S-78005

File: S-78005

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GEOHERMAL SOURCEBOOK
SECTION 2.0 - PLANT CONTROL
Subcontract No. K-1232

Submitted to:

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S-78005

April 10, 1978

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2.0 PLANT CONTROL

2.1 Typical Control Requirements Imposed On A Geothermal Power Plant

This Section discusses (1) requirements for control of an individual power plant for both base loaded or load following plants, (2) operations during upset conditions, and (3) the degree of automation which may be applicable to a geothermal power plant.

2.1.1 Normal Transients

Normal transients, as used in this section, are normally expected load changes and the ability of the electric power system to maintain frequency within the system, following these load changes.

When a power system is operating at normal frequency, the generation and loads are matched. Any increase or decrease of load must be followed by a corresponding change in generation to match the new load condition and maintain normal frequency. When generation is inadequate for the loads, the system frequency will decline. When generation exceeds the load, the system frequency will increase.

The system load results from consumption of power by the utility company's customers which varies constantly, and immediate generation adjustments are required to match the varying loads in order to maintain system frequency. This is normally accomplished by load frequency control or automatic dispatch equipment (A. D. E.)

A.D.E. consists of a digital computer which is used to continuously monitor the system loading conditions, determine the most economical allocation of generation between units, and send control impulses to load the units to the desired values. A.D.E. is normally applied only to load varying plants in very large power systems (infinite power systems) and is not considered a good application for a geothermal plant because in these large systems a geothermal power plant is normally base loaded. Therefore, A.D.E. will not be further discussed with reference to geothermal plant control.

When a plant is required to generate at a constant power output value with no regard to the variances in the system's load, a kW controller is normally applied and is discussed in (a) below.

If a geothermal power plant must follow the load then a load-frequency type of control is applied and this type of control is discussed in (b) below.

(a) Base Load Plants

A base load plant is one in which the generators produce constant power output without regard to the power system loads.

Base loading is the most common type of application for a geothermal power plant because by the nature of the geothermal resource, it is not convenient to vary resource supply. Also, in comparison to a fossil fuel plant the geothermal plant is more economical; hence, it is desirable to obtain as much energy as possible from geothermal plant and let the fossil fuel plants follow the system loads.

When a geothermal power plant is part of an "infinite power system" the power plant is normally base loaded at or near the maximum output rating of the generator. The PGandE system is an example of an "infinite power system" with respect to The Geysers geothermal units because total system capacity is large (12,000 MW) in relation to an individual geothermal power plant unit capacity (100 MW).

In a base loaded plant, the kW controller is normally applied and will continuously monitor the output value of the generator and compare that value to the value set on the kW controller. If these values are not equal, the kW controller will send a correction signal to the governor to cause an adjustment in the main turbine throttle valve.

The kW controller has two main functions. The first is to cause adjustments to account for resource supply differences or plant variances in order to produce a constant kW output. In this regard the kW controller indirectly varies only the position of the main turbine throttle valve. If the vapor supply to the turbine is less than required for the preset load, the kW controller will adjust vapor supply to meet the load. The maximum the kW controller can accomplish, is to fully open the valve which will result in the maximum generation output corresponding to the available resource supply.

Secondly, during upset conditions the kW controller serves to automatically reduce vapor supply during plant equipment failures which would require a reduced output. An example of this function can be illustrated by considering the loss of a hot well pump in a flashed steam plant. The kW controller can be set to automatically reduce vapor supply to the turbine in this event to prevent a high water level condition in the condenser hot well which would trip out the entire unit.

(b) Load Following Plants

A load following plant is defined as a plant in which the regulation of the power output of the electric generator responds to the changes in the system loads.

The system in which a geothermal power plant is installed may dictate the application of a load following plant. For example, the plant may be a single unit in a system or it may be a major unit of a system. In this application the speed of the generator must be controlled. The turbine governor does control the speed of the turbine, but not with sufficient accuracy. The typical governor droop is 5%, or in other words, between full load and no load the frequency would vary 5%. A frequency controller is normally added in order to achieve the higher degree of system frequency control required.

Frequency controllers are designed to control the speed of the turbine to maintain a desired frequency by comparing the generator frequency with the controller's preset value. As mentioned earlier, when a power system is operating at normal frequency, the generation and loads are matched and thus when the generator is operating at the required frequency the desired power output will be maintained.

With the addition of a frequency controller, a the governor control system can maintain the system frequency within ± 0.05 Hertz. This high degree of control can still result in a time clock error of 1.2 minutes per day. When a higher degree of clock time accuracy is required, the addition of a clock time control to the frequency controller is common. This clock time controller will compare system time to actual time. The time error is constantly integrated by the controller and when the system time is outside the preset limits it will cause the governor system to correct the system time. Actual time for comparison is normally accomplished by a separately powered quartz time clock.

2.1.2 Upset Conditions

An upset condition in this section is defined as an abnormal condition sensed by one or more of the plant protective devices.

During upset conditions, lockout operation or non-lockout operation will normally occur. These two types of operations are discussed below:

2.1.2.1 Lockout Operation:

A lockout operation is defined as an operation which will shut down the entire plant and disconnect the plant from the system.

A lockout operation is basically caused by an upset condition within the plant which is of such serious consequence that a complete plant shutdown is necessary.

a) A lockout operation will cause all of the following typical actions to occur:

1. Trip the exciter field breaker.
2. Trip the turbine main stop valve.
3. Trip the outgoing line power circuit breakers.
4. Trip all auxiliary main power circuit breakers.
5. Trip the cooling water flow solenoid valve.
(Steam Plant Only)
6. Trip stop valve motor operators in the steam supply.

b) The following are typical conditions which will initiate a lockout operation and activate a generator shutdown lockout relay:

1. Generator ground fault
2. Generator low excitation
3. Generator current differential
4. Other in-plant current differentials
5. Generator bearing over-temperature
6. Main step-up transformer sudden pressure
7. Activation of a manual shutdown

c) The following are typical conditions which will activate a turbine lockout relay:

1. Generator CO₂ injection
2. Turbine-generator high vibration
3. Turbine overspeed
4. Turbine bearing over-temperature
5. High condenser pressure
6. Low condenser fluid level
7. High condenser fluid level
8. Loss of hot well pumps in flashed steam plan or feed pumps in binary plants
9. Main steam stop valve closes
10. High-pressure steam separator high water level
(Flash system only)
11. Low-pressure steam separator high water level
(Double flash system only)
12. Activation of a manual shutdown

NONLOCKOUT

2.1.2.2 Non-Lockout Operation:

A non-lockout operation is defined as an operation which will separate the plant from the outgoing power lines, but keep the turbine-generator turning and supplying power to the auxiliaries. This operation is basically caused by an upset condition external to the plant of such serious consequence that separation of the plant from outgoing lines is necessary.

A non-lockout operation will trip the outgoing line power circuit breakers.

The following are typical conditions which will initiate a non-lockout operation and activate a generator non-lockout relay:

1. Reverse power
2. Generator under frequency
3. Activated phase balance relay
4. Generator phase over-current
5. Generator over-voltage
6. Generator winding over-temperature
7. Auxiliary under-voltage
8. D. C. source under-voltage
9. Main step-up transformer winding over-temperature
10. Main transformer ground over-current

2.1.3 Degree of Automation

Four possible degrees of automation of plant operation are as follows:

2.1.2.1 Semi-Automatic Plant With A Roving Operator:

In this case the plant has no permanent staff and is unmanned except for sequential visits by a roving operator. This type of operation is applicable where the power output of an individual unit is of minor importance to the entire power system and the loss of its output can be tolerated until the downed unit is discovered by the roving operator.

All the units are designed to operate in a failsafe mode, that is, each generating unit is self protected to sense an equipment failure or potential damage (such as a generator bearing over-temperature) and automatically shut itself down. Upset conditions causing plant shutdown are discussed in Paragraph 2.1.2 above.

A common feature of this type of plant is the installation of an annunciator system with a "first in alarm" capability. This type of annunciator is very important in troubleshooting a downed unit.

Another common feature in this type of plant is the inclusion of an automatic data logging system for selected points. This is not a strict requirement since a roving operator can take readings during his visit, but this feature will allow for important readings to be recorded between the operator visits.

2.1.3.2 Urgent and Ordinary Alarm System to a Distant Control Center:

This type of system is a variation of semi-automatic operation with a roving operator as discussed above. The plant alarms are brought into a central control area, so that an abnormal condition is known immediately and an operator can be dispatched to that plant. This system provides the advantage that down time of a plant can be reduced or avoided due to immediate knowledge of an abnormal condition.

An urgent alarm is one which requires immediate attention by an operator, such as a unit shutdown. An ordinary alarm is one of a lesser urgency in which a monitored value is out of its normal range and should have the attention of an operator as soon as possible to prevent more serious occurrences including a unit trip.

It is of interest that the Pacific Gas and Electric Company's Geysers installation started with a roving operator approach. Recently, however, PGandE has installed an alarm system in a central location such as described above. This alarm system was installed in order to minimize the down time of the Geysers' plants.

2.1.3.3 Local Plant Operator:

In this case trained operators are assigned to each plant for 24 hours a day manning. The presence of trained personnel at the plant during both normal and abnormal conditions will result in the highest degree of plant availability. In a manned plant a control room with a main control board is a normal inclusion. This board normally contains the control devices for selected plant equipment, data acquisition read-outs, alarm annunciation, and synchronizing devices.

2.1.3.4 SCADA (Supervisory Control and Data Acquisition)

When it is desirable to operate a plant from a remote location, a SCADA system would be applicable. The remote location could be a central dispatch center where operators have a power transmission system and various generation plants under their control. The use of a SCADA system at a remote location approaches having the same degree of operating capability achieved with a local operator as discussed above.

The most important function of a power plant data system is to provide the operator with essential information regarding plant operation. A SCADA system can recognize and give priority to reporting information and critical events. Such essential information is reported automatically, while other data is left for operator demand.

A basic SCADA system consists of a cathode-ray-tube (CRT) display module, a pushbutton keyboard, a control processor, a printer, and remote stations.

The CRT provides an automatic visual display of all alarms and additionally permits the operator to call up any plant information he desires.

The pushbutton keyboard allows the operator to converse with the power plant system. Through this keyboard he is able to open or close breakers, raise or lower equipment set points, review monitored breaker positions or metered values, clear alarms, or cause information to be printed.

The printer will automatically print all alarms, or control actions performed by the operator. Display values can be printed on a routine basis or upon operator request.

Remote stations gather data and control equipment points in their defined area. The remote stations electrically link their area equipment points to the control processor.

The control processor is a preprogrammed computer which electrically links the remote stations to the rest of the SCADA system.

The cost of SCADA systems is now such as to make SCADA an attractive method of power plant control. As with any design, the economics of a SCADA system should be examined to determine the desirability of application.

2.2 Control of a Plant Using A Geothermal Steam Source

2.2.1 System Limitations

Major factors limiting the operation and control of a plant using a geothermal steam source are (1) the available steam supply pressure, (2) the need to remove and dispose of geothermal condensate from the condenser and (3) the need to remove and dispose of noncondensable gases from the condenser.

2.2.1.1 Steam Supply Pressure

Steam pressure from a geothermal source is determined by the characteristics of the resource. If the wells produce dry steam, the nominal pressure level of the field will be used to establish the turbine entry design pressure. The slight variations in pressure that may occur between wells is balanced out by variations in pressure drop in the lines connecting the wells to the central gathering point.

2.2.1.2 Condensate Removal and Disposal

For efficient turbine operation the steam must be discharged from the turbine at a low absolute pressure and then condensed. Unlike a thermal power plant, geothermal condensate cannot be reused to make steam and in most plant designs, is used for make up to the cooling water system with any excess being disposed of as appropriate.

A commonly used type of condenser in geothermal plants is the direct contact condenser which may be either the low level type or the barometric type.

A low level direct contact condenser is illustrated in Figure 2.2-1. Exhaust from the turbine flows directly into the condenser where it is mixed with a spray of cooling water to cause condensation. The mixture of cooling water and condensate is removed by the hotwell pump which must be able to pump from the low atmospheric pressure (vacuum) of the condenser to the top of the cooling tower. The noncondensable gases are cooled in a special section of the condenser before being drawn out.

The barometric type direct contact condenser is illustrated in Figure 2.2-2. The exhaust from the turbine is piped to a point near the bottom of the condenser body but above the normal water level. Cooling water flows in the top and falls through a series of baffles while it mixes with and condenses the steam. The mixture of cooling water and condensate flows through the vertical pipe to the hot well. The water level in the condenser is determined by the head of water that can be maintained by the vacuum of the condenser. In this arrangement the hot well pump is only required to pump from atmospheric pressure in the hotwell to the top of the cooling

tower. The noncondensable gases are cooled as they flow upward through the body of the condenser before being drawn out.

Steam may also be condensed by heat exchange in a surface type condenser. In this type the cooling water is pumped through tubes within the condenser and the exhaust steam is condensed in the space around the tubes. After passing through the tubes the cooling water flows to the cooling tower. This type of condenser does not allow the noncondensable gases to dissolve in the cooling water so that the majority of the gases are removed under controlled conditions through the noncondensable gas removal system. The amount of condensate produced normally exceeds the amount evaporated in the cooling tower. The excess amount will overflow the cooling tower basin and requires disposition. Due to the build up of impurities the condensate usually cannot be allowed to flow into surface streams. The only environmentally acceptable method for disposal is by injection into the earth through special wells. Due to the corrosiveness of the condensate, all piping and equipment contacted by it must be made of 316 stainless steel.

2.2.1.3 Noncondensable Gas Removal

Steam derived from geothermal wells usually contains noncondensable gases in amounts varying to 10% or more by weight of the steam flow. Generally, if the noncondensables exceed 10% by weight of the steam flow, the source is not viable as a steam supply. Consideration must then be given to using an indirect heat transfer scheme to prevent plugging of the formation with insoluble chemicals when the CO_2 is released. This is covered elsewhere in this text.

The noncondensable gases normally consist mainly of carbon dioxide, hydrogen sulfide and nitrogen with trace amounts of other gases. If these gases are not removed from the condenser they will destroy its vacuum. For gas content up to 5% by weight of steam flow the gases are usually pumped from the condenser in two stages by steam jet gas ejectors. If the gas content is between 5 and 10% by weight the first stage of pumping will usually be by centrifugal compressor followed by a second stage of steam jet gas ejectors. Between stages steam is condensed and the temperature of the gases is controlled by cooling water in an intercondenser. The gases will be passed into the atmosphere unless they contain objectionable amounts of hydrogen sulfide which must be removed. Methods have been developed for removing most of the hydrogen sulfide from the noncondensable gases.

2.2.2 Control Methods and Capabilities

The following control methods are those that have been commonly used in geothermal power plants. They may be changed in the future as new methods become available.

2.2.2.1 Steam Turbine Speed and Load

The speed and/or load of the turbine-generator is controlled by the governor operated steam valves. The type of governor control will depend on whether the plant will operate as a base load plant or a load following plant. This is discussed in detail in Paragraph 2.1.1.

If the generator is tripped off the line the turbine will immediately speed up. When events require that the turbine be tripped as the result of overspeed or any other cause, it is necessary to stop the flow of steam into the turbine. Since the governor control valve is not a tight shutoff valve and is not designed for rapid closure, special stop valves are required in all steam supply lines. A common form of this valve is a swing check installed to close with flow and to be held open by a hydraulic actuator. This type of valve can be closed rapidly and completely to stop all steam flow to the turbine.

Figure 2.2-3 shows the cross section of a typical stop valve with internal bypass valve. During turbine start-up and at low load the control valve may be opened fully and the steam flow controlled by the bypass valve in the stop valve.

2.2.2.2 Condenser Absolute Pressure/Vacuum System

The absolute pressure in the condenser is determined by the capability of the noncondensable gas removal system and the heat transfer capability of the condenser cooling system.

Before start-up of the turbine the noncondensable gas removal system is started to evacuate air from the condenser and produce the low absolute pressure required to operate the turbine at design conditions. When the turbine is operating and steam is flowing into the condenser, the vacuum is controlled by throttling the flow of cooling water into the condenser. During turbine operation the noncondensable gas removal system contributes to the vacuum only by removal of noncondensable gases from the condenser.

2.2.2.3 Condenser Level

In a direct contact condenser the condensate plus the total flow of cooling water must be pumped from the condenser to the

cooling tower to maintain a constant level in the condenser. If the condenser is of the surface type only the condensate must be pumped out to maintain the level. In both cases it is important to maintain the condenser level within limits. A high level will reduce the condenser efficiency while a low level will starve the condensate pump and possibly damage it.

The normal method of controlling condenser level is by throttling a flow control valve in the discharge line of the hotwell or condensate pumps by a signal from the level controller. In some designs a bypass valve permits return of the condensate pump discharge back to the condenser to control level or to prevent pump overheating during low flow conditions. If the level in the condenser reaches either an extreme high or extreme low setting, the turbine-generator unit is tripped.

2.2.2.4 Auxiliary Cooling Controls

Cooling water is required to cool a variety of auxiliary equipment within the plant. This includes the inter- and aftercondensers of the noncondensable gas removal system, generator cooling medium, lube oil, air compressors and the plant air conditioning system.

- a. The intercondenser and aftercondenser require cooling water to condense the steam carryover from the condenser and the steam from the steam jet gas ejectors. In most systems this flow is set manually since the amount of steam to be condensed is relatively constant and independent of load.
- b. It is necessary to control the lube oil temperature to hold the oil viscosity in the proper range. This is usually done in a shell and tube heat exchanger. Since geothermal condensate tends to include finely suspended solids, it is desirable to pass the cooling water through the tube side of a shell and tube heat exchanger at a constant velocity sufficient to minimize deposition of solids in the tubes. To maintain heat transfer capability the tubes may be rodded out if they start to become plugged. A bypass around the exchanger is used to control the oil flow rate through the exchanger and to maintain the desired temperature of the total flow of oil.
- c. The generator is normally cooled by the flow of a gas through its windings. This gas will be either air or hydrogen depending mainly on generator size. The gas is cooled by circulation of cooling water through tubes mounted in the generator gas cooling stream. The cooling

water flow is set manually to maintain temperatures within the generator at full load and is not automatically controlled.

- d. Both the air compressors and the air conditioning system have cooling water passages that could be plugged with solids from geothermal condensate. Therefore, a closed fresh water cooling system is used consisting of circulating pumps, piping, heat exchanger, surge tank and treated water. The fresh water is cooled by geothermal condensate cooling water passing through the tube side of the heat exchanger at constant velocity while the flow of the treated water is controlled to maintain the temperature of the system.

2.2.3 Plant Interface with Supply and Injection System

2.2.3.1 Steam Supply

Before a geothermal power plant can be started the wells must be started and brought up to normal flow conditions to obtain clean steam flow. This requires a period of time with the steam flowing through automatic pressure control valves to atmosphere. When the plant is brought up to load the pressure control valves will automatically close and all steam will be flowing to the turbine. When a plant shutdown occurs the pressure control valves will reopen to protect the piping.

The automatic pressure control valves are backed up by pressure relief valves designed to handle well flow if the control valves fail to open. If the plant is to be shutdown for a long period of time, the wells will be manually shut off. When the plant is ready to re-start, the wells will be gradually brought up to flow to clear them of debris.

2.2.3.2 Protection of Plant From Excessive Moisture in the Steam

A plant that is fed dry steam from the wells is not usually endangered by excessive moisture in the steam. The condensate that forms in the pipelines is drained off by steam traps. An inline moisture separator is installed in the pipeline before the line enters the turbine building to collect condensate and solid matter that may be coming through the pipeline.

2.2.3.3 Effect of Turbine Trip and Load Variation on Steam Supply System

Geothermal wells cannot be started or stopped instantly. Therefore, the steam supply control system is set up so that a turbine trip does not have a detrimental effect on the wells. The immediate effect of a turbine trip is an increase in pressure in the steam supply system which will cause pressure control valves to open to prevent an excessive pressure rise and permit the steam to continue flowing from the wells.

2.2.3.4 Operation of the Injection System

The portion of the condensate that is not evaporated or used as make-up in the cooling tower will overflow from the cooling tower basin as blowdown into a collecting pond. To prevent this from causing stream or surface pollution, it is normally returned to the aquifer via injection wells located so the cool return water will not thermally degrade the producing geothermal wells. The operation of the injection pump is controlled by a level controller in the pond. Tower blowdown is necessary to keep solids from building up in the cooling water circulating stream. When the steam condensation is insufficient it may be necessary to add surface water to the tower basin to provide blowdown.

2.3 Control of A Plant Using A Flash Steam System

2.3.1 System Limitations

The major factors that limit the operation and control of a plant using a flash steam system are (1) the available flash steam pressure or pressures, (2) the need to remove and dispose of geothermal condensate from the condenser and (3) the need to remove and dispose of noncondensable gases from the condenser.

2.3.1.1 Steam Supply Pressure

The steam pressure from a flash steam system is determined by the characteristics of the resource and the number of flash stages chosen. The most common arrangement is to use a double flash such that there is a dual steam inlet to the turbine at two different pressures and temperatures. By using this double flash system, it is possible to reduce the hot water requirement from the wells by approximately 20-30 percent of the quantity required by a single flash system.

2.3.1.2 Condensate Removal and Disposal

This system is identical to that for a plant using a geothermal steam source. Refer to Paragraph 2.2.1.2.

2.3.1.3 Noncondensable Gas Removal

This system is identical to that for a plant using a geothermal steam source. Refer to Paragraph 2.2.1.3.

2.3.2 Control Methods and Capabilities

The following control methods are those that have been commonly used in geothermal power plants. They may be changed in the future as new methods become available.

2.3.2.1 Steam Turbine Speed and Load

This control is similar to that for a plant using a geothermal steam source except for the dual pressure steam entry to the turbine and the duplicate control valves. Refer to Paragraph 2.2.2.1.

2.3.2.2 Condenser Absolute Pressure/Vacuum System

This system is identical to that for a plant using a geothermal steam source. Refer to Paragraph 2.2.2.2.

2.3.2.3 Condenser Level

This system is identical to that for a plant using a geothermal steam source. Refer to Paragraph 2.2.2.3.

2.3.2.4 Auxiliary Cooling Controls

These systems are identical to those for a plant using a geothermal steam source. Refer to Paragraph 2.2.2.4.

2.3.2.5 First Stage Pressure Control

The controls for a two stage steam flash system are shown in Figure 2.3-1. A mixture of hot water and steam flows from

each well through a hand controlled flow control valve and is delivered to the first stage separator (flash drum). The pressure in the drum is normally controlled at primary steam pressure by operation of pressure control valve PCV-1A through which steam passes to the moisture separator and thence to the turbine. If the first stage drum pressure cannot be controlled by the flow of steam to the turbine, pressure control valve PCV-1B will open to release steam to the atmosphere. If PCV-1B cannot control pressure at a level that is safe for the flasher, the pressure safety valve PSV-1 will open to release additional steam.

2.3.2.6 First Stage Flash Drum Level Control

Water level in the first stage flasher must be maintained at a level that will both prevent steam flow from the bottom of the drum and water flow into the steam line. A level control in the flash drum controls level control valve LCV-1A to allow water to flow into the second stage flasher. If the flow rate to the second stage flasher is not sufficient, the level in the flasher will rise and the controller will then open drain valve LCV-1B to allow water flow to the collection pond.

2.3.2.7 Second Stage Pressure Control

The steam pressure in the secondary flash drum is controlled by releasing steam to atmosphere when the secondary steam

pressure exceeds that required for secondary entry to the turbine. A pressure safety valve protects the flash drum from excessive pressure should the pressure control system fail.

2.3.2.8 Second Stage Flash Drum Level Control

The water level in the second stage flasher must also be controlled to prevent steam flow to disposal and water flow in the steam line. Level controller LIC-2 will operate valve LCV-2 to allow excess water to be pumped to the injection well. A high level in the second stage flash drum or moisture in the pipeline to the power plant will initiate a turbine trip.

2.3.2.9 Flash System Alarm and Turbine Trip Functions

The following alarms and trips are normally provided for the indicated abnormal conditions in a flash steam system.

1. First stage flash drum low pressure alarm
2. First stage flash drum high level alarm
3. First stage flash drum high level turbine trip
4. Second stage flash drum low pressure alarm
5. Second stage flash drum high level alarm
6. Second stage flash drum high level turbine trip

2.3.3 Plant Interface With Supply and Injection System

2.3.3.1 Steam Supply

Before a geothermal power plant can be started the wells must be started and brought up to normal flow conditions to obtain clean steam flow. This requires a period of time with the steam flowing through the automatic pressure control valves to atmosphere and the excess water flowing into a pond at the wells. After the well operation becomes stable, the water and steam flow is gradually shifted to the high pressure steam flasher. The excess water from the high pressure flash drum flows to the low pressure flash drum. Steam is vented to atmosphere from both flash drums by automatic pressure control valves. When the plant is brought up to load the pressure control valve will automatically close and all steam will be flowing to the turbine. The automatic pressure control valves are backed up by pressure relief valves designed to handle well flow if the control valves fail to open. If the plant is to be shutdown for a long period of time, the wells will be manually shut off. When the plant is ready to re-start, the wells will be gradually brought up to flow to clear them of debris.

2.3.3.2 Protection of Plant From Excessive Moisture in the Steam

A plant that is fed steam from a flash steam system is extremely vulnerable to excessive moisture being fed into the

turbine. To guard against this, the turbine is tripped out if a high water level occurs in either of the flash drums.

2.3.3.3 Effect of Turbine Trip and Load Variation on Steam Supply System

Geothermal wells cannot be started or stopped instantly. Therefore, the steam supply control system is set up so that a turbine trip does not have a detrimental effect on the wells. The immediate effect of a turbine trip is an increase in pressure in the steam supply system which will cause pressure control valves to open to prevent an excessive pressure rise and permit the steam and water to continue flowing from the wells.

2.3.3.4 Operation of the Injection System

In addition to the excess condensate from the cooling tower, a flash steam system also has the unflashed geothermal water from the flash drums. To prevent this from causing stream or surface pollution, it is normally returned to the aquifer via injection wells located so as to minimize thermal degradation of the producing geothermal wells. The operation of the injection pump is controlled by a level controller in the pond.

2.4 Control of Binary Systems

2.4.1 Basic Control Methods Available

The basic practical heat exchange methods and configurations available for application in a binary cycle geothermal plant are identified below.

There are minor variations on these basic cycles such as the use of economizers, hydraulic turbines, mixed steam and binary turbines, etc. with a view to extraction of maximum amounts of energy. Although these are all thermodynamically possible, the practical economic advantages are questionable.

2.4.1.1 Shell and tube exchangers with kettle type vaporizer, liquid brine throughout train. Brine is pumped from wells through the exchanger train to injection wells.

2.4.1.2 Shell and tube exchangers with vaporization in the series train (no kettle type vaporizer, liquid brine throughout train) Brine is pumped from the wells through the exchanger train to injection wells.

2.4.1.3 Shell and tube exchangers as above but employing steam separators with steam-binary fluid as one element of exchanger train. The assumption here is that no pump is required and the geothermal fluid is flash flowed from wells through the heat exchange train to injection wells.

2.4.1.4 Direct contact exchangers in which the binary fluid is heated by direct contact with the brine. The brine is pumped from the wells in this case.

2.4.2 Discussion of Basic Process Control Methods

2.4.2.1 Pumped Brine-Binary Cycle Using Kettle Type Vaporizers
(See Figure 2.4-1)

a) Pressure Control

When turbine load increases and an increased quantity of working fluid (for example isobutane) is required, the pressure recording controller (PRC) would sense a drop in pressure which in turn would call for an increased flow of brine. The PRC valve would open and more heat would be added to increase vaporization to restore pressure.

b) Vaporizer Level Control

Level control in the vaporizer would sense a drop in level with increased vapor drawn off and call for the working fluid feed pump turbine to increase in speed producing more flow to vaporizers to hold level. It is possible that a two-element vaporizer feed system similar to a two-element boiler feed water system would be required, particularly if the working fluid level has a tendency to "swell" temporarily rather than decrease with increased vaporization. Control devices to compensate for this are readily available but not shown here.

c) Superheat Control

For minimum interaction between controls the scheme as shown in Figure 2.4-1 would accomplish this. A three-way valve throttles to permit more or less vaporized working fluid through the superheater exchanger. Because a three-way valve always presents a constant flow area to the process stream, very little interaction would be experienced on the PRC loop.

Inherently there is good self regulation built into this system in that if load is increased, calling

for more brine flow, the superheater heat load is increased also as brine flow is in series with vaporizer. Approximately the same proportion of series flow through the series port of 3-way valve to bypass flow would prevail. Thus the control valve would not be required to move drastically to a new position, making for stable control.

2.4.2.2

Pumped Brine Binary Cycle Using Shell and Tube Exchangers (See Figure 2.4-2)

This exchanger arrangement does not employ a kettle type vaporizer and vaporization occurs in the shell of the vaporization section of exchanger train.

a) Pressure Control

Pressure control is maintained on working fluid to main turbine by controlling the set point of the speed controller of the working fluid feed pump turbine which in turn controls the head on the feed pump.

b) Level Control

No level control is possible as is the case when using a kettle type vaporizer.

c) Superheat Control

Superheat control in this case is by throttling the brine outlet to reinjection.

With indeterminate fouling of exchangers, there is no guarantee that vaporization will always occur in the exchanger designated as the vaporizer. The quality of the vapor may be such, that some liquid may be carried over and slug the turbine. A knock-out drum must be provided to prevent this occurrence.

An automatic drain or level control from this drum is required to transfer liquid working fluid carry-over to condenser inlet.

2.4.2.3

Flashed Brine Binary Cycle with Reboiler Type Vaporizer

(See Figure 2.4-3)

a-1) Flash Drum Pressure Control

If the well fluid is such as to flash flow without pumping, this arrangement should be used.

The controls on flash tank are similar to a single-flash steam cycle.

The flashing pressure is determined by the setting of PIC which, in normal operation, permits the flashed vapor to provide heat to vaporizer and superheater.

If, however, there is a trip on the generator turbine, with consequent stoppage of working fluid flow, the temperature controller on superheated vapor would tend to close the temperature control valve and flash pressure would tend to rise. The pressure indicating controller (PIC) (on split range positioners) would then cause the vent valve to open to maintain flash pressure.

a-2) Working Fluid Pressure Control

This control throttles the amount of brine which is bypassed to maintain the required heat to vaporize

the working fluid at desired pressure. This pressure control valve can also be controlled during start-up by a pressure control as shown. Which controller operates this valve is determined by a selector relay which smoothly transfers control to the controller having the higher output pressure.

b) Level Control

In all operation modes, the level control on flash tank holds a liquid level by throttling the pumped outlet.

c) Superheat Control

Heat is added to the vaporized working fluid by throttling a three-way valve in vapor line to superheater. To satisfy temperature set point, the valve throttles to either put flow through port in series with exchanger or through port which bypasses exchanger.

This type of control should provide minimum interaction between superheat and pressure control.

2.4.2.4

Flashed Brine with Shell and Tube Exchangers (no reboiler)

Not shown but readily apparent, the flashed binary cycle could incorporate shell and tube exchangers rather than reboilers and the controls would be similar to that described for 2.4.2.2. Flashed steam would be used in superheat and vaporizer exchangers.

2.4.2.5

Direct Contact Binary Cycle (See Figure 2.4-4)

Depicted here is one type of direct contact exchange process in which the binary working fluid is placed in direct contact with the brine in a trayed contactor column. Brine enters the top of the column, working fluid enters at the bottom and fluid flows are counter-current.

Because of mutual solubility, some water vapor leaves the top of the column with the working fluid and some working fluid leaves with the brine at the bottom of the column.

Controls and process equipment must be provided to minimize the amount of expensive working fluid, either leaving the process with the noncondensable gases, or returning with the brine that is reinjected.

Without describing the mathematical process calculations, basically the column functions as follows:

The bottom trays provide preheating of the working fluid. Near the top there is a trayed section where working fluid boils. The last few top trays provide superheating of working fluid.

a-1) Column Pressure Control

Pressure of vapor leaving contactor column is controlled by throttling the amount of brine leaving the bottom of column, or in effect the amount of heat transferred to a demand flow quantity of binary working fluid.

a-2) Flash Vapor Vacuum Pressure Control

Condensing steam will tend to form a vacuum in flash vapor condenser.

However there will probably be some working fluid vapors at their partial vapor pressure at condensing steam temperature. These are withdrawn from condenser on PIC control. Depending on type of blower or compressor used, pressure can be maintained. One method shown here is spill back from discharge to suction of compressor.

a.3) Accumulator Pressure Control

Carried in with the brine from the wells will be the noncondensable gases typical of a geothermal well. These would tend to pocket in the accumulator if not drawn off. Accordingly it may be necessary to either simply vent these gases under accumulator pressure control or provide a compressor to do so. Shown here is a typical suction pressure controller for a compressor.

b-1) Column Level Control

At the tray position where boiling occurs, the level control operates either: a control valve in the discharge line of the working fluid feed pump or alternatively resets the speed control of the turbine driver for the feed pump as in previous descriptions.

b-2) Accumulator Level Control

Condensed out with the working fluid would be the water that is carried out in equilibrium with the vaporized working fluid from the top of the con-

tractor column. An interface level control is required to separate the layer of water and return it to reinjection as shown.

b-3) Flash Drum Level Control

Brine in passing through PRC control valve will flash into the flash drum. Working fluid vapors will flash at the top of this drum, and the remaining liquid will be level controlled to re-injection.

b-4) Flash Vapor Condenser Level Control

Flashed steam containing the same working fluid vapors that enter the flash drum leave the top of the flash drum and are condensed in flash vapor condenser. The condensed liquid is level controlled back to the accumulator.

b-5) Level Control on Aftercooler Condenser

Carried with the noncondensable gases at the condensing temperature in the accumulator will be some working fluid vapors in the ratio of its partial pressure to total condensing pressure.

If these noncondensable gases were simply vented an appreciable amount of working fluid would be wasted to the atmosphere.

However to condense the working fluid vapor requires a colder temperature than that obtained in the turbine condenser. It is apparent that the coldest cooling water supply temperature to the main condenser, would not be adequate as the gases leaving the accumulator are already at a reasonable approach to CWS temperature.

It then becomes necessary to provide either refrigerated water to the aftercooler condenser or refrigerant directly in the tubes of the said condenser. A refrigeration system for the cooling water is shown on Figure 2.4-4. The condensed working fluid is collected in a boot on the noncondensable condenser separator and level controlled back to accumulator.

c) Superheat Control

Automatic control of superheat temperature is probably not necessary. Process design would provide sufficient inlet trays to provide the degree of superheat required.

2.4.3

Common Control Systems

It is apparent from the above descriptions of binary processes and their control philosophy, that some basic parameters are common to all of the systems. These are as follows:

2.4.3.1

Controlled Start-up and Shutdown

For maximum protection against shock to the wells and producing strata, it is imperative that brine flows should be gradually increased to design capacity. Abrupt shut-in of brine flows should never be permitted, such as could occur in the event of an emergency shutdown of working fluid flow occasioned by a working fluid side-staoppage, by a turbine-generator trip, or for any other failure on the working fluid side. Hence, bringing a geothermal well system either up to capacity, or decreasing well flow to a shut in condition is a matter of hours, similar to considerations in 2.2.3.1 above.

2.4.3.2

Consideration for Brines with High CO₂ Content

For brines which contain a high proportion of CO₂ in the noncondensable gases, it is mandatory that flowing brine

pressures be kept high enough to prevent flashing of brine in the brine loop and preclude deposition of calcium carbonate in equipment and piping, with its consequent fouling and solids deposition.

2.4.3.3

Emergency and Start-up Brine Bypass System

It should be noted that each binary process system should have a brine bypass line and pressure control loop which automatically bypasses geothermal water to reinjection. This pressure controller in effect is attempting to control well head pressure.

During start-up the set point of this control is gradually lowered manually or by ramp control to match the wellhead with flow pressure curve at demand operating point. When brine flow rate is at or approaching plant design flow rate through the bypass loop, the brine is gradually introduced into process loop.

The set point of the control in normal operation is slightly higher than design operating pressure at the same point of measurement, such that integral controller action will gradually close this valve with increase of process flow, and permit small variations in head or

pressure by the process controls which modulate the flow of brine, in response to process demand.

2.4.3.4

Binary Working Fluid Bypass Control

Before enough working fluid vapor is generated at pressure to start either the feed pump turbine, if used, or the generator turbine, this loop bypasses working fluid vapor to condenser.

The booster pump takes suction off the condensate receiver and by suitable manifolding (bypassing of feed pump) can establish sufficient flow of working fluid, say approximately 10% of design flow, to be able to start the feed pump turbine .

The booster pump can now deliver fluid to the feed pump suction and the feed loop can now be stabilized and gradually brought up to design conditions.

During this period the set point of the PIC bypass control is gradually raised, with an increasing amount of vapor being bypassed to the condenser.

When bypass flow rate equals that required to start the main turbine, vapor can be admitted.

At this time the bypass valve will automatically close.

When turbine generator is on the line and delivering power to the load, the set point of this control is set up slightly higher than that of PRC main pressure control, such that reset (integral) action of controller will drive the PIC control valve completely closed.

If the turbine safety trip valve closes, this control will bypass the flow that was going to turbine and prevent loss of working fluid.

A safety relief valve whose relieving pressure is set at equipment design pressure plus permissible accumulation will back up this control to automatically vent working fluid vapor in the event of controller failure.

2.4.3.5

Safety Trip Devices

Typically both the feed pump turbine and the generator-turbine are equipped with safety trip devices to protect equipment against the following:

Overspeed

Low lube and governor oil pressure

Low seal oil pressure

High bearing or governor oil temperatures

High vibration

High gear oil temperature

In addition the generator is equipped with protective devices such as is described in Section 2.1.2.1 sect. (c)

2.4.3.6

Process Safety Devices

Not shown on cycle flow diagrams but incorporated in a complete design would be such alarms and trip devices as:

Cooling water failure

Instrument air failure

High or low vaporizer level

High knockout pot level (if used)

High and low level in condensate receiver

Low geothermal brine pressure

Control room depressurization

Because of the flammability of the normal binary process fluids such as isobutane, isopentane and various other organic mixtures proposed, a relief header and probably a flare system would be provided to conduct relieved binary fluids or vapors to an area far enough removed from

working areas to not constitute an explosion hazard to personnel or equipment.

Typically, safety relief valves would be provided for the following conditions:

Blocked outlet from process equipment

Fire

Thermal expansion

2.4.4 System Limitations

2.4.4.1 Temperature

In general the binary cycle would be considered for brine temperatures 350°F and below where the excessive amount of brine required to flash an equivalent amount of steam for equivalent generation would be uneconomic.

The lower limit of practical temperature of the working fluid in a binary system would probably be 270°F to avoid an excessive amount of liquid expansion through an expander turbine. The cost of exchangers to obtain a closer approach to the highest brine temperature to minimize the liquid carryover would probably not be

economic. With a direct contact binary cycle the working fluid temperature will approach the brine temperature closer than that which can be achieved with an exchanger type binary cycle. This imposes the constraint of tight temperature control sometimes difficult to attain.

2.4.4.2

Pressure

Brine pressures within the process, at least, should be maintained high enough to preclude flashing in the process train with concomitant fouling and vapor generation. This dictates that pressure drops through the brine loop be maintained as low as possible including pressure drops through control valves. Control valves inherently impose pressure drops in the process piping system and allowance should be made in design to assign a reasonable percentage of total friction drop to control valves. When the pressure base is low, some instability of control may be experienced due to the requirement to limit control valve operating pressure differentials.

Vapor relieving controls must be installed on equipment high points, in brine train to avoid vapor binding of exchangers.

2.4.4.3

Effect of Variable Fouling

It was previously discussed under description of shell and tube binary exchanger cycle, Figure 2.4-2, that the indeterminate deposition of scale and fouling products with time may shift the vaporization of binary working fluid either within a different zone of the vaporizer, or perhaps completely out of that exchanger into a succeeding exchanger downstream. At the extreme, fouling might even not permit the superheater control to function at all. It may call for more brine, but in doing so there is more differential pressure loss in gathering system piping, and brine loop, resulting in an even greater degree of fouling through inability to maintain a high enough pressure to prevent brine from flashing, with consequent greater fouling and less heat transfer.

In any of the cycles considered, fouling not only limits heat transfer but also imposes different process reactions rates. For example, fouling could have the effect of imposing more pressure drop in exchangers and piping and less available drop for brine control valve.

In the temperature control loop inordinately long temperature reaction rate times could lead to instability of temperature control.

Equipment Limitations

Section 1.0 of this source book deals adequately with the limitations of accuracy, repeatability, response, et al of instrumentation devices.

This discussion is limited to instrument environment considerations.

In most processes handling geothermal brine, non-condensable gases contain corrosive elements such as H_2S and even some explosive materials such as methane and hydrogen. H_2S , is perhaps not as significant a problem in binary plants as in flashed steam plants. However it can be expected that some brine leakage will occur, and the binary processes which vent noncondensable gases could conceivably create an H_2S environment which is extremely corrosive to certain materials of construction, even in minute concentrations, particularly copper bearing materials.

Wherever possible, stainless steel should be specified for all control devices in contact with ambient atmosphere or corrosive brine fluids. Where not possible to use stainless steel as for example, in control room

instruments, instruments should be protected by creating a pressurized atmosphere using activated charcoal filtered air.

The proximity to the working fluid which probably would be flammable would similarly require a pressurized control room to exclude potentially explosive gases.

Field instrumentation that cannot be manufactured of stainless steel should be provided in an enclosure that can be purged with dry activated charcoal filtered instrument air, to exclude corrosive or flammable vapors or alternately in an explosion proof enclosure meeting NEMA standards.

2.4.6

Power Plant Transient Behavior

The perturbations that can induce transients into the processes as described, are mainly caused from abrupt generation demand changes, or transmission line or generator faults which would force the plant into the non-lockout operation, as defined in 2.1.2.2, in which the generator turbine continues to run disconnected from outgoing lines.

This mode of operation would tend to lower the demand rate of working fluid vapor to the turbine, by throttling the governor valve to a more closed position. The following effects would occur and the control responses indicated would be required.

- a) Momentarily the speed of the turbine would tend to increase, until the governor throttle valve could correct for overspeed.
- b) The working vapor fluid pressure would tend to increase until the working fluid vapor bypass pressure control starts to open to bypass a large portion of the former turbine flow to the condenser.
- c) Concurrently with b) the brine feed either on pressure or temperature control, would tend to be throttled back as the heat demand is decreased by the reduced turbine load.
- d) The brine bypass valve to injection because of c), under its pressure control system would start to open.
- e) The level control on working fluid vaporizer, where employed, would sense a momentary increase of level

as the demand for vaporized working fluid decreases, and level control would tend to throttle back on the liquid feed to the exchanger train.

- f) The superheater controller where utilized, its set point being unchanged during this upset, would tend to act to maintain the same temperature by either reducing the brine flow as in c), or bypassing more vaporized working vapor around superheater exchanger.
- g) Momentarily because of initial upset, and bypassing of former vapor flow to the turbine through the bypass pressure control valve, the resultant enthalpy of the vapor to condenser would increase (less vapor taking its enthalpy drop through turbine). This might tend to increase the condensing temperature and corresponding saturation pressure. This would be reflected as a higher condenser inlet pressure, and cause PRC control loop to throttle back even more on brine flow through the process.

Because of thermal inertia through exchanger train, binary plants are only to a limited extent adaptable to this type of transient upset. Settle-out time of con-

trols to a markedly reduced load, might be of significant duration. Thus a binary cycle plant is more adaptable to base load operation than peaking or load following.

A more significant transient effect would be a lock-out situation, as described in Section 2.1.2.1.

The most abrupt transient would occur with the closure of the quick-acting turbine trip valve.

The requirements of the pressure indicating control working fluid bypass valve, demands this valve have a speed of response fast enough, on a rapid rise in vapor pressure to prevent relief valves from venting expensive binary fluid. Fortunately, the relieving pressure is probably more than 50% higher than operating pressure, on good plant design, so that in the time of pressure rise from operating conditions to relieving conditions, a pressure corrective action can be obtained with careful selection of this valve and its operator speed.

All other controls would act as previously described.

Normal minor load variations can be adequately controlled with instrumentation shown.