Prince Piero Ginori Conti first used geothermal energy to power 10-kWe reciprocating engine to drive a small generator in order to provide lighting to his boric acid factory in Larderello, Italy (Lund, 2004).

The first commercially produced geothermal power was also generated at Larderello; when in 1914, a 250-kWe unit began providing power to the cities of Volterra and Pomarance.

In the early-1900s, the first small geothermal power plant in the United States went online at The Geysers in northern California. This 35-kWe unit provided power to the local resort, and a few, if any, could imagine at the time that The Geysers geothermal field would someday be the largest producer of geothermal power in the world.

In 1967, an experimental binary power plant was commissioned at Paratunka, Kamchatka, Russia (Lund and Boyd, 1999). This small 680-kWe power plant used 81°C (178°F) geothermal water and although it is considered to be one of the earliest binary power plants, it is interesting to note that the first commercial geothermal power plant at Larderello were also, in fact, binary-type plants. At Larderello, the geothermal steam was used to evaporate clean water to power steam turbines; thus, avoiding the corrosion effects related to the use of the geothermal steam directly (DiPippo, 1999).

By the early-to-mid 1980s, small binary plants had been demonstrated to be economically viable in a number of locations and by the mid-1990s, commercial plants were located throughout the western U.S., and throughout much of the world. Small flash plants have also proved their commercial viability and can be found in such diverse countries as Iceland, Mexico, Japan, Portugal (Azores) and Ethiopia to name but a few (Lund and Boyd, 1999).

TECHNOLOGIES

The vast majority of small geothermal power plants are either binary or flash; although, some are a hybrid of both, and even dry steam has been used in at least one application. Both flash steam and binary technologies have their own proponents, and each has its own set of advantages and disadvantages.

Flash Steam Plants

In a flash steam plant (either single or double flash), the two-phase flow from the well is directed to a steam separator; where, the steam is separated from the water phase and directed to the inlet to the turbine. The water phase is either used for heat input to a binary system in a direct-use application, or injected directly back into the reservoir (Figure 2).

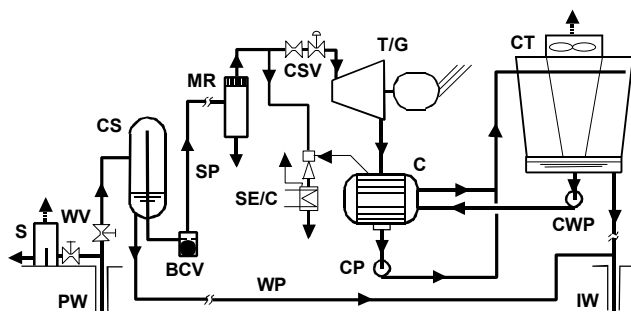


Figure 2. *Simplified flow diagram for a single-flash geothermal power plant (DiPippo, 1999).*

The steam, after passing through the turbine, exits into the condenser; where, it is cooled via water from the cooling tower. Historically, flash has been employed where resource temperatures are in excess of approximately 150°C (300°F); however, studies completed by Barber Nichols Inc. of Arvada, Colorado (Forsha, 1994) would seem to indicate that flash technology could be employed at temperatures as low as 120°C (250°F) or less, and at a cost significantly lower than that of a similarly sized binary plant. Cost savings are attributable to cost differences in the heat addition and heat rejection systems of the two competing technologies. Examples of small flash plants can be found in, for example, Japan and Guadalupe.

In Japan, a small flash facility was installed at the Kirishima International Hotel in Beppu, Kyushu in 1983. The 100-kWe non-condensing unit operates on the output of two production wells and has an inlet temperature of 127°C (261°F) at 2.45 bar (35.5 psi). Electricity is used for base load in the hotel and provides 30-60% of the load depending upon season and time of day. Hot water from the separator is used for outdoor bathing, space heating and cooling, domestic hot water heating of a sauna bath, and for two indoor baths (Lund and Boyd, 1999).

On the Island of Guadalupe, the Bouillante geothermal flash condensing power plant was put online in 1986 with the plant being modernized and several improvements made in 1995 and 1996 (Correia, et al., 1998). Improvements included installation of three automated controllers to monitor all plant activity and manage operations. The plant is a double-flash plant based on a geothermal resource of approximately 200°C (392°F). Steam pressure from the two separators are six and one bar (87 and 15 psi), respectively. Cooling is through the use of seawater in a direct-contact heat exchanger.

Binary Plants

In a binary plant (Figure 3), the thermal energy of the geothermal fluid is transferred to a secondary working fluid via a heat exchanger to use in a conventional Rankine Cycle, or alternatively Kalina Cycle (Figure 4). The vaporized working fluid (e.g., isopentane, propane, Freon or ammonia) drives the turbine before being condensed and returned to the heat exchanger in a closed loop. Cooling is generally provided through the use of air coolers; although, some work

on evaporatively enhanced air cooling is ongoing (Sullivan, 2001) and could result in efficiency improvements of 5% or more during summer periods.

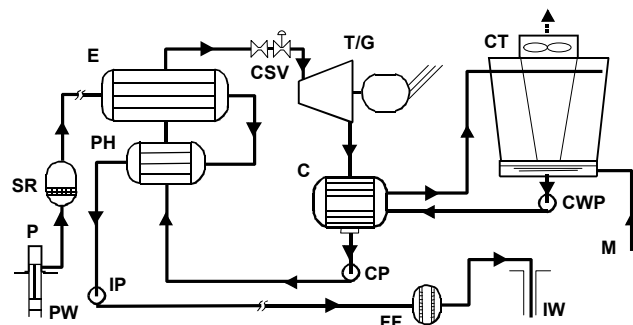


Figure 3. *Simplified flow diagram for a basic binary geothermal power plant (DiPippo, 1999).*

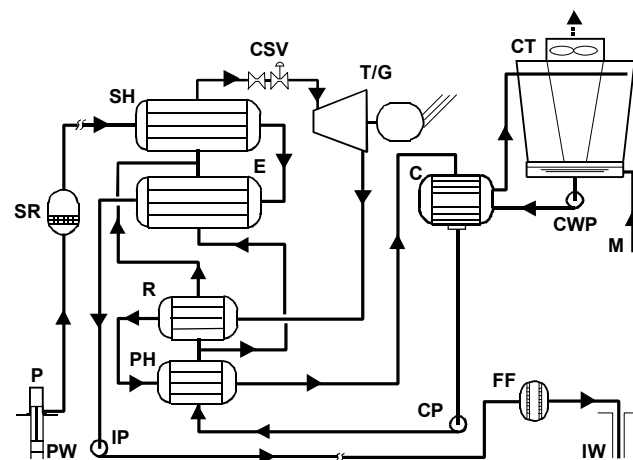


Figure 4. *Simplified flow diagram for a Kalina binary geothermal power plant (DiPippo, 1999).*

Examples of small binary plants are found, for example, in the United States and Austria. The Wineagle and Amedee power plants are located near the shore of Honey Lake in northern California. The Wineagle power plant went online in 1985, and consists of two binary units of total gross output of 750-kWe and a net output of 600-kWe. The Amedee plant is composed of two units of one-MWe each and has a net output of 1.5 MWe. Resource temperatures are relatively low, 110°C (230°F) at Wineagle and 104°C (219°F) at the Amedee plant, and flow rates are 63 L/s (1000 gpm) and 202 L/s (3200 gpm), respectively. The plants were designed to operate on Freon 114, but since then, the Wineagle plant has been converted to operate on isobutene (Nichols, 2003). Both plants have operated with an availability of over 90% and a capacity factor that has at times exceeded 100% of name plate. The plants are fully automated and are designed to operate unmanned and to go through a self-start procedure if tripped off line due to a transmission line failure. The plants can be monitored and started remotely if required.

The Altheim, Austria binary plant is a 1-MWe net output facility designed to operate on 86 L/s (1360 gpm) of 106°C (223°F) geothermal water. The plant is water cooled. The plant uses a special high molecular mass organic compound as the working fluid. According to Gaia (2002), the working fluid is non-flammable, non-corrosive and has no ozone depletion activity. The turbine uses variable geometry nozzles that were specifically designed to maintain high efficiency at partial load, and the nozzles variable geometry allows the turbine to be adapted to meet various geothermal and cooling water flow rates. The unit includes a programmable logic controller that allows for remote monitoring and control, with the only exception being during startup. The outlet temperature of the geothermal fluid from the unit is 70°C (158°F) and is used to provide heat to the Altheim district heating system.

GEOHERMAL POWER GENERATION AND AGRIBUSINESS INDUSTRIES

The development of agribusiness/power projects has become one of the fastest growing areas of interest for low-temperature geothermal development (i.e., <150°C [300°F]). As early as the beginning of the 1980s, however, the first agribusiness/power plant project was initiated in Nevada at Wabusca. The project consists of an alcohol distillation plant and two small <1-MWe Organic Rankine Cycle generators. Cooling was provided through the use of a spray cooling pond. Unfortunately, the alcohol distillation facility was shut down shortly after it went into production due to a lack of feed stock. The power plant has continued in operation, and despite the premature demise of the distillation plant, proved the viability of the concept.

In the spring of 2000, the National Renewable Energy Laboratory (NREL) issued a request for the construction of small-scale (300-kWe to 1-MWe) geothermal power projects and five projects were selected for funding. Of these, three have reached agreements with NREL and projects are going through preliminary stages of design. The purpose of the program is to better establish the economic viability of small power plants through documentation of capital cost, system performance, and operation and maintenance requirements over a three-year test period in different regions of the United States. All three of the projects incorporate power production into already existing agriculture facilities. The three projects are Empire Energy in Empire, Nevada; Milgro - Newcastle in Newcastle, Utah and AmeriCulture near Cotton City, New Mexico (Kutscher, 2001).

AmeriCulture

The AmeriCulture project involves the design, installation, operation and monitoring of a 1.42-MWe gross (abt. 1-MWe net) water-cooled Kalina Cycle geothermal power plant using ammonia-water as the working fluid. The project is located near Cotton City, New Mexico, south of Lordsburg.

The plant (Figure 5) will supply electricity to the AmeriCulture fish hatchery. Geothermal fluid will be pro-

vided from an existing 120-m (400-ft) production well producing approximately 63.1 L/s (1000 gpm) of approximately 115-120°C (240-250°F) brine from the Lightning Dock geothermal resource. The “waste heat” from the power plant will be used to heat tanks used for the rearing of tilapia for sale to aquaculture farms that raise the tilapia for market. The estimated cost of the project is \$3,370,000 (Kutscher, 2001).

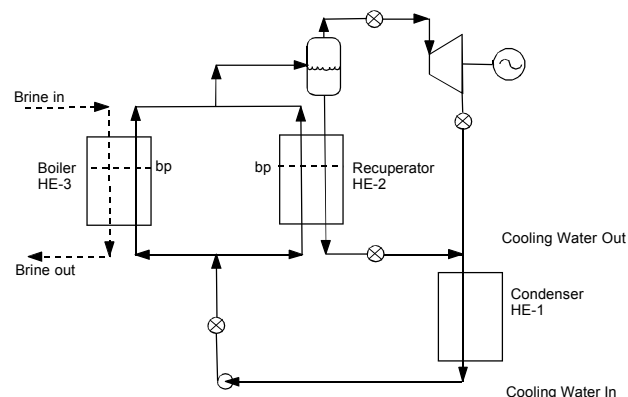


Figure 5. *Energy/AmeriCulture Kalina Cycle schematic (Kutscher, 2001).*

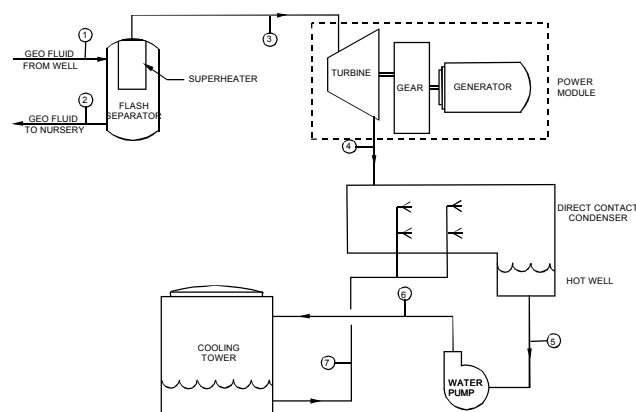


Figure 6. *Milgro-Newcastle low-pressure flash system schematic (Kutscher, 2001).*

Milgro-Newcastle

The Milgro-Newcastle project is located some 240 km (150 miles) northeast of Las Vegas, Nevada, in Newcastle, Utah. The plant (Figure 6) is being designed as a low-pressure flash plant based on the estimated 135°C (275°F) geothermal resource widely available in the Escalante Valley. The 1-MWe gross plant will deliver approximately 705 kWe net to the Milgro nursery. The separated brine at about 92.5°C (198.5°F) will provide heat to the greenhouse complex at the Milgro nursery. The estimated total cost of the project is \$2,550,000 and includes \$400,000 for well development (Kutscher, 2001).

Empire Energy

The Empire project began in 1987 as a small power project built as a partnership between ORMAT and Constellation Energy. The initial project was based on an approximately 130°C+ (266°F+) resource and generated about 3.6 MWe (Figure 7).



Figure 7. Binary power plant in Empire, Nevada.

In 1994, Empire Farms built an onion and garlic dehydration plant (Figure 8). The dehydration plant is capable of drying approximately 40,000 tons of product per year. In 1997, Empire Energy, a subsidiary of Empire Farms took over the initial power plant and wells drilled for the dehydration plant began supplying the power plant in addition to meeting the requirements for dehydration.



Figure 8. Onion and garlic dehydration plant.

The new wells produced geothermal fluids at approximately 147°C (297°F) from between 500-650 m (1640-2130 ft) depth.

The proposed new facility (Figure 9) is being designed to use water cascaded from the dehydration plant at about 120°C (250°F) flow of approximately 75 L/s (1190 gpm).

The plant is being designed to produce a minimum of 1.2 MWe for sale to Empire Foods, L.L.C. The plant had originally been designed to demonstrate the benefits of

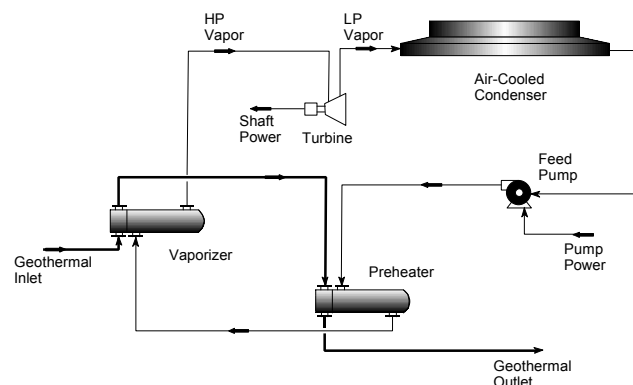


Figure 9. Empire Energy binary-cycle system schematic (Kutscher, 2001).

evaporatively enhanced dry cooling, but because this has already been successfully demonstrated at a plant in California (Sullivan, 2001), the decision was made to revise the design to incorporate variable concentrations of mixed working fluids to best achieve optimum operational efficiency and to use water cooling (Green, 2003).

The estimated total cost of the project was initially \$2,555,000 (Kutscher, 2001). This cost is at present being recalculated, taking into account the modification in design noted above. This will be an extremely interesting project to follow, as unlike the design of most agribusiness/power plant projects, the Empire project will use water cascaded from the dehydration plant rather than using the highest temperature resource for power production (i.e., a bottoming cycle).

SUMMARY

The integration of power production and agribusiness projects can significantly improve the economic viability of using lower temperature geothermal fluids and can result in a much higher overall “fuel use efficiency” than can be achieved with stand-alone power or direct-use projects. Validation of the economic, performance, and operation and maintenance requirements of these facilities should be a major step in encouraging the replication of such projects worldwide.

NOMENCLATURE FOR PLANT FLOW DIAGRAMS (Figures 2, 3 and 4)

BCV - ball check valve	C - condenser
CP - condensate pump	CS - cyclone separator
CSV - control and stop valve	CT - cooling tower
CW - cooling water	CWP - cooling water pump
E - evaporator	F - flasher
FF - final filter	IP - injection pump
IW - injection wells	M - make-up water
MR - moisture remover	P - well pump
PH - preheater	S - silencer
SE/C - steam ejector/condenser	SH - superheater
SP - steam piping	SR - sand remover
T/G = turbine/generator	TV - throttle valve
WP - water piping	WV - wellhead valves

ACKNOWLEDGMENT

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HÚSAVIK ENERGY

MULTIPLE USE OF GEOTHERMAL ENERGY

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INTRODUCTION

Húsavík is the largest town in Northeast Iceland with a population of around 2,500 inhabitants. Húsavík has been an active trading post since 1614 and the town's economy has since that time mainly been based on fishing, fish processing and service for the surrounding countryside. However, tourism and other industries have played an increasing role during recent years. The main natural resources of the Húsavík area are plentiful fishing waters, geothermal heat and an abundant supply of fresh, cold water.

In 1969, Fjarhitun hf. Consulting Engineers carried out a feasibility study for a geothermal district heating system in Húsavík. The outcome of the study was that the most economical way to construct such a district heating system was to utilize hot water from springs at Hveravellir, 20 km south of Húsavík. The chemical composition of the water at Hveravellir allows direct use, unlike the water from the wells that had been drilled in Húsavík the previous years. The construction of a pipeline from Hveravellir to Húsavík began in the spring of 1970. At the end of that same year, all houses in Húsavík had been connected to the geothermal district heating system.

Initially the district heating system used 100°C hot water directly from the springs, but in 1974 a 450-m deep well, H1, was drilled. Well H1's production was approx. 40 L/s of 128°C hot water, in addition to the 43 L/s that the springs produced. The utilization of the 83 L/s available was divided between the greenhouses in Hveravellir which received 9 L/s and Húsavík which received 74 L/s, used for the town's swimming pool and its district heating system.

Despite the temperature of the water from H1 being at 128°C, utilization was limited to water at a lower temperature or 100°C. Approximately 2.2 kg/s of steam was lost to the environment when the geothermal fluid was separated at atmospheric pressure. As stands to reason a lot of energy was lost during this process. Losses were also incurred on the way from Hveravellir to Húsavík, the water traveling the 18 km distance through an uninsulated, subsurface, asbestos-reinforced cement pipe. On the way the water lost 15°C, arriving in Húsavík at a temperature of 85°C. The elevation difference between Húsavík and Hveravellir is around 100 m, Húsavík being the lower area, so no pumping was needed.

Demand continued to increase so a new borehole, H10, was drilled at Hveravellir in 1998. Well H10 turned out to be quite productive, today providing approx. 60 L/s of 124°C water at 2 bar (0.2 MPa) pressure.

Preparations for the renewal of the asbestos-reinforced cement pipe between Hveravellir and Húsavík began in 1998. Since the geothermal water at Hveravellir is hot enough for both industrial use and district heating needs, the idea to aim simultaneously for multiple or cascade use of the resource developed. A complete revision of the system was decided upon, to be based on the following objectives:

- Ensure sufficient energy at all times for all customers of Húsavík Energy.
- Ensure an appropriate temperature of water for each customer's need.
- Increase efficiency in utilization of the geothermal energy.
- Improve the variety of geothermal energy use.
- Use the geothermal energy, as well as the abundant supply of fresh cold water to attract new customers and strengthen the industrial society in the area of Húsavík.

Orkuveita Húsavíkur (Húsavík Energy) applied for a grant from the fourth framework program of the European Union. The application was based on the project's demonstrative characteristics regarding innovative multiple use of geothermal energy. The project was granted €663,000 (approximately \$860,000).

The project was completed in 2001 and a final report sent to the European Union, which has accepted the report without comment.

This report highlights the project's major elements as well as its progress.

THE GEOTHERMAL FIELD

The geothermal energy at Hveravellir has long been utilized in neighbouring greenhouses and farms. Since Húsavík Energy began operating in 1970, withdrawal from the field has been monitored. An average 80-85 L/s of 100°-128°C hot water has been withdrawn from the field.

The National Energy Authority of Iceland published a report regarding the potential magnitude of the geothermal resource at Hveravellir in January 1998 (Orkustofnuns/GAX, 1998). The report states that the Hveravellir geothermal field is able to withstand withdrawal from boreholes amounting to at least 190 L/s of hot water.

Wells H17 and H18 were drilled in 1998 and provide a very poor flow of water, despite temperature readings of close to 130°C. Well H16 merely provides about 8 L/s of

115°C hot water. The National Energy Authority has stated that it's estimate of the geothermal field's potential is not in need of review, it is merely the matter of finding the correct drilling sites.

A decision to defer further drilling was made and thus to commence operation of the new district heating system using only the water available from wells H1, H10 and H16. Table 1 lists the performance of wells H1, H10 and H16 at 2.5 bara pressure into the supply main.

Table 1. Performance of wells H1, H10 and H16

Wells	Flow L/s	Temperature °C
Well H1	26	128
Well H10	61	124
Well H16	8	115
Wells H1 and H10	87	125
Wells H1, H10 and H16	95	124

GEOHERMAL SYSTEM

Changes in the Geothermal System

As stated in the introduction, the district heating system of Húsavík initially utilized 100°C surface flow from hot springs at Hveravellir. After well H1 had been drilled,

additional water at 100°C was provided into the system. Since water from the well is at 128°C, it had to be cooled down to 100°C by boiling at atmospheric pressure before entering the system. In the cooling process, 2.2 kg/s of steam was released into the atmosphere. The total supply from well H1 and hot springs was 83 L/s, all of which was covered by the local demand. The 100 m difference in height between Húsavík and Hveravellir, Húsavík being the lower spot, enables pure gravity flow of the medium all the way to Húsavík. Pumping in the district heating system was only required for the highest standing houses in Húsavík in addition to having to pump the hot water to the municipality of Aðaldalur. An estimated 70-80% of all flow to consumers required no pumping. Thus, the operational safety of the district heating system was high, the system was easily maintained and inexpensive to operate--resulting in one of the lowest energy prices in Iceland.

When the time came to renew the main supply pipe from Hveravellir to Húsavík and increase production, a strategic decision was called for--should the operating conditions that had worked well for three decades be left unchanged--or should a different setup with other goals, such as those stated in the introduction, be considered? The decision reached was to make changes necessary for full utilization of the heat available from the 124-128°C water. Figure 1 shows the main changes in the utilization of geothermal heat from Hveravellir that followed.

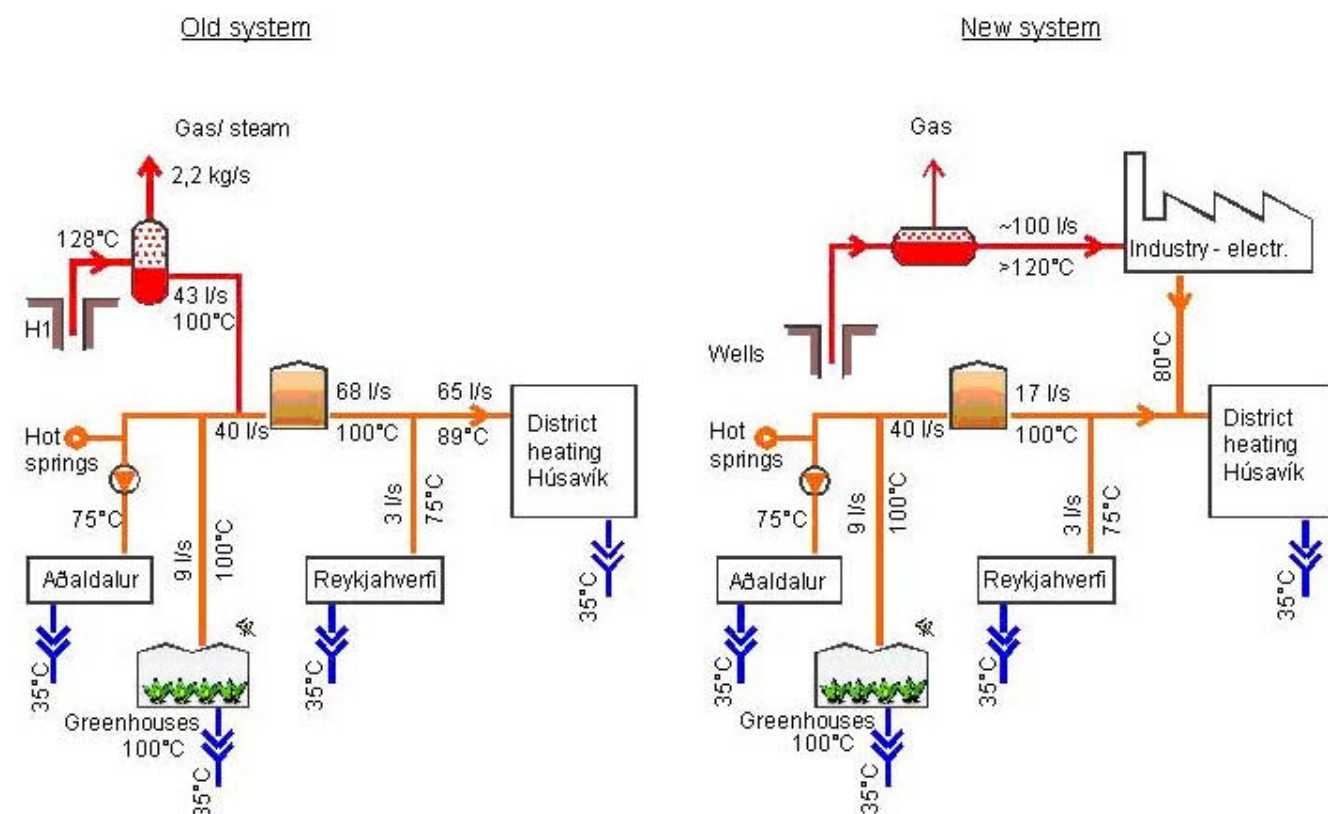


Figure 1. Improvements in utilization of geothermal heat.

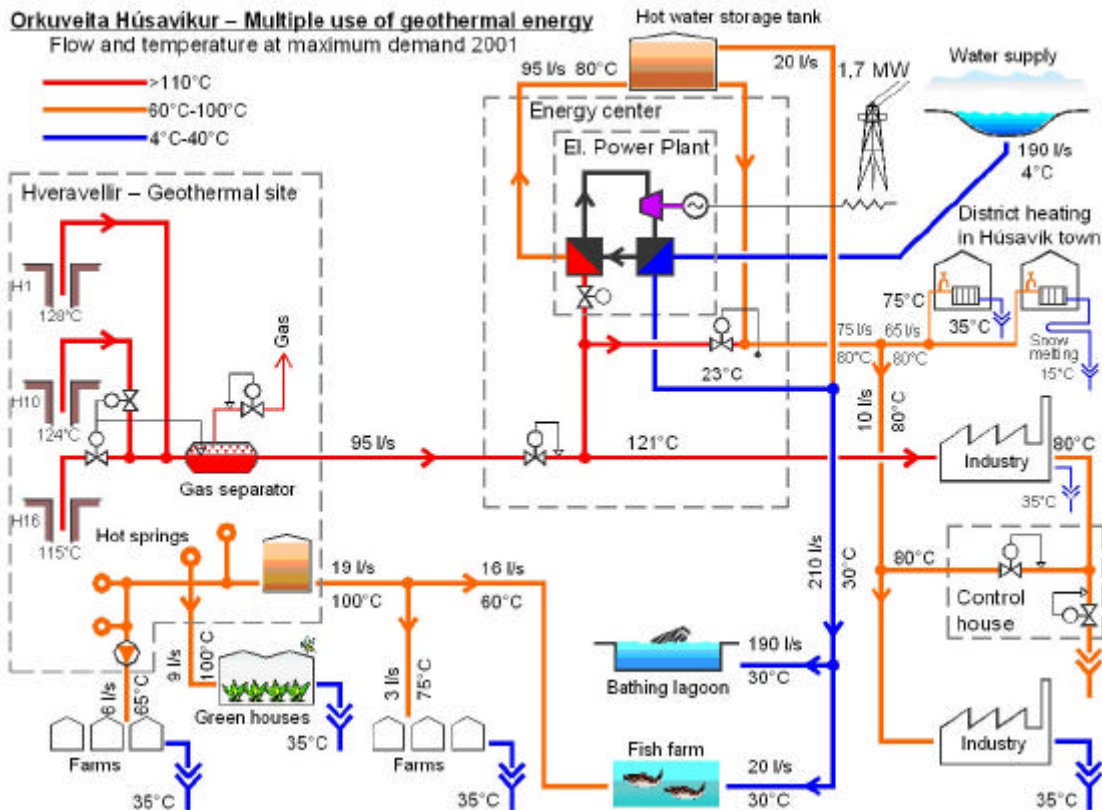


Figure 2. Húsavík Energy - multiple use of geothermal energy - process diagram.

The major change in the process is that the water now enters the supply pipeline to Húsavík directly, without prior cooling from 124°-128°C down to 100°C. This modification makes it possible to produce electricity or utilize the water for a variety of industrial purposes, before it enters the district heating distribution network in Húsavík.

New Geothermal System

Figure 2 shows the system diagram of the new district heating system. Included are the main components of the system and the utilization possibilities.

The system is very flexible. It allows for increased flow of 120°C water to industry, accomplished by decreasing electricity production. The flow of 80°C water to industry can also be increased when the demand for district heating in Húsavík decreases. In addition, flow to the bathing lagoon and to fish-farming can be controlled upon demand. Flow related values in Figure 2 indicate flow in the system at periods of maximum demand for district heating and electricity production in 2001.

Surface flow from the hot springs at Hveravellir supply the system with 34 L/s of 100°C water. This water is utilized in the same manner as before: in greenhouses in Hveravellir, for district heating in the countryside, and for fish-farming at Laxamýri. Water from the hot springs that is not utilized in this manner is led to Húsavík, where it is used for fish-farming and afterwards discarded into the Atlantic Ocean.

The water from geothermal wells H1, H10 and H16 is led into a gas separator at Hveravellir. The flow is controlled in such a way that the hottest well, H1, has a priority, then H10 and finally H16 is used upon demand.

The gas emitted from the gas separator is mostly nitrogen, N₂, in addition to small amounts of H₂S.

After leaving the gas separator the geothermal water enters a 16-km long pipe leading to the Energy Center located just south of Húsavík. During periods of maximum flow in 2001 the water temperature dropped by 3°C on the way, arriving at the Energy Center at 121°C. During periods of less flow, this cooling is increased somewhat but is partly counteracted by the water entering the pipe somewhat hotter at Hveravellir.

The flow of water into the Energy Center can be controlled within the following limits:

- From Hveravellir: 0 to 95 L/s of geothermal water at 121°C.
- From fresh water supplies: 0 to 200 L/s of fresh water at 4°C.

From Energy Center water can be delivered at temperatures ranging between 4°C - 121°C, for:

- Electricity production
- Industrial use
- District heating

- Fish-farming
- Bathing lagoon

Currently, all 121°C hot water is used to produce electricity. Water at 4°C is used as cooling water in the condenser. Should the market for industrial utilization of the water become more feasible, the production of electricity can be reduced and the water supplied to industry. The general policy of Húsavík Energy is however to continue full electricity production and drill additional wells if industrial demand increases.

The geothermal water is cooled from 121°C to 80°C in a heat exchanger after entering the Power Plant as described in the next section. From there the 80°C water enters a storage tank from which it flows, via the district heating supply main, through the Power Plant before entering the distribution network of Húsavík. The 80°C water in Húsavík is used for various purposes, namely for district heating, fish drying, fish farming, etc.

Power Plant

The role of the Power Plant in the system is twofold: to produce electricity and to cool the geothermal water to a temperature suitable to the district heating system.

The Power Plant operates under the so called Kalina-technique, which is based on a closed cycle in which a water and ammonia mixture ($\text{NH}_3\text{-H}_2\text{O}$) serve as the transfer medium (refrigerant). Unlike pure substances, which remain at a constant temperature during boiling or condensation, the mixture's temperature changes during these phase changes.

Once the transfer medium has been heated using geothermal water, it enters a separator, where liquid is separated from vapor. The vapour, rich with ammonia (NH_3), is then led through a turbine where it expands when pressure is decreased. The energy created during this process is turned into electricity in a generator connected to the turbine. The liquid separated from the gas in the separator, is used to preheat the returning mixture in recuperator 1. Following this the liquid is reunited with the vapor and is cooled down in recuperator 2. Before entering the condenser a second separator is installed separating the phases and the water is pumped through inlet nozzles into the condenser where the ammonia vapor is condensed.

The cooling water exits the condenser into an effluent pipeline that leads to a man-made bathing lagoon, located south of the Power Plant. On its way there, part of the cooling water is withdrawn from the pipeline and used in fish-farming.

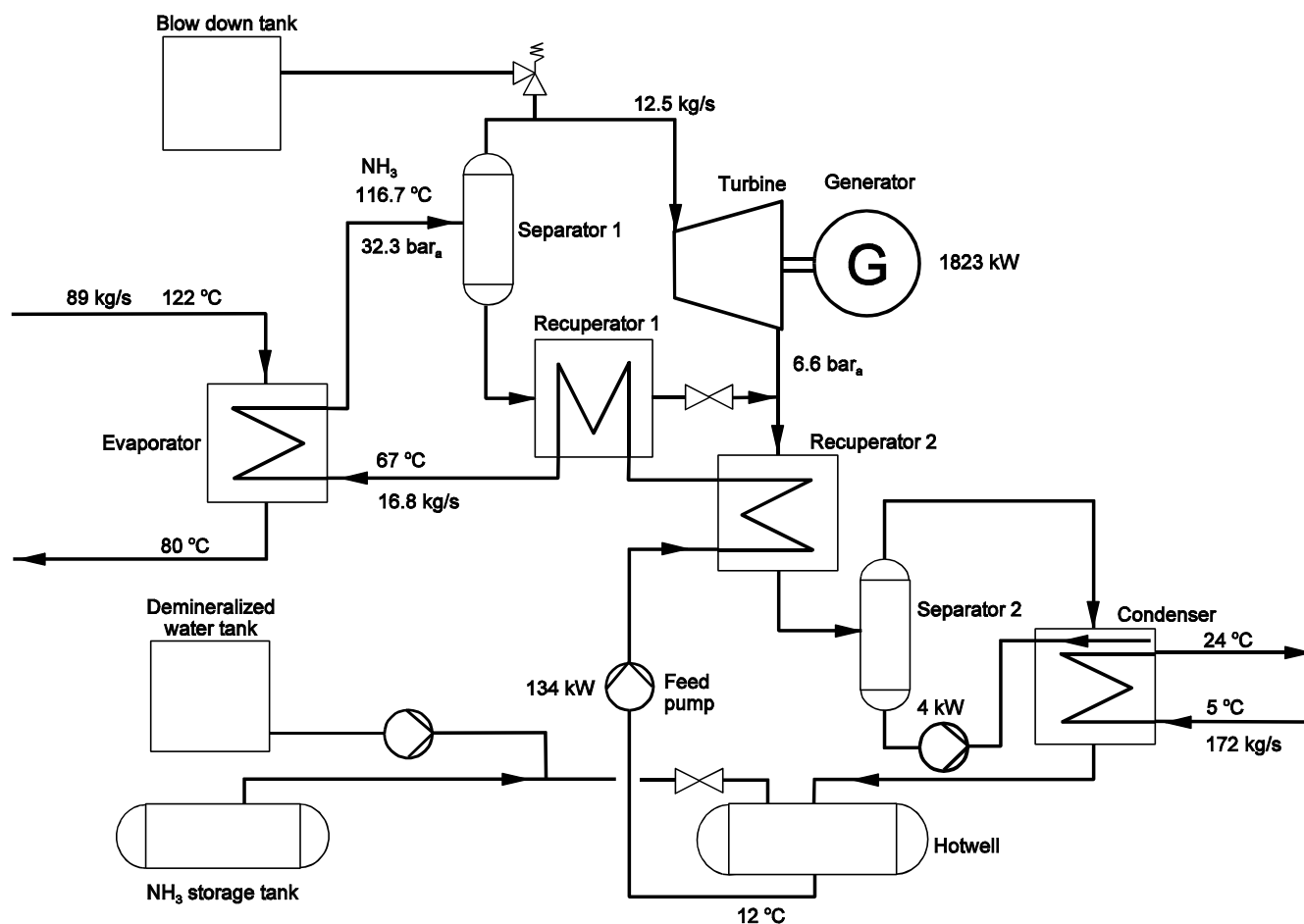


Figure 3. Power Plant – Schematic diagram.

A schematic diagram of the production cycle is shown in Figure 3. Initial design assumptions have been modified to reflect the actual geothermal characteristics encountered. All numbers in the diagram represent theoretical values based on the present conditions. The calculated output under the given conditions is some 7% less than theoretical calculations indicate. With proper selection of equipment the output can be calculated as high as 2,150 kW net as a recent offer from an expander manufacturer proves. During the final acceptance testing in November 2001 this output could not be reached but the acceptance certificate was issued as a result of an agreement with the contractor.

The Kalina-technique is recently developed and has never been applied to geothermal heat prior to the installation at Húsavík. Binary fluid systems are not new but the difference between the Kalina system and traditional versions lies in the type of transfer medium used in the closed electricity production cycle. As mentioned, the transfer medium in the Kalina cycle is a mixture of water and ammonia, while traditional ORC cycles use pentane. The difference between these two fluids while boiling, is that pentane boils at a constant temperature while temperature varies in a boiling water-ammonia mixture. This property of the transfer medium makes the efficiency of the Kalina cycle much better than that of a typical ORC cycle, given the conditions present at Húsavík.

UTILIZATION OF THERMAL POWER

As stated previously, much emphasis was assigned to obtaining flexibility within the Energy Center's operational system, thereby enabling the most feasible/economical usage of the thermal energy at all times. Currently the pillars of the operation are the district heating services it provides and the electricity production. These two operational functions provide the Húsavík Energy with most of its revenue. The industrial use of 80°C water is also important to the operation, having the potential to expand should market conditions change favorably.

At present, there is no 120°C water available for industrial utilization when electricity production is running at full capacity. However nothing prevents the delivery of 120°C water to industry outside high load periods of electricity production. When the demand for 120°C for industrial use becomes sufficient, additional wells will be drilled at Hveravellir. All piping and equipment needed for the transportation of this water to industrial consumers is already in place.

Heat energy for district heating, electricity production and industry is defined as priority energy. When the load ratio of these three factors is at its optimum, all hot water withdrawn can be utilized down to a temperature of 35°C, and at periods of lower loads down to 20°C. Large amounts of 20-35°C hot water resulting from the production remain

Table 2. Utilization of Thermal Power Above 4°C

Total power from geothermal field			62.2 MW	100%
Power from wells H1, H10 and H16	48.5 MW	78%		
Power from hot springs	13.7 MW	22%		
Sold power			25.2135 MW	41%
Space heating (75°- 35°C)	10.8 MW	17%		
Tap water (bathing, washing) (75°- 4°C)	2.1 MW	3%		
Electricity (121°- 80°C)	1.7 MW	3%		
Industry, 120°C (121°- 80°C)	0 MW	0%		
Industry, 80°C (75°- 35°C)	1.6 MW	3%		
Greenhouses (100°- 35°C)	2.4 MW	4%		
Snow melting (35°- 15°C)	1.0 MW	2%		
Fish-farming (27° and 60°- 4°C)	5.6 MW	9%		
Surplus power utilized			18.1 MW	29%
Bathing lagoon (27°- 4°C)	18.1 MW	29%		
Losses			8.9 MW	14%
In pipeline from Hveravellir (124°- 121°C)	1.1 MW	2%		
In Aðaldalur (100°- 75°C)	0.8 MW	1%		
In Reykjahverfi (100°- 75°C)	1.3 MW	2%		
In the old asbestos pipeline (100°- 60°C)	2.6 MW	4%		
In Húsavík distribution system(80°- 75°C)	1.5 MW	2%		
In effluent pipeline	1.1 MW	2%		
In Power Plant	0.5 MW	1%		
Discarded power			10.0 MW	16%
35°C hot water from space heating and industry	9.5 MW	15%		
15°C hot water from snow melting	0.5 MW	1%		

unused so potential users of water at these temperatures can purchase the 20-35°C water at very economical prices. Snow melting and fish farming are two examples of ideal processes that utilize water at these temperatures. Presently, this unsold water is led to a bathing lagoon constructed south of the Energy Center. Although this utilization of the water does not provide Húsavík Energy with any additional revenue, the bathing lagoon has acted towards improving the community at Húsavík in addition to having a positive future influence on tourism in the region.

Table 2. and Figure 4 provide an overview of the utilization of thermal power from the geothermal field from Hveravellir. The overview assumes utilization of thermal power above the temperature of the cold water supply at Húsavík or 4°C. The summary reflects utilization at maximum load on district heating and electricity production in the year 2001 (see Figure 2).

The annual utilization of thermal power differs considerably from power utilization at maximum load. The utilization period of maximum power for the electricity production is estimated at around 7,000 hours/year. The utilization period of maximum power for district heating is estimated as 4,400 hours/year and to industry around 6,000 hours/year. One of the results of this discrepancy between the various utilization periods is that outside periods of maximum load for district heating, more 80°C water than required by demand is produced at the Energy Center.

While market conditions for this surplus of 80°C water remain unchanged, the water will continue flowing to the bathing lagoon. Losses in main pipelines and in the distribution systems are quite uniform throughout the year, resulting in a higher percentile of the annual energy production than power at maximum load. Water from hot

springs flows freely into collection pipes and during periods of low load, when demand does not require its utilization, this water flows unused into nearby streams and from there into the ocean. Table 3 summarizes the estimated annual utilization of thermal energy (above 4°C) withdrawn from the geothermal field.

CONCLUSIONS

This report describes the utilization of geothermal energy at Húsavík Energy following changes to the district heating system performed in 1999-2000.

Since the construction of the new system was completed in the year 2001, the system as a whole has been operated without any problems, except for the Kalina power plant.

From the initial start up many problems were encountered regarding the Kalina power plant. Immediately at startup separator 1 caused problems, its performance being very poor and a far cry from its capacity. Big droplets of water seeped in with the ammonia gas entering the turbine, wearing it down unnecessarily and as well considerably limiting the plant's output. The separator was replaced after all attempts to rectify these problems proved fruitless.

Reducing the pressure in the condenser to its design value has also proven problematic despite there being more cooling water available than originally predicted. The condenser installed is not of a traditional type. It is a plate-heat exchanger for double phase flow, where the ammonia gas enters in the usual fashion, but the liquid is sprayed in through special nozzles. The placement of these nozzles has been varied with positive results, but despite this the performance of the condenser is less than 100%. Additional heating surface (plates) will improve the situation.

Table 3. Annual Utilization of Thermal Energy Above 4°C.

Total energy from the geothermal field			459 GWh	100%
Energy from wells H1, H10 and H16	339 GWh	74%		
Energy from hot springs	120 GWh	26%		
Sold energy			135 GWh	29%
Space heating	48 GWh	10%		
Tap water (baths, washes)	9 GWh	2%		
Electricity	12 GWh	3%		
Industry, 120°C	0 GWh	0%		
Industry, 80°C	10 GWh	2%		
Greenhouses	10 GWh	2%		
Snow melting	1 GWh	0%		
Fish farming	45 GWh	10%		
Surplus energy utilized			177 GWh	39%
Bathing lagoon	177 GWh	39%		
Losses			75 GWh	17%
In main pipelines and distribution systems.	75 GWh	17%		
Discarded energy			68 GWh	15%
Water discarded from district heating	43 GWh	9%		
Unused water from hot springs	25 GWh	6%		

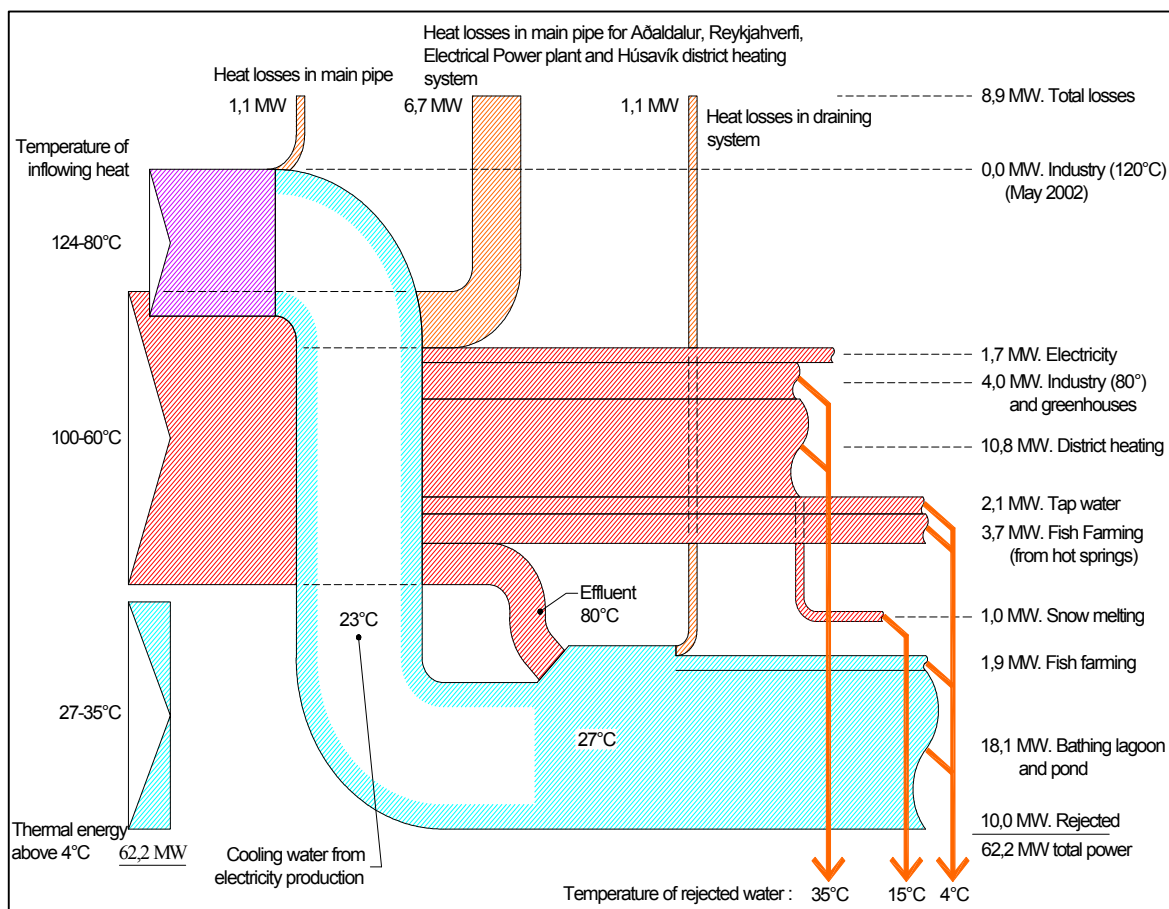


Figure 4. A flow chart depicting the utilization of thermal energy above 4°C at maximum load.

The acceptance certificate was issued after the November 2001 testing. The output was less than calculations indicated, however the certificate was issued as a result of an agreement with the contractor.

The power plant was operated at that demand for approximately six months without any problem. At routine inspection in May 2002, damage due to wear was again noticed. First it was believed that separator 1 was still not functioning properly. Further inspection proved the damage was caused by corrosion of the turbine interior. The blades are made of 13% Cr steel. The turbine interior has been replaced with titanium.

As part of the ongoing betterment of the plant, an offer of an expander giving some 2,150 kW net under the given conditions show that the power plant cycle can still be improved considerably.

After the turbine repair it is reason to believe that the Power Plant will be an outstanding example of an efficient operation and efficient multi-use of geothermal energy.

The main difference between the old system and the new one lies in the utilization of the power contained in steam that prior to the changes was released into the atmosphere. This power is now used to produce electricity. In addition, Húsavík Energy can now offer 120°C hot water for sale to industry and the possibility of selling water at temperatures between 80°C and 40°C has improved greatly.

Flexible utilization of the heat was emphasized, enabling the system to utilize the energy as efficiently as possible under varying conditions at each time. This flexibility provides Húsavík Energy with the opportunity of purchasing electricity from elsewhere and selling the 121°C hot water otherwise used for electricity production to industry, should such utilization provide the company with more revenue. Hot surplus water now flows to a bathing lagoon, which can be enjoyed by inhabitants and visitors to Húsavík, free of charge. Despite the lagoon not providing Húsavík Energy with any direct revenue, it contributes to a more pleasant environment for everyone.

It is the opinion of the report's authors that the objectives set forth for the multiple energy system project in Húsavík have been obtained.

ACKNOWLEDGMENT

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REFERENCE

Orkustofnuns/Gax 20/01/98 - The Hveravellir Geothermal Field, NE-Iceland, Conceptual Model and Reservoir Assessment.

SUDURNES REGIONAL HEATING CORPORATION SVARTSENGI, ICELAND

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Figure 1. Svartsengi Power Plant aerial view.

INTRODUCTION

The Svartsengi geothermal plant is a combined heat and power (CHP) plant. The heating plant supplies hot water to a district heating system (hitaveita) serving 20,000 people. The total installed capacity of the combined plants at Svartsengi is 46.4 MWe electrical power and 150 MJ/s (MWth) in the form of hot water.

The Svartsengi geothermal area is close to the town of Grindavik on the Rekjanes peninsula and is part of an active fissure swarm, lined with crater-rows and open fissures and faults (Figure 1). The high-temperature area has an area of 2 sq km and shows only limited signs of geothermal activity at the surface. The reservoir, however, contains lots of energy and 12 wells supply the Svartsengi Power Plant with steam. The steam is not useable for domestic heating purposes; so that, heat exchangers are used to heat cold groundwater with the steam. Some steam is also used for producing 46.4 MWe of electrical power. Figure 2 shows the distribution system piping hot water to nine towns and the Keflavik International Airport. The effluent brine from the Svartsengi Plant is disposed of into a surface pond, called the *Blue Lagoon*, popular to tourists and people suffering from psoriasis and other forms of eczema seeking therapeutic effects from the silica rich brine. This combined power plant and regional district heating system (co-generation) is an interesting and unique design for the application of geothermal energy.

THE GEOTHERMAL RESOURCE

The geothermal system at Svartsengi is on the Reykijanes Peninsula, right on the boundary of the European and American tectonic plates. The power plant was built on a lava field which dates from a volcanic eruption in the year 1226. The first well was drilled in 1972. The number of drilled wells is currently 20. Of these, 12 are production wells and one well is used for reinjection.

Below 600 meters, the reservoir temperature is almost uniform at 240°C, and the geothermal fluid is brine with salinity approximately 2/3 of seawater, 22,000 ppm total dissolved solids. Since then, the geothermal system has changed from being completely water-dominated, to water-dominated with a steam cap. From the steam cap, saturated steam is produced at 17 to 24 bar wellhead pressure by four shallow wells (400 to 600 m). Other wells produce a mixture of steam and brine, and the range in drilled depth varies from 1000 m to over 2000 m.

THE SVARTSENGI PLANT EVOLUTION

The first heat exchange experiments started in 1974 in a small-scale pilot plant. Deciding from results of this research, a second pilot plant was built in 1976 with enough capacity to supply the town of Grindavik with 20 L/s of hot water. The first plant in Svartsengi, called Power Plant 1, was built in 1976-78. At the time, it was the first of its kind in the

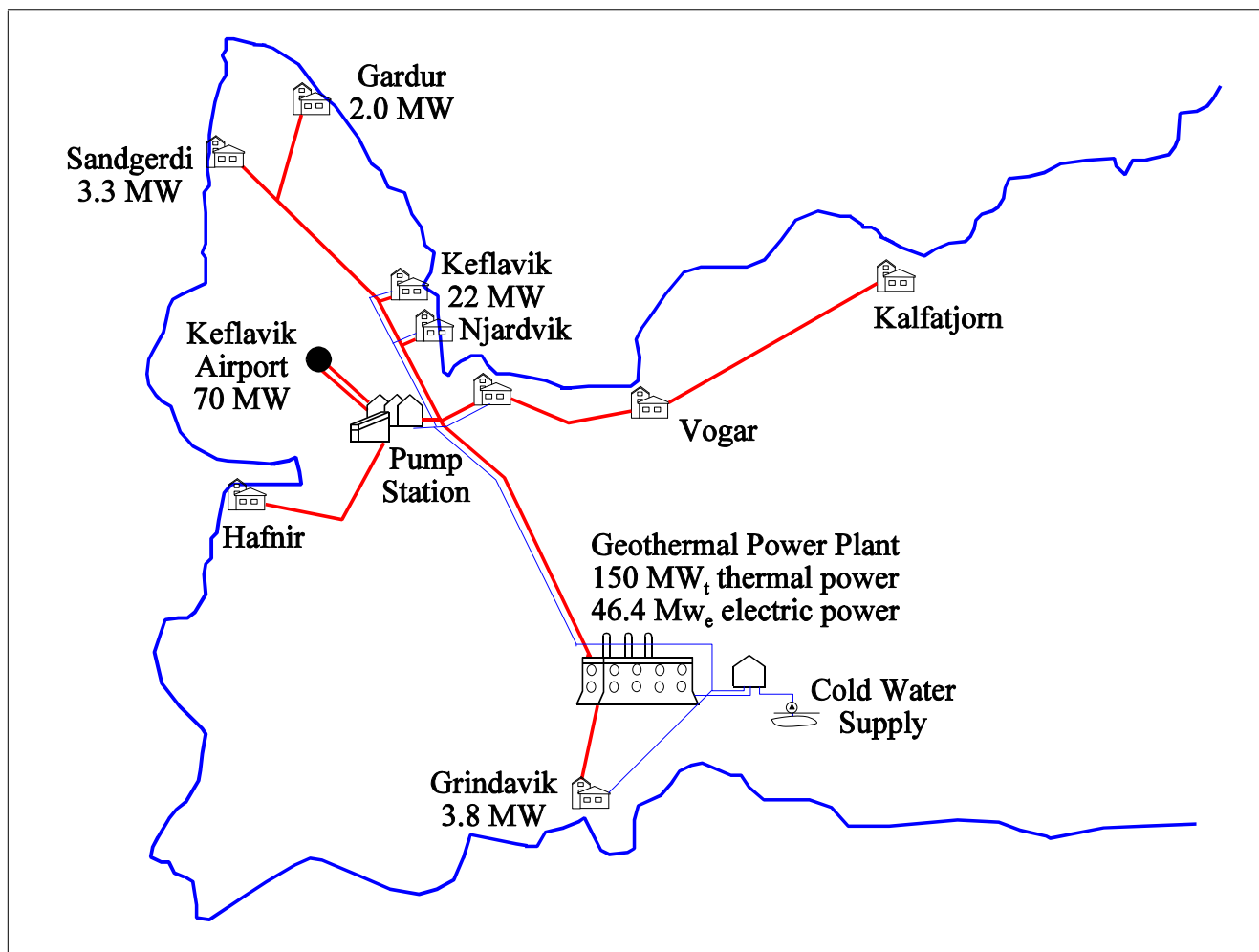


Figure 2. The Sudurnes Regional Heating System layout.

World, it was the first geothermal power plant using a high-temperature geothermal system for simultaneous production of hot water for district heating and electrical power. The engineering and construction of Power Plant 1 was done at the same time as it was a “fast track project.” Getting the main plant started as soon as possible was extremely important because oil prices had risen to new world-record highs and almost all houses in the region were heated with oil. Inexpensive geothermal hot water was badly needed and, therefore, design and construction proceeded simultaneously.

This situation created various problems. For example, the plant’s main building was originally designed to house two heat-exchange flow streams of 37.5 L/s each. Then, it was decided to double the production capacity and install a total of four flow streams in a building originally designed for two. One of the consequences was that bulky and heavy heat exchangers had to be installed in the basement, originally designed to only house pumps.

Right now, the Svartsengi geothermal power plant consists of the following:

Power Plant 1 commissioned in 1977/78: The installed heat exchange capacity was 150 L/s for the district heating system, corresponding to 50 MJ/s (MWth) thermal power. Additionally, two 1-MWe AEG back-pressure steam turbine generators were installed. In the year 2000, half of the heat-exchange system was decommissioned.

Power Plant 2 commissioned in 1981: The installed heat exchange capacity is 225 L/s for the district heating corresponding to 75 MJ/s (MWth) thermal power.

In **Power Plant 3**, a 6-MWe Fuji Electric back-pressure turbine started commercial production on January 1, 1981.

The first part of **Power Plant 4** was commissioned in September 1989, with three 1.2-MWe ORMAT ORC units. On these units, water-cooled condensers are utilized. The second part was commissioned in 1993 by adding four 1.2-MWe ORMAT units with air-cooled condensers.

In 1995, the project for **Power Plant 5** started out as a renewal of **Power Plant 1**. The main reasons were:

- The thermal efficiency was not up to today's standards, mainly because the small back-pressure steam turbines were very inefficient.
- Maintenance facilities in Power Plant 1 were absolutely unacceptable due to tightly spaced equipment, there were no overhead crane, high-ambient temperature, and a lot of noise.
- The production capacity of Power Plant 1 was not enough to sustain the hot water consumption of the district heating system during even the warmest summer days. Thus, it was impossible to shut down Power Plant 2 for more than three consecutive days for maintenance. This made all major overhauls of Power Plant 2 difficult, and influenced the overall operational reliability.

In **Power Plant 5**, a 30-MWe Fuji Electric extraction-condensing steam turbine was commissioned in November 1999, and in April 2000, a district heating part of 75-MJ/s (MWth) thermal power was commissioned.

The plant maintenance and operating staff, consist of 22 men, regularly attend to 12 turbines, specifically, five steam turbines and seven Organic Rankine Cycle (ORC) units. In addition, they look after 36 cooling fans, 17 geothermal wells and wellheads, 70 control valves, 100 pumps, 20 kilometer pipelines and thousands of valves that require maintenance.

THE FLOW STREAM

It is practical to start with the “raw materials” of the plant, illustrated in Figure 3. The numbers in parentheses refer to details shown in Figure 3. We have geothermal steam and brine (1) and cold freshwater (2). Brine (1) at 240°C flows into the wells through the holes in a slotted liner. On its way up, the brine starts to boil because of the pressure drop. In the wellhead (3), there is a mixture of steam and brine at about 16 bar. The pressure is reduced to 6 bar before the mixture enters the connecting pipelines to the separators (4). From the separators, steam goes to the back-pressure turbine (5). Back-pressure steam (6) is consumed either by the heat exchangers (7) or the ORCs (8). The back-pressure is controlled by control valves (9) venting the steam to the atmosphere through exhaust stacks (10).

The brine (11) from the separator (4) is flashed into a low-pressure separator (12) operating at 0.8 bar. The brine then flows through a barometric pipe (13) into the “Blue Lagoon.” From this brine, silica precipitates rapidly and makes the normally permeable lava practically watertight, and thus, the “Blue Lagoon” is formed in a trough in the lave field, about 20 meters above groundwater level.

The cold 5°C freshwater (2) is pumped from shallow wells and rifts about 5 km north of the power plant. The first stage in the heating process is the condenser of the water cooled ORCs (14). Here the water is heated to 25°C. The next stage in the production of district heating water is a direct contact heat exchanger (15); where, the water is heated against the stream of low-pressure steam. At the same time, de-aeration (degassing) of the water takes place. The deaeration is essential to prevent the water corroding the steel district-

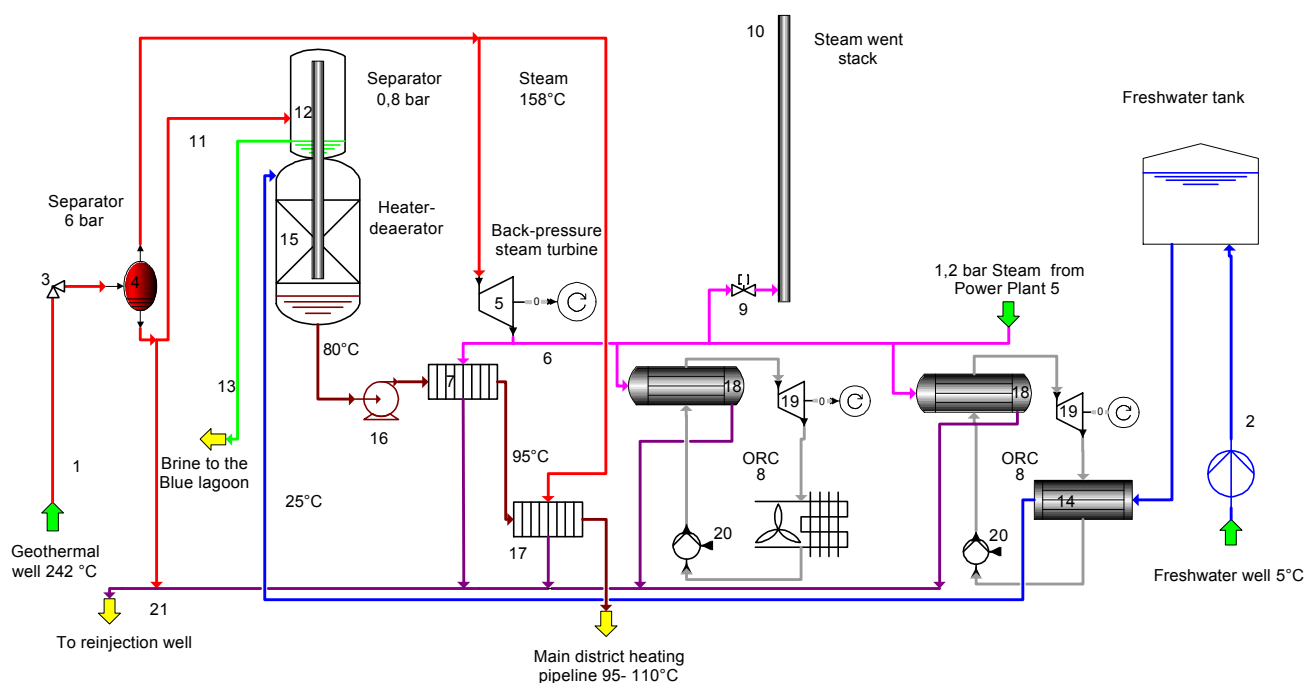


Figure 3. Svartsengi Power Plant flow diagram.

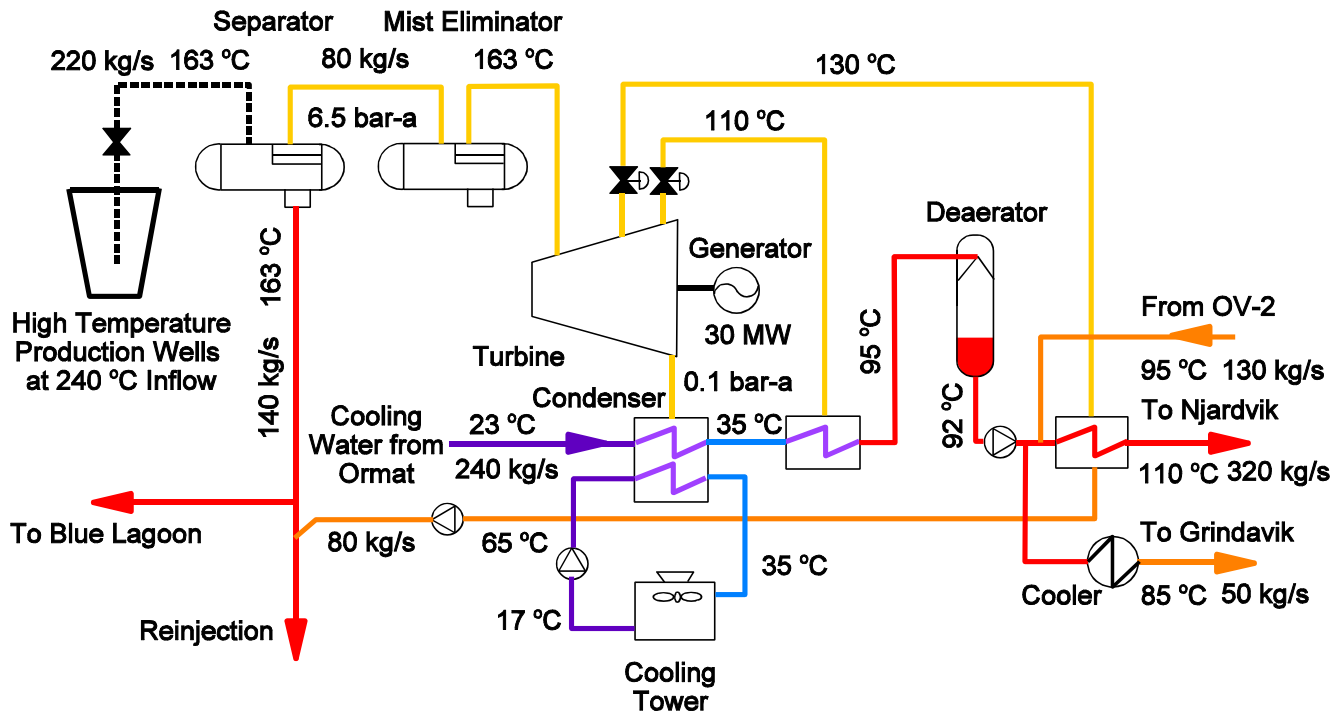


Figure 4. Power Plant 5 flow diagram.

heating pipework. In the deaeration process, dissolved oxygen is eliminated. The deaerated water is pumped (16) through a series of plate heat exchangers; the first one heats the water to about 95°C using back-pressure steam and the second (17) to over 100°C or up to 117°C depending on demand of the district heating system.

The ORC (8) is a vapor power cycle. The working fluid in the cycle is isopentane, a hydrocarbon with a boiling point of 27°C at atmospheric pressure. The back-pressure steam is used to heat the isopentane in a vaporizer (18) at approximately 6 bar pressure. The isopentane gas is then expanded in a turbine (19) which turns a generator. A condenser (14) receives the gas from the turbine, the heat is removed with cooling water and the gas is condensed into a liquid at atmospheric pressure. Finally, the cycle is closed by pumping (20) the isopentane liquid again, under pressure, into the vaporizer.

Finally, the condensate is mixed with brine and injected back to the geothermal reservoir (21). The flow stream of Power Plant 5 is shown in Figure 4.

POWER PLANT OV-5

The new power plant at Svartsengi (OV-5) is designed for 3 MWe electricity generation and 70 MWt heating output (Figure 4). The district heating part is designed to heat from about 23°C to 90-95°C, and deaerate 240 kg/s of pre-heated freshwater coming from the ORMAT turbines. The pumps, final-heaters and coolers pump 70 kg/s of 85°C water to the town of Grindavik and/or 240 kg/s of 110-115°C water to the town of Njardvik. The maximum pumped in OV-5 to these towns is 240 kg/s. Turbine extractions supply

enough low-pressure steam for after-heating and final-heating of the district heating water.

It is also possible to receive up to 150 kg/s of district heating water at about 95°C from Power Plant 2 (OV-2), and heat it to 110-115°C, together with the water produced by OV-5. This solution is adopted because the steam in OV-5 is extraction steam (2.5 bara); whereas, the steam in OV2 is high-pressure steam (6.5 bara) that has been used as possible for electrical production. OV-2 pumps this water through the final heaters in OV-5. In this way, OV-5 can simultaneously supply 320 kg/s of 110-115°C hot water to the Njardvik pipeline and 70 kg/s of 85°C hot water to the Grindavik pipeline. Figure 4 shows a flow diagram of the OV-5 power plant.

The turbine is designed to operate at full-load and also supply extraction steam for the district heating system. If the power is reduced, eventually the extraction steam pressure becomes too low to be used for the district heating heat exchangers, and instead of the extraction steam, the high-pressure steam, taken through the bypass valves, must be used to heat the district heating water.

The high steam pressure to the turbine will be controlled by the existing control valves in OV-2. In addition, the turbine will be equipped with a valve that reduces the turbine power if the steam pressure drops below 6.5 bara.

The medium pressure (first extraction) varies with the district heating load, 2.7 to 3 bara. If the turbine load is reduced, this pressure drops. In order to maintain minimum pressure, a bypass valve controls steam from the high-pressure steam supply in order to prevent the medium pressure from dropping below 2.5 bara.

The low pressure (second extraction) varies with the district heating load (1.4 bara at maximum and 1.9 bara at the minimum district heating load). A control valve between power plants OV-5 and OV-2 controls the extraction pressure based on a variable set-point that depends on the district heating load as measured by a flow meter. It is assumed that the turbine is run at maximum load (30 MWe). If the turbine load is reduced, the extraction pressure drops below 1.3 bara at some point. Then, a bypass control valve opens to maintain the pressure at 1.3 bara. At the same time, the check valve reduces the steam coming from the extraction. Chimney valves in OV-2 control the pressure at 1.3 bara at that side, so that the 6-MWe turbine and the ORMAT turbine will not be disturbed because of variability in low-pressure steam in OV-5.

The condenser pressure is controlled by the temperature of the cooling water from the cooling tower. The mixture of condensate water with brine is controlled by two valves that are operated by the same regulator (one opens—whereas, the other closes).

CONCLUSIONS

The total performance of the new geothermal co-generation power plant at Svartsengi is improved by using turbine extractions, instead of high pressure steam, to heat freshwater to 110°C in heat exchangers. Energy balance calculations show that the utilization efficiency of the power plant OV-5 is improved by 15% with this type of operation and by 14-22% at different heat loads. The turbine model shows that at 21-24 MWe, electrical output and different heat loads, the pressure of the first and second extractions drops below 2.5 bara and 1.3 bara, respectively. At this point, it is necessary to supply high pressure steam to the heat exchangers.

Geothermal power plants, particularly those operating on the flash-steam principle, offer the opportunity to combine electricity generation with direct heat applications. The latter utilization can be accomplished using the thermal energy available in a waste brine and rejected heat in a condenser to heat freshwater, which can then be distributed to a variety of end users. The technical feasibility and design of such co-generation power plants depend on a number of factors, including the reservoir temperature of the geothermal fluid, the type of flash system used in the power plant (single- or double-flash), the distance to end users and the types of applications. The climate, topography and cost of other energy alternatives will also influence the final decision on whether to use geothermal co-generation power plants.

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HITAVEITA REYKJAVIKUR AND THE NESJAVELLIR GEOTHERMAL CO-GENERATION POWER PLANT

Edited by John W. Lund
Geo-Heat Center

BACKGROUND

When Ingólfur Arnarson sighted land on the voyage which would make him the first settler in Iceland, he threw the pillars of his high seat overboard and relied on the gods to direct him to where he should settle. His slaves found them washed ashore in a bay where “smoke” rose out of the ground. Therefore, they called it Reykjavik, “Smoky Bay.” But the smoke after which Iceland’s capital is named was not the result of fire, but was rather steam rising from hot springs.

Ancient records only mention the use of geothermal springs for washing and bathing. The best known examples are the Thvottalaugar (washing pools) in what is now Laugardalur in Reykjavik, and the hot pool where saga writer Snorri Sturluson bathed at his farm in Reykholt in western Iceland.

The first trial wells for hot water were sunk by two pioneers of the natural sciences in Iceland, Eggert Ólafsson and Bjarni Pálsson, at Thvottalaugar in Reykjavik and in Krísuvík on the southwest peninsula, in 1755-56. Further wells were sunk at Thvottalaugar in 1928 through 1930 in search of hot water for space heating. They yielded 14 liters per second at a temperature of 87°C, which in November 1930 was piped three kilometers to Austurbejarskóli, a school in Reykjavik which was the first building to be heated by geothermal water. Soon thereafter, more public buildings in that area of the city as well as about 60 private houses were connected to the geothermal pipeline from Thvottalaugar.

The results of this district heating project were so encouraging that other geothermal fields began to be explored in the vicinity of Reykjavik in Mosfellssveit, by Laugavegur (a main street in Reykjavik) and by Ellidaár (the salmon river) flowing at that time outside the city but now well within its eastern limits. Results of this exploration were good. A total of 52 wells in these areas are now producing 2,400 liters per second of water at a temperature of 62-132°C.

Reykjavik Energy (Orkuveita Reykjavíkur) was established in 1999 by the merger of Reykjavik District Heating and Reykjavik Electricity. The company is responsible for distribution and sale of both hot water and electricity as well as the water works in the city. The total number of employees is 492 and the turnover in 2003 was 183 million US\$.

District heating in Reykjavik began in 1930 when some official buildings and about 70 private houses received hot water from geothermal wells close to the old thermal springs in Reykjavik. Reykjavik District Heating (now Reykjavik Energy) was formally established in 1943 when production of hot water from the Reykir field, 17 km from the

city, started. Reykjavik Energy is by far the largest of the 26 municipality-owned geothermal district heating systems in Iceland. It utilizes low-temperature areas within and in the vicinity of Reykjavik as well as the high-temperature field at Nesjavellir, about 27 km away. Today, it serves about 180,000 people or practically the whole population in Reykjavik and six neighboring communities (Table 1).

Table 1. Reykjavik Energy - District Heating 2003

Number of people served	179,085
Volume of houses served	42,607,000 m ³
Water temperature at user end	75°C
Number of wells in use	62
Installed capacity	830 MWt
Peak load 2003	593 MWt
Total pipe length	2,157 km
Water delivered	59,600,000 m ³ /year

Figure 1 is a simplified flow diagram of the Reykjavik district heating system showing the Nesjavellir plant.

THE DISTRIBUTION SYSTEM

The geothermal water from Reykir in Mosefellsbær flows through a main pipeline to six reservoir tanks just outside Reykjavik that hold 54 million liters. From there, the water flows to six storage tanks on Öskjuhlíó in mid Reykjavik holding 24 million liters. Nine pumping stations, distributed throughout the servicing area, pump the water to the consumers. The water from Nesjavellir flows to two tanks on the way to Reykjavik that hold 18 million liters. From there, the heated water flows along a main pipeline to the southern part of the servicing area. The heated freshwater and the geothermal water are never mixed in the distribution system but kept separated all the way to the consumer.

The length of the pipelines in the distribution system is about 1300 km. This includes all pipelines from the wells to the consumer. The main pipelines are 90 cm in diameter. The pipe from the main line to the consumer is usually 2.5 cm in diameter. Some of the pipes laid in 1940 are still in use. They were originally insulated with turf and red gravel. The newer pipes are insulated with foam or rock wool.

Reykjavik Energy uses either single or a double distribution system (Figure 2). In the double system, the used geothermal water from radiators runs back from the consumer to the pumping stations. There, it is mixed with hotter

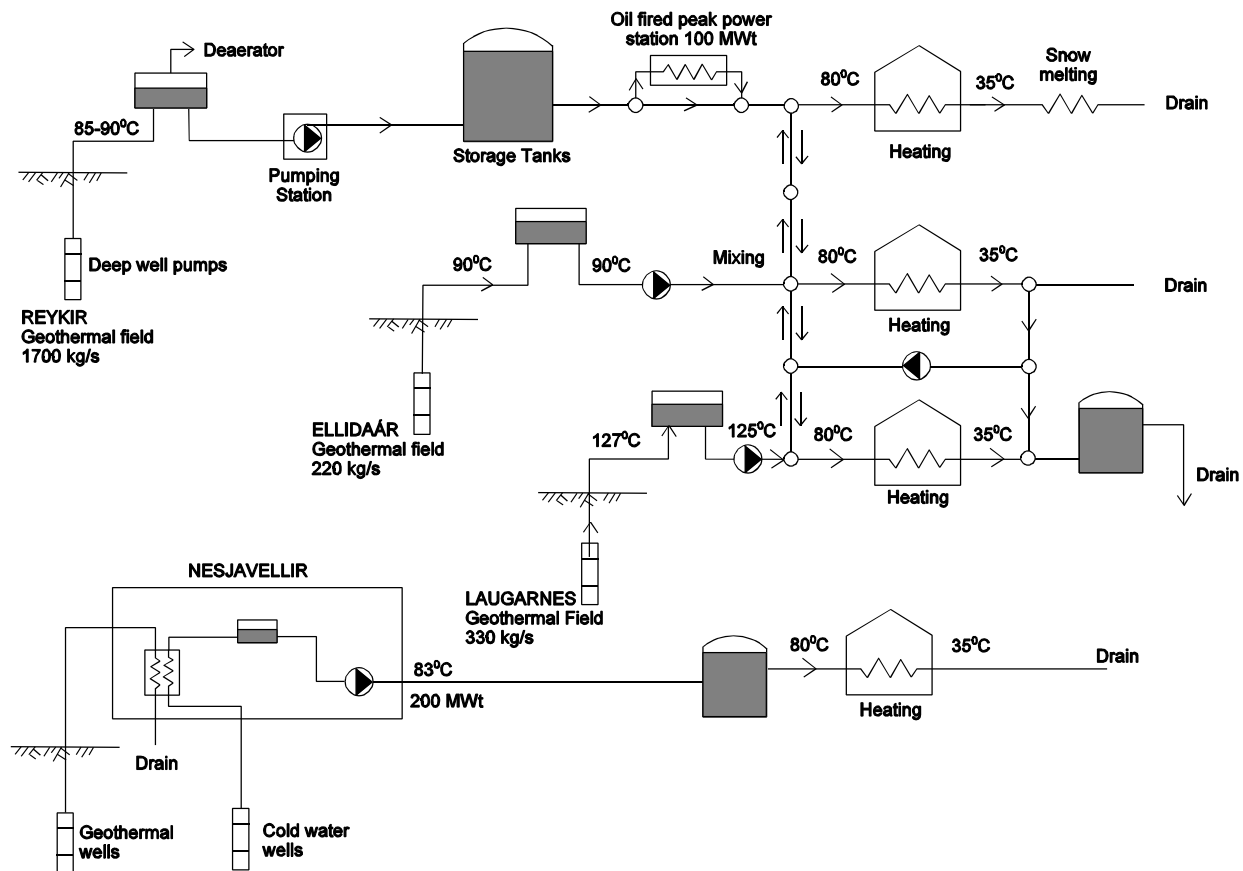


Figure 1. Simplified flow diagram for the district heating in Reykjavik.

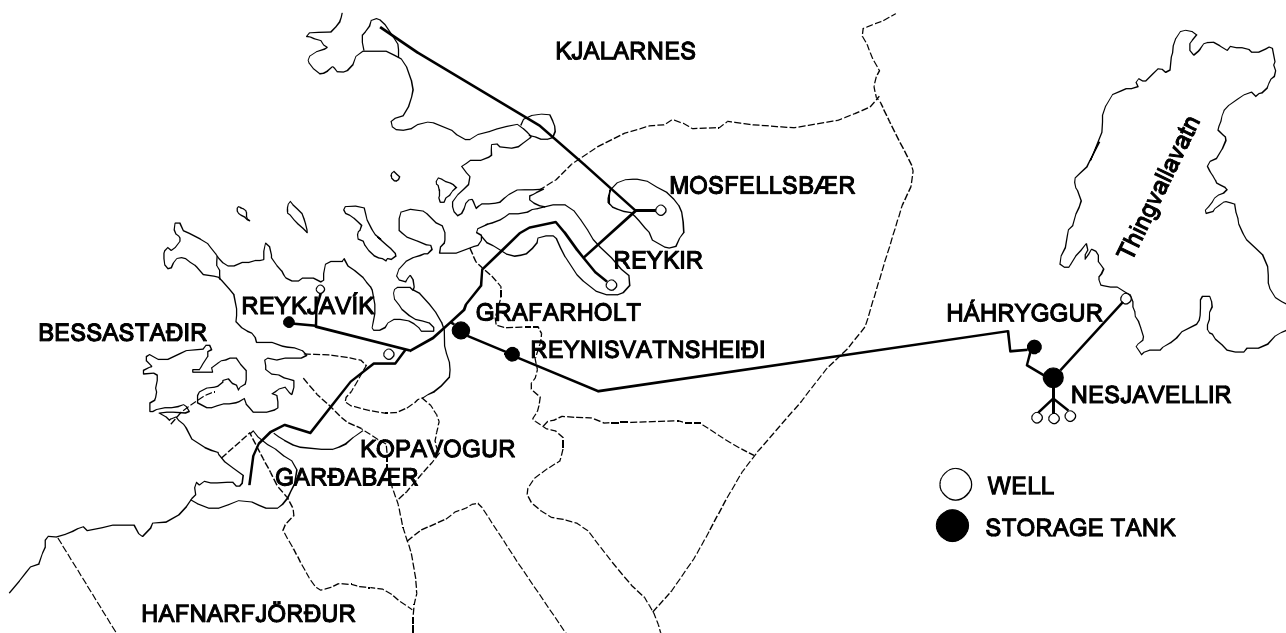


Figure 2. The hot water pipeline from Nesjavellir to Reykjavik.

geothermal water and serves to cool that water to the proper 80°C, before being re-circulated. In the single system, the backflow drains directly into the sewer system. The utility serves about 170,000 people, and in 2002, they used about 63 million cubic meters of water, of which 7 million are recycled backflow waters. In the coldest periods, about 3800 liters per second are required for space heating. About 85% of the hot water from Reykjavik Energy is used for space heating, 15% being used for bathing and washing. After the hot water has been used for space heating, it is 25-40°C. In recent years, it has become increasingly common to use this water to melt snow off pavements and driveways. Although geothermal energy is sustainable, it is necessary to make sensible use of it. It is most important to insulate buildings and to install thermostatic controls to conserve the heat. Consumers pay for the geothermal water by volume in Reykjavik. It is, therefore, to their advantage to use the water wisely. The price of thermal water in Reykjavik is approximately one-third of the price of heating with oil.

NESJAVELLIR PLANT

The Nesjavellir Geothermal Field is a high-enthalpy geothermal system within the Hengill Central Volcano in southwestern Iceland. The Nesjavellir Geothermal Power Plant was commissioned in 1990, following an intensive drilling and testing phase in the 1980s. By that time, 14 production boreholes had been drilled, and all except one were successful. Initially, the plant produced about 560 L/s of 82°C hot water for district heating (100 MWt), using geothermal steam and water to heat cold groundwater. In 1991, the capacity was expanded to 150 MWt, and 1998 to 200 MWt. At that time, the production of electricity commenced with the installation of two 30-MWe turbines. In 2001, the third turbine was installed, increasing the capacity to 90 MWe. In 2003, the hot water production was increased to 290 MWt, and the fourth electricity turbine will be online production in 2005, bringing the capacity to 290 MWe. The stepwise increases in production are summarized in Table 2. Initially, only four geothermal wells were connected to the plant, but gradually more wells have been connected as the capacity of the power plant has been increased. Presently, 14 boreholes are connected to the Nesjavellir plant, including five new wells drilled in 1999-2003.

Table 2. Co-Generation of Electricity and Hot Water at Nesjavellir

	Hot Water		Electricity
	L/s	MWt	MWe
1990	560	100	
1991	840	150	
1998	1120	200	60
2001			90
2003	1640	290	
2005			120

The modular development of the Nesjavellir Power Plant is a good example of the development of a geothermal resource. Initially, the reservoir was tested with relatively small discharge/production, but with an intensive monitoring program and revisions of a numerical model of the resource has allowed increased production in line with the known potential of the field.

Plant Operation

A mixture of steam and geothermal brine is transported from the wells to a central-separation station at 200°C and 14 bar. After being separated from the brine, the steam is piped through moisture separators to steam heat exchangers inside the plant building. The steam can be piped to steam turbines for co-generation of electricity. Unutilized steam is released through a steam exhaust.

In the steam heat exchangers consisting of 295 titanium plates, the 120°C steam is cooled under pressure into condensate whose heat is then transferred to cold freshwater in condensate heat exchangers. The condensate cools down in the process to 20°C.

Separated geothermal brine has its heat transferred to cold freshwater by geothermal brine heat exchangers

Cold water at 4°C is pumped from wells at Grámelur, near the shore of Lake Thingvallavatn, to a storage tank by the power house. From there, it is pumped to the steam heat exchangers; where, its temperature is raised to 85-90°C.

Since the freshwater is saturated with dissolved oxygen that would cause corrosion after being heated, it is passed through deaerators; where, it is boiled at low volume pressure to remove the dissolved oxygen and other gases, cooling it to 82-85°C as described earlier.

Finally, a small amount of geothermal steam containing acidic gases is injected into the water to rid it of any remaining oxygen and lower its pH, thereby preventing corrosion and scaling.

A flow diagram of the process is shown in Figure 3.

Distribution

The Nesjavellir power station is situated at an elevation of 177 meters above sea level (Figure 4). The water is pumped by three 900-kW (1250-hp) pumps through a main pipeline of 900 millimeters in diameter to a 2000-m³ storage tank in the Hengill area at an elevation of 406 meters.

From there, the water flows by gravity, through a pipeline which is 800 millimeters in diameter, to storage tanks on Reynisvatnheidi and Grafarholt on the eastern outskirts of Reykjavik (Figure 2). Those tanks are at an elevation of 140 meters above sea level, and have control valves to regulate the flow of water through the pipeline and maintain a constant water level in the tank in the Hengill area.

From the storage tank, near Reykjavik, the water is fed through pipelines to the communities which are served by Orkuveita Reykjavíkur.

From Nesjavellir to Grafarholt, the transmission pipe measures about 27 kilometers in length, and has fixed and expansion points every 200 m. It is designed to carry water at

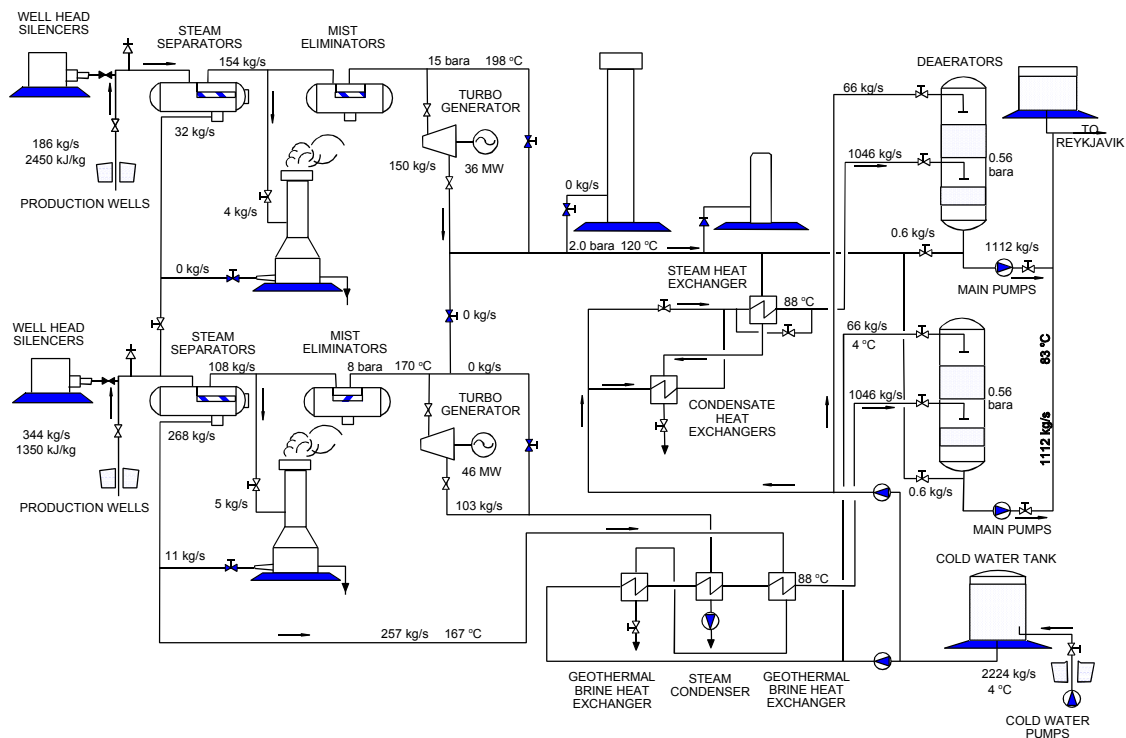


Figure 3. Flow diagram of the Nesjavellir plant.

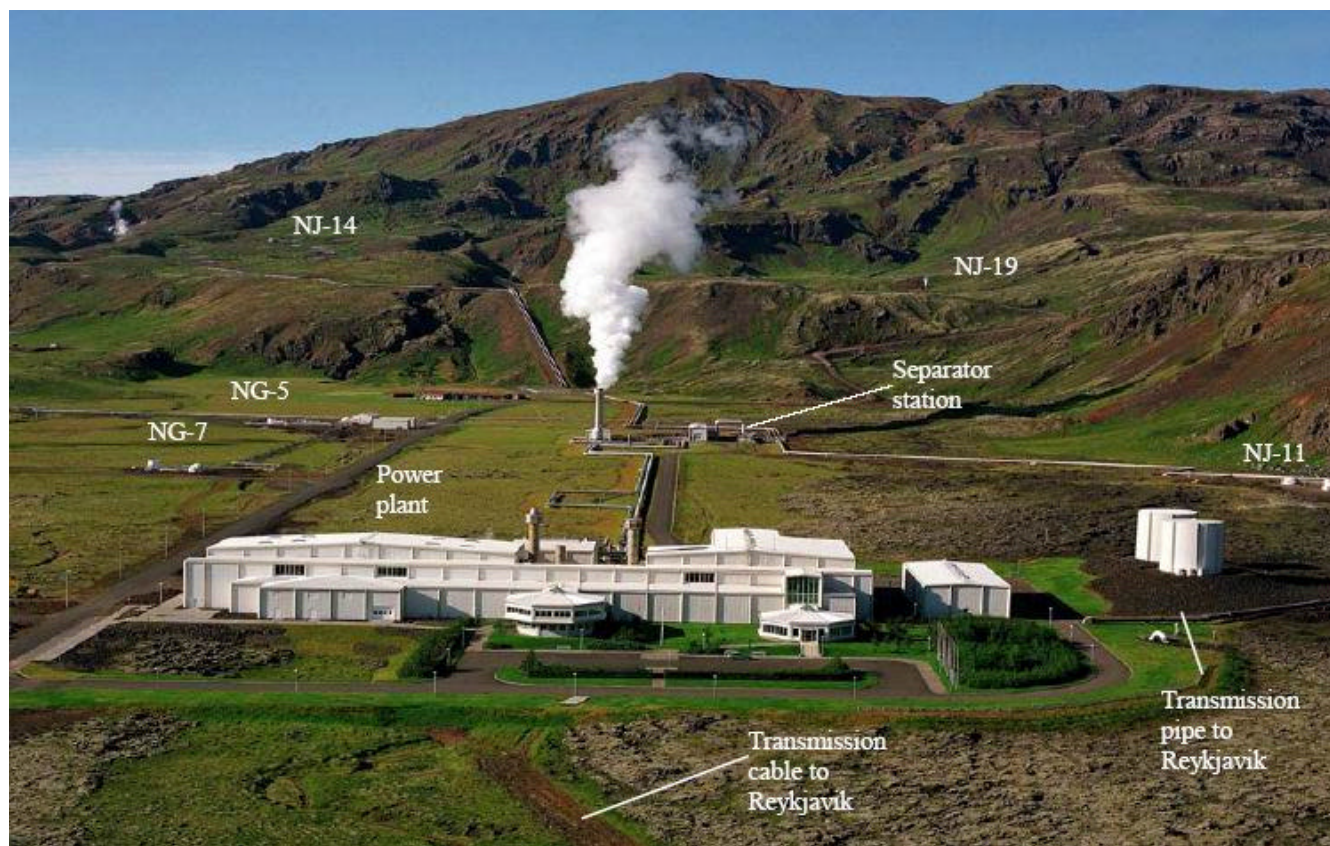


Figure 4. Overview of the Nesjavellir plant site.

up to 96°C, with a transmission rate of 1,870 liters per second. During phase one of the project, its flow rate was around 560 liters per second; whereby, the water took seven hours to run the length of the pipe and cooled by 2°C on the way. Good insulation and a high volume of water are the most crucial factors contributing to this low heat loss. At later construction stages at Nesjavellir, the flow rate will be tripled, reducing the heat loss to less than 1°C.

The 8-to-10-mm thick steel pipe is insulated with 100 mm of rock wool and covered with aluminum sheets; where, it lies above the ground, and insulated with polyethylene and covered with PEH plastic where it lies underground. A corrugated plastic vapor barrier is located under the aluminum skin to keep the rock wool insulation dry. Drip holes are provided at bearing plates to remove any condensation. Its high insulative properties are shown by the fact that snow does not melt on the part that lies above the surface. For environmental and traffic reasons, a 5-kilometer section of the pipe is underground. The surface section also runs under automobile crossings at several points which have been well marked. Provisions are also provided for snowmobile crossings in winter (Figure 5).



Figure 5. *The 800-mm diameter pipeline with a snowmobile crossing.*

ENVIRONMENTAL BENEFIT AND MONITORING

Before 1940, the main energy source for space heating in Reykjavik was the burning of fossil fuels. At that time, black clouds of smoke were common over Reykjavik, but since then, geothermal energy has gradually replaced imported fossil fuel, and today, over 98% of houses in Reykjavik and neighborhoods enjoy geothermal heating. It has been estimated that in 1960, the annual emission of greenhouse gases due to space heating in the Reykjavik area was about 270,000 tonnes. Today, this figure is about 12,000 tonnes, all natural emission from the Nesjavellir high-temperature area. This is one of the main benefits of utilization of geothermal energy for space heating. Other benefits of the use of geothermal energy for district heating is that the energy is indigenous energy, it is relatively cheap and promotes cascading uses such as swimming pools, greenhouses, heated-garden conservatories and snow melting.

A program to monitor the response of the Nesjavellir geothermal system as well as to record the influence of the utilization on the environment has evolved through the lifetime of the Nesjavellir project. A program was set up to monitor the natural runoff from the field in the early 1980s, prior to the drilling and testing of production wells. Ever since drilling commenced in the 1980s, downhole measurements and flow testing has been a part of the monitoring program as well as chemical sampling. Currently, the monitoring program is put forward in a number of written operation procedures, and since 2003, the monitoring program fulfills the requirements of ISO 9001.

The volume of discharge from the Nesjavellir geothermal reservoir is monitored and the figures are updated annually (Figure 6). The calculations are based on daily records on the operation of each well, using the setting of a control valve (if present), wellhead pressure and flow measurements. During the drilling and testing period in the 1980s, flow measurements were frequent, but after production started, these measurements are limited to short test periods, usually during the few maintenance stops of the power plant. The cumulative extraction of fluid is, therefore, evaluated from wellhead pressure using an established flow rate/wellhead pressure output curve for each well. The combined monthly discharge from all the wells is calculated and compared to the measured volume of geothermal steam and water in the separation station. Experience shows that there is a good agreement between these two independent methods; generally, the difference is less than 1%.

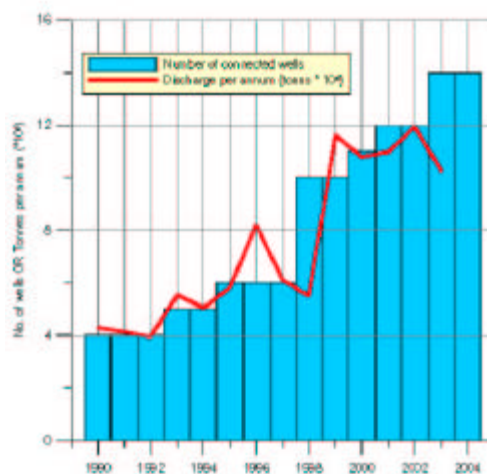


Figure 6. *Annual discharge and the number of connected production wells.*

Geothermal steam and water from 14 production wells are gathered in a central separator station, supplying up to 1100 kg/s of water. Electricity is generated in condensing steam turbine units. The exhaust steam from the turbines is used to preheat freshwater in the condensers. The separated geothermal water is used in heat exchangers to heat the preheated water up to the required temperature. Finally, the water is treated in deaerators to suit the requirements of the distribution system. Thus, the steam and the separated

geothermal water are utilized, in the most economical way possible, for co-generation of electric and thermal power, which is also good for the environment as less heat is released to the atmosphere than in conventional geothermal plants.

Comparison with alternative energy sources show that CO₂ and sulphur released to atmosphere, by using geothermal energy, is relatively small for the power production at Nesjavellir (e.g., the average amount of CO₂ released is within 1% of that of a conventional oil or coal-fired power plant of similar capacity).

ACKNOWLEDGMENTS

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HOT ARTESIAN WATER POWERS AN OUTBACK TOWN IN AUSTRALIA

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INTRODUCTION

The small town of Birdsville (139°53'E 25°21'S) is situated in arid south west Queensland approximately 1000 miles northwest of the state capital Brisbane (Figure 1) and on the edge of the Simpson Desert. Because of its remote location, the town is not connected to the Australian national power grid and requires its own power generation facilities. Established in the 1870s, Birdsville takes its name from the prolific bird life that soon arrives when the nearby Diamantina River intermittently fills with water. The town currently has a population of around 100 people and is sustained economically mainly by adventure tourism.



Figure 1. *The location of Birdsville and the Great Artesian Basin.*

The town's need for electric power follows a familiar seasonal pattern with highest demand in the hot summer months when air-conditioning is used extensively and a relatively low demand in winter. This demand cycle from the town's small population sees less than 120 kW of power required in winter and upwards of 250kW needed in summer. The one exception is during the town's once yearly "races weekend" in spring when the population can swell to more than 5000. The Birdsville Races is a major tourist event that draws tourists from all over Australia, many of whom arrive in light aircraft. As a result, the town has an excellent all-weather airstrip (Figure 2) something quite unusual for a town of its size.

To cope with the annual variations in the demand for electricity an integrated mix of generation systems are used:



Figure 2. *The town of Birdsville with its airstrip in the foreground and the Diamantina River behind the town.*

- A geothermal power station with a nominal power rating of 150kW,
- A liquefied petroleum gas (LPG) generator set with a rating of 300 kW, and
- Two 150 kW diesel generator sets.

The geothermal power system is installed on a free flowing artesian bore that was drilled to a depth of 1230 m to provide the town's water supply approximately 50 years ago. The water flows through a 6-in. casing to surface at a temperature of 98°C and a rate of 27 L/s. The source of this water is an aquifer in the underlying Great Artesian Basin which underlies approximately 1.7 million km² of central and eastern Australia (Habermehl, 1980).

A geothermal power station (Figure 3) was originally installed on the bore in 1989 and commenced operation in 1992 (Burns, et al, 2000). However, the original system suffered from a number of technical problems centered on the use of R114 chlorofluorohydrocarbon as the working fluid. In 1999 the plant was upgraded with a grant of A\$95,300 (US\$73,900) from the Queensland Sustainable Energy Innovation Fund and support from Ergon Energy Corporation Ltd.

The upgrade shown schematically in Figure 4 involved:

- Conversion from the R114 chlorofluorohydrocarbon working fluid previously used to isopentane which is more volatile and produces a larger volume of vapor.
- Installation of a new plate heat exchanger, a new multi-stage liquid pump and larger diameter pipes and fittings to handle the larger volumes of the new working fluid.



Figure 3. *The Birdsville Geothermal Power Station is situated on a free flowing bore a mile or so out of town (Australian Broadcasting Corporation).*

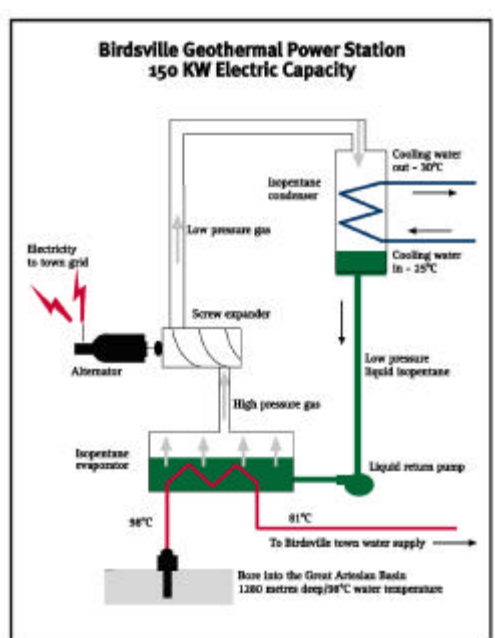


Figure 4. *Schematic diagram of the Birdsville Geothermal Power Station (Queensland Environmental Protection Agency).*

Some of the 81°C outlet water from the power station is piped into Birdsville for the town's limited water supply requirements. The remainder is flowed into a channel (Figure 5); where, it is used to water stock animals once it has travelled far enough to cool down.

The Birdsville geothermal power plant now provides 120kW of net power output after parasitic losses of 30kW.

The latter are principally associated with the operation of the plant's pumps. With a capacity factor of >95%, the geothermal power system is so reliable that it provides all of the town's electricity needs at night and during the cooler winter months when air-conditioning is not required (Queensland EPA, 2002). An automatic control system and radio telemetry links the geothermal system with the town's LPG and diesel powerhouse 1½ miles away. The powerhouse is shut down when the geothermal system is able to satisfy the town's demand for electricity.



Figure 5. *The outlet water from the power station is flowed in a channel until it has cooled sufficiently for use by stock animals (Australian Broadcasting Corporation).*

In the 2002-03 financial year, the geothermal system provided 529,326 kWh to the town of a total power generation of 1,630,985 kWh. This saves 42,000 gallons of diesel fuel annually at a saving of A\$135,000 (US\$104,700) and 430 tonnes of CO₂ emitted.

The geothermal power station is currently shut down for a A\$100,000 (US\$75,600) upgrade to improve building ventilation and to install isopentane gas detectors for improved plant safety. It is expected that the power station will be back on-line in August 2005.

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BAD BLUMAU (STYRIA, AUSTRIA) THE SUCCESS STORY OF COMBINED USE OF GEOTHERMAL ENERGY

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INTRODUCTION

The main geothermal resources of Austria (area 83,858 km², 8.05 million inhabitants in 2002, capital city Vienna) are in the sedimentary basins bordering the Eastern Alps (Styrian Basin, Upper Austrian Molasse Basin, Vienna Basin; Figure 1). In the 1977-2004 period, a total of 63 geothermal wells with a cumulative length of some 100 km have been drilled (Goldbrunner, 2005). A high percentage of these wells were intended for balneological use (thermal spas, curing, leisure resorts, hotels). The development of spas had an enormous economic impact especially in the Styrian Basin in SE Austria, where eight new spas were built between 1977 and 2004. Approximately 3.5 million guests visit the thermal spas per year (Hoenig, 2005). One of these spas, Bad Blumau, is an example for successful combination of the use of geothermal heat for power generation, district heating and direct use of the water for swimming and treatments.



Figure 1. *Geothermal areas in Austria.*

BAD BLUMAU GEOTHERMAL PROJECT Geological Background

Bad Blumau is situated in the Styrian Basin which is a sub-basin of the Pannonian Basin separated in the subsurface and locally also at the surface by a swell zone, called the Burgenland swell. In contrast to the Pannonian Basin, no economically exploitable hydrocarbon resources have been detected in the Styrian Basin so far. The exploration drillings and seismic surveys of the hydrocarbon industry are the basis for the geothermal exploration.

The Styrian Basin is a Miocene extensional basin. Due to heat flow values of up to 95 mW/m², temperatures of more than 100°C are encountered at depth of 2,000 m. In

the structurally higher parts, convective heat flow leads to local anomalies. The basement of the basin is composed of high-grade metamorphic crystalline rocks and anchimetamorphic Paleozoic phyllites and carbonate rocks of the Austroalpine nappe. The carbonate rocks (limestones and dolomites of mainly Devonian age) form an important deep aquifer which is suitable for the use of geothermal energy. The mainly clastic tertiary basin fill consists of sediments of Carpathian to Upper Miocene age with a maximum thickness of 2,900 m. Aquifers bearing thermal waters are in the Badenian and Sarmatian sequence and consist mainly of sand and sandstones with different clay and silt contents. As the transmissivities of the Miocene aquifers are one to two orders of magnitude lower than those in the Paleozoic carbonate rocks, they are exploited only for balneological use.

The success story of Austrian Spas in the second half of the 20th century has started in the Styrian Basin. In the period 1977-2004, 26 geothermal wells with a cumulated depth of 40.7 km were drilled here. More than 80% have been intended for balneology. Since 1977, eight new spas have been established in the region which until then had been dominated by agriculture.

Project History of Bad Blumau

The geothermal project of Bad Blumau had its origin in the hydrocarbon exploratory drilling Blumau 1. It explored a regionally developed normal fault with a throw of more than 1,000 m, thus separating the Paleozoic sequence (Figure 2). Blumau 1, situated in the uplifted part of the throw came into Paleozoic phyllites at a depth of 1,708 m without encountering carbonate rocks. After side track operation, the deviated drilling Blumau 1a ran parallel to the fault and reached fractured Paleozoic carbonate rocks at a measured depth of 2,664 m (2,583 m TVD). Due to fracturing, heavy mud losses occurred which forced drilling to be stopped at a depth of 3,046 m. According to mining regulations the bore had to be closed by setting cement plugs. Work over operations were performed in 1989 and resulted in a one month overflow test. A flow rate of 17 L/s at a temperature of approximately 100°C was encountered. Hydrochemical investigations showed a sodium-bicarbonate-chloride-water type with a TDS of 17.4 g/L. Degassing of CO₂ at the wellhead led to massive precipitation of carbonates. Due to a high organic content, a light red color of the water was observed.

The promising results of the well Blumau Thermal 1a stimulated plans for geothermal and balneological use of the resource. Geological and technical planning had to consider the establishment of a geothermal doublet and the drilling of

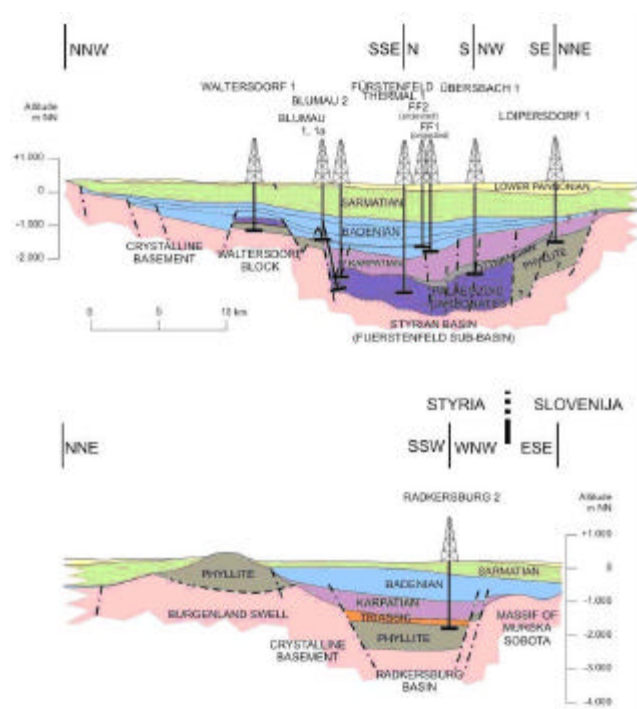


Figure 2. Geological profile.

a separate well intended for balneological use. The latter had to tap water with a mineralization much lower than of the well Blumau 1 without post volcanic CO₂ (Goldbrunner, 1993).

Well Blumau 3 which was intended for balneological use reached an end depth of 1,200 m. By single tests of perforated intervals of the 9-5/8" cemented casing productive intervals (sandy gravels) in the Sarmatian were determined in the section between 960 and 630 m. The hydrochemistry and the stable isotope content of the tested intervals differ only slightly thus proofing a uniform hydraulic system over a section of more than 300 m. The well was completed with stainless steel WWL-filters and a gravel pack (casing inside

gravel pack). The hydrochemical composition of the water is presented in Table 1. Maximum temperature at well head is 47°C; artesian flow rate is 1.5 L/s (shut-in pressure at well head is 0.2 MPa), production tests with pump were performed at a flow rate of 8 L/s and a drawdown of 130 m. The transmissivity of the aquifer is $5.4 \times 10^{-5} \text{ m}^2/\text{s}$.

Geothermal Cascade

The 250-kW geothermal project at Bad Blumau is the first geothermal project developed in Austria by the private sector following the deregulation of the electricity industry in this country. What makes the project unique besides its private ownership structure is its ability to generate electrical power and district heating for the Rogner Bad Blumau Hotel & Spa by using a low-temperature geothermal resource. Installed in the record time of less than a week, the air-cooled ORMAT[®] Energy Converter (OEC) CHP module has been in commercial operation since July 2001. With an annual availability exceeding 99%, between October 2001 and December 2002, the plant delivered 1,560,000 kWh to the local grid. The geothermal CHP module utilizes brine at ~110°C, available from a 300-m deep production well. Exiting the OEC unit at a temperature of ~85°C, the brine is then fed into the district heating system, providing heat for the Rogner Bad Blumau Hotel & Spa. The geothermal brine is returned from the district heating system and injected into a 3000-m depth reinjection well. The system is a pollution-free, unattended operating power generation module, which has avoided more than 1100 kg of CO₂ emissions over its first operating year (Legmann, 2003).

The thermal water of Blumau 3 is used for the pools in the spa (total area 2,500 m²). The spa and some outdoor pools are shown in Figure 3. Due to the favorable mineralization water treatment measures can be kept at a minimum. Production rate for the spa is 1.5 L/s and can be provided by the artesian overflow.

Table 1. Hydrochemical and Isotopic Composition of Thermal Water of the Well Bad Blumau 3 and Blumau 2 (Ionic concentration in mg/l)

Well	Bad Blumau 3	Bad Blumau 2
Depth of aquifer (m)	630 – 960	2,368 – 2,843
Sample date	1996	2003
Temperature (°C)	47	110
Sodium (Na ⁺)	345.9	5,799
Potassium (K ⁺)	3.3	129
Magnesium (Mg ⁺⁺)	2.8	6.4
Calcium (Ca ⁺⁺)	2.8	31.7
Chloride (Cl ⁻)	39.9	3,634
Iodine (I ⁻)	0.1	2.5
Sulfate (SO ₄ ⁻)	12.8	508
Bicarbonate (HCO ₃ ⁻)	883.5	7,834
Sum	1,291	17,942
Water type	Na-HCO ₃	Na-Cl-HCO ₃
Free CO ₂ (g/L)	<0.005	15.1
Deuterium (d ‰ SMOW)	-72.3	-57.5
Oxygen-18 (d ‰ SMOW)	-10.2	-7.97



Figure 3. *Bad Blumau. Spa and outdoor pools.*

For heating the spa complex and the hotels the establishment of a geothermal doublet comprising the existing well Blumau 1a and a new well named "Blumau 2" was launched. This well was designed as a vertical well 2,300 m (at surface) apart from well Blumau 1a. Blumau 2 reached the Palaeozoic dolomites at a depth of 2,360 m and encountered fractured dolomites to its end depth of 2,843 m. Due to heavy mud losses, the section in the carbonate rocks (bit diameter 5-7/8") was drilled with water. The fracturing is caused by an antithetic fault which was passed at a depth of 2,368 m by the drilling. Top of the Palaeozoic dolomites is 222 m higher at Blumau 2 than in Blumau 1a. The horizontal difference between the two borings is 1,800 m at the top of the dolomite due to the deviation of well Blumau 1a.

Long-term outflow tests showed a maximum overflow rate as high as 80 L/s at a temperature of 110°C which makes Blumau the hottest thermal water well in Austria. Artesian flow is caused by degassing. The gas/water ratio was found to be high as 9:1, the gas phase being dominated by CO₂ (CO₂ = 97%). The hydrochemical composition of the water is similar to Blumau 1a. Production logs involving density measurements showed that degassing started at a depth of 560 m and became dominating at 300 m.

The precipitation of carbonates was overcome by adding polyphosphate at a depth of 500 m. The polyphosphate results in complexation of calcium, thus preventing the development of CaCO₃. Maximum admissible artesian flow is 30 L/s showing stable hydrochemical conditions.

The thermal energy is used for heating the spa complex and the hotels (1,000 beds) since the year 2000. In 2001, an air cooled ORC turbine was installed having a net output of 180 kW of electrical power (Figure 4). As the next step, the use of the CO₂ gas, was realized at the end of 2002. The capacity is 1.5 t/h liquid CO₂ (Figure 5).

The latest development is the outdoor pool named "Vulkania" (area 1,000 m²). For this pool, water from the well Blumau 2 is directly used (flow rate 0.5-1.2 L/s). The temperature of the outdoor pool is kept stable by heating the overflow water from the pool by geothermal energy of well Blumau 2.



Figure 4. *ORC installation at well Blumau 2.*



Figure 5. *Installation for cleaning and drying CO₂ gas produced from well Blumau 2.*

Water is re-injected in the former hydrocarbon well Blumau 1a; the maximum re-injection pressure is in the order of 0.7 MPa, minimum re-injection temperature is 50°C.

Thermal output of the Blumau geothermal cascade can be summarized as follows:

Heated Object/installation	Installed Thermal Capacity (MWt)
Thermal equivalent power generation (ORC) assuming 10% efficiency	2.5
Space heating (spa centre, hotels)	3.5
Outdoor pool	1.5
Direct use (pools, water from Blumau 2 & 3)	0.1
Total	7.6

The spa was a purely private investment of €55 million (\$66 million). The project was backed up by the Styrian Government by investing €20 million (\$24 million) for the deep drillings and the improvement of the local and regional infrastructure (road construction, drinking water supply, sewage system, village restoration). The overnight stays in the region increased from 2,200 in 1995, to 37,490 in 2003 (without thermal resort), and 340 jobs in the thermal

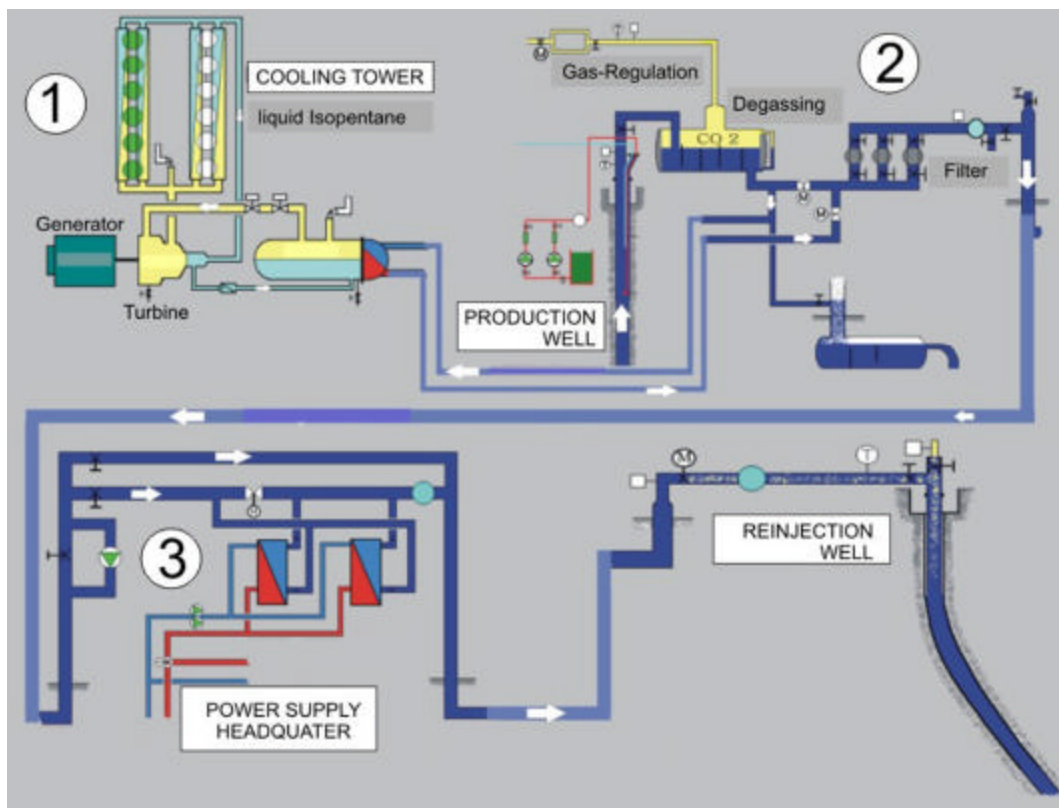


Figure 6. Blumau geothermal project: (1) ORC, (2) CO₂-gas, and (3) district heating.

resort hotel and 170 jobs in regional services have been created (Hoenig, 2005).

A schematic of the Bad Blumau project is shown in Figure 6.

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COMBINED HEAT AND POWER PLANT NEUSTADT-GLEWE, GERMANY

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INTRODUCTION

The Neustadt-Glewe geothermal heating plant was commissioned in January 1995, supplying exclusively in direct-heat transition the base load of a district heating system amounting to a thermal output of approximately 11 MWF, thus covering the demand of a major part of the town of Neustadt-Glewe. The installed geothermal capacity is 6 MW; a gas-fired boiler unit is operated to cover the peak-load. The site of Neustadt-Glewe is characterized by the hitherto deepest wells, the highest thermal water temperature and water mineralization compared to all the other geothermal plants installed in Germany by now. In 2003, the plant was extended by a power generation unit of 210 kWe gross.

This is the first geothermal electric generation plant in Germany, and uses only 98°C (208°F) water, the lowest temperature used in the world.

Neustadt-Glewe is situated in the north German basin, between the cities of Berlin and Hamburg (Figure 1).



Figure 1. Location of Neustadt-Glewe.

Since 1995, the geothermal doublet in Neustadt-Glewe provides brine at 98°C for a district heating system. The brine is produced from a 2100 to 2300 m (6890 to 7546 ft) deep sandstone aquifer. High salt contents of the brine (total dissolved solids = 227 g/L) require the use of resistant materials (e.g., titanium) for the heat exchanger equipment.

In the summer of 2003, the heating plant was extended by a binary-cycle (Organic Rankine Cycle, ORC) and in November of 2003, the first German geothermal power plant was connected to the grid, providing 210 kWe gross capacity (performance guarantee, according to Erdwärme Kraft (2003)). A measuring scheme was installed to supervise

the plant performance and to get operational data of the very low temperature ORC.

PLANT SETUP

The Neustadt-Glewe plant supplies heat and power using a parallel-series connection of power plant and heating station (Figure 2). The heating station takes priority over the power plant. The incoming mass flow rate of the brine is split and a part is fed to the power plant. The brine leaves the power plant at constant outlet temperature. The two flows, one at initial brine inlet temperature, the other at outlet temperature of the power plant, are joined upstream from the heating station. The mixing temperature should be high enough to meet the heating demand. In summertime, a minimum temperature of 73°C (165°F) is required. To meet the heating demand in wintertime, higher temperatures are necessary, amounting up to the initial brine temperature (98°C - 208°F).

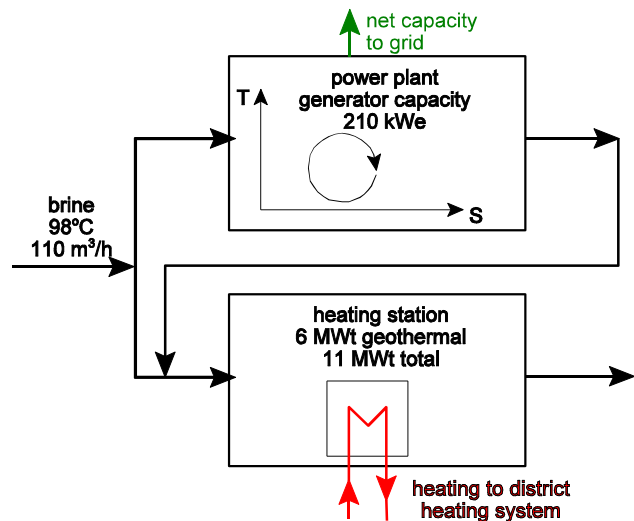


Figure 2. Combined heat and power supply in Neustadt-Glewe, parallel connection of power plant and heating station.

Unlike common combined heat and power plants with combustion or the plant setup realized with the Husavik plant, heating station and power plant are competing for the brine. The power plant is fed with variable mass flow rate of the brine at constant temperature; while, the heating station is provided with a constant mass flow rate at variable temperature.

The power plant is a simple Organic Rankine Cycle (ORC) using n-Perfluoropentane (C_5F_{12}) as working fluid. An additional pump was installed in the geothermal loop to control the mass flow rate fed to the power plant and to overcome the pressure losses of the brine in the heat exchanging equipment of the power plant. Parasitic loads in the plant include all pumps (brine pump, feed pump 10 kW, cooling water pump in cooling circuit, 15 kW), the ventilators in the cooling tower (16 kW), the cooling water pump in the well and several dosing pumps in the make-up system for the cooling water. Only the downhole pump in the production well is not included in the parasitic loads. The generator capacity and the parasitic loads are recorded as well. However, the parasitic loads are only measured as total sum.

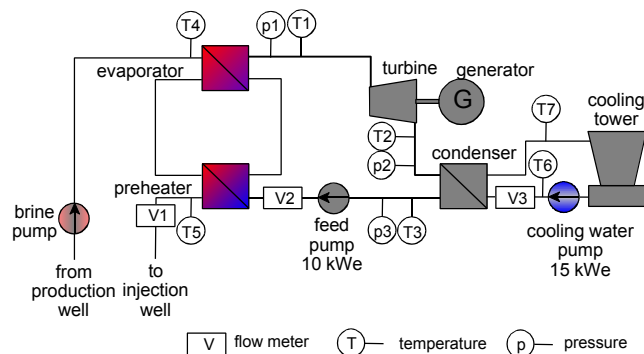


Figure 3. *Schematic setup of Neustadt-Glewe power plant with positions of measuring equipment installed in the plant.*

The setup of the plant is shown schematically in Figure 3. The figure includes the positions of the measuring equipment installed by GeoForschungsZentrum (GFZ) of

Potsdam. In total, three pressure valves, seven temperature valves and three flow meters are allowed to setup the complete energy balance of the plant as well as analysis of single components (e.g., the turbine). The outside temperature is recorded as well.

Figures 4 and 5 show the power station and the ORC turbine and condenser.

Figure 5. *ORC-turbine with new condenser.*

THE DISTRICT HEATING SYSTEM

The Neustadt-Glewe geothermal heat plant has three main components.

- Production well with speed-controlled electric submersible motor pump (depth 260 m - 850 ft) and filter house containing the control unit of the motor pump, balancing tank, coarse filter unit, nitrogen system, leakage system.



Figure 4. *Entire geothermal power station.*

- Geothermal heating plant with heat exchanger, peak load gas boiler, various equipment for the heating network water, process instrumentation and control system, control room, office rooms, demonstration hall.
- Injection well with filter house containing the injection pump (not in use), balancing tank, fine filter unit, nitrogen system, slop pit, slop collector.

The thermal water pipe is 1,780-m (5,840-ft) long and connects the wells with the heating plant.

Specific materials such as glass-fiber reinforced plastic tubes, resin-lined steel tube parts and measures such as inertisation by means of nitrogen loading were applied for protection from corrosion and precipitation.

The principle of geothermal energy use at the Neustadt-Glewe site is shown in Figure 6.

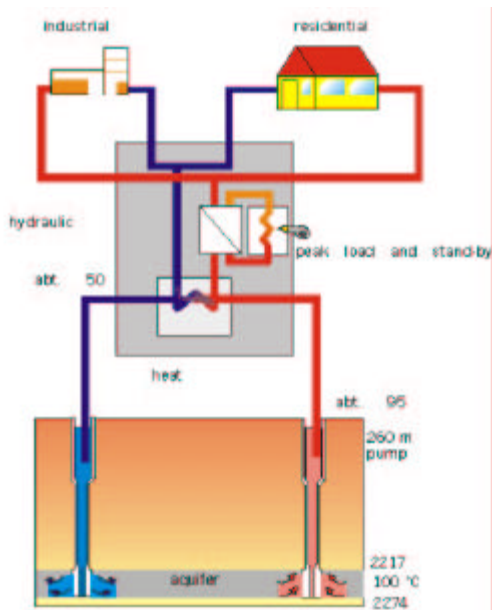


Figure 6. Schematic of the thermal water loop.

ECONOMIC AND ENVIRONMENTAL ASPECTS

The Heat Plant

The expenditures on the project including the purchase of the oil boiler unit in the residential area and the district heat supply system, as well as its extension or rehabilitation, amounted to € 9.45 million (\$11.4 million) with € 6.44 million (\$7.7 million) referring to the geothermal and heat production units.

The data on heat production in 1998 given in Table 1 allows a view of the economic situation. By the end of 1998, more than 1,300 households, 20 trade consumers and one industrial enterprise have been supplied with environment-friendly heat by the geothermal plant.

Present activities are concentrated on the optimization of the individual sections of the plant, more rational primary energy use and extension of the supply network through the connection of more heat consumers.

In Neustadt-Glewe, the emission of CO₂ was reduced by about 2,700 tons in 1997. About 1.7 million m³ (60 million

ft³) of natural gas were saved. In the course of the by now (1999) four years of operation, there did not occur any failures affecting the environment.

Table 1. 1998 Heat Production

Heat Production	
Total	15,900 MWh
That of which is geothermal	15,042 MWh
Primary Energy Source Used	
Fuel Oil	0%
Natural Gas	5%
Geothermal	95%
Percentage of the Cost Depending on Consumption	
Purchase of Gas	25%
Purchase of Fuel Oil	0%
Power - GHP	45%
Power - District Heat Supply	30%

The Power Plant

In Germany, electricity generation from geothermal heat has only since March 2000 been government-funded under the so-called Renewable Energies Act. Electricity from wind, sun, biomass and hydros have already enjoyed this privilege since 1990. The change in legislation aroused the interest in the use of geothermal energy for power production.

Bewag Aktiengesellschaft & Co. of Berlin developed ORC geothermal power plants with the following key features:

- Wet cooling towers reducing own consumption to 18-20%.
- Cogeneration because the sale of heat would increase revenues.

Bewag then looked for a project to put the know-how to good account. The geothermal power plant in Neustadt-Glewe, a little town with 8000 inhabitants located 200 km (125 miles) northwest of Berlin, lent itself well for this purpose.

The high share of geothermal heat in the overall heat volume supplied to the town of Neustadt-Glewe implied that space capacity was available for other uses (electricity generation) in the summer months and inter-seasonal periods. In addition, the smoothly operating Neustadt-Glewe geothermal plant was not subject to any geological risks, and also the operational risk inherent in the small innovative ORC plant was limited.

Another crucial factor for the project was that this 200-kWe project could be implemented within the financial framework of the originally planned 125-kWd project with air cooling towers, i.e., of € 800,000 (\$960,000) capital costs, out of which € 400,000 (\$480,000) were grant-funded. The

final costs of the project then amounted to € 950,000 (\$1.14 million).

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ERRATA

In the last issue of the *GHC Quarterly Bulletin* (Vol. 26, No. 1 - March 2005), an incorrect graph was printed for Figure 5, page 5 of the article in "Greenhouse Heating with Geothermal Heat Pump Systems" by Andrew Chiasson. The correct graph is reproduced here and can be found on our website at <http://geoheat.oit.edu/bulletin/bull26-1/art2.pdf>, where the correct version also appears.

