

## Enthalpy and Mass Flowrate Measurements for Two-Phase Geothermal Production by Tracer Dilution Techniques

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### Abstract

A new technique has been developed for the measurement of steam mass flowrate, water mass flowrate and total enthalpy of two-phase fluids produced from geothermal wells. The method involves precisely metered injection of liquid and vapor phase tracers into the two-phase production pipeline and concurrent sampling of each phase downstream of the injection point. Subsequent chemical analysis of the steam and water samples for tracer content enables the calculation of mass flowrate for each phase given the known mass injection rates of tracer. This technique has now been used extensively at the Coso geothermal project, owned and operated by California Energy Company. Initial validation of the method was performed at the Roosevelt Hot Springs geothermal project on wells producing to individual production separators equipped with orifice-plate flowmeters for each phase.

### Introduction

In geothermal fields that produce two-phase fluids, monitoring trends in the enthalpy (heat content) of produced fluids is important for understanding the reservoir's performance. Decreasing enthalpies can indicate breakthrough of injection water or invasion of cooler groundwater. Increasing enthalpies can indicate reservoir boiling and the formation of a steam cap. Enthalpy is essential for the interpretation of geochemical data because it determines the steam fraction at sampling conditions and allows the correction of chemical concentrations back to reservoir conditions. From an operational point of view, the enthalpy and the mass flowrate govern the amount of steam available and ultimately the power output of the plant.

Measuring the total enthalpy of two-phase flow is not a simple process. Defining the pressure and the temperature of the fluids is not sufficient; for a given pressure and temperature, the enthalpy can vary from that of saturated steam to that of saturated liquid, depending on the steam fraction of the mixture. Determining the fraction of vapor ("void fraction") in two-phase flow is a common engineering problem in power generation, oil production and chemical process industries. In a geothermal field, full-flow production

separators can be added to the fluid gathering system to allow measurement of steam and liquid flow independently, but this entails the substantial cost of additional piping and pressure vessels. Chemical methods are available to calculate enthalpy over a broad range of values, but require a significant pressure drop in the two-phase flow line to allow comparison of chemical concentrations at different steam fractions. Geochemically derived reservoir temperatures can be used to estimate total enthalpy, provided the well produces from a single-phase liquid resource.

This paper presents a brief overview of available methods for measuring enthalpy and discusses some of the limitations of each. The paper then describes a new chemical method of enthalpy determination based on the use of tracers in the steam and liquid-phases. The tracer dilution technique was developed specifically for the Coso geothermal field, but is applicable to all two-phase geothermal production. This method does not rely on a pressure drop, but simply on the mixing of tracers in the pipeline between the point of injection and the point of sampling. This technique has been verified by testing in geothermal fields at Coso and at Roosevelt Hot Springs.

### Methods of Enthalpy Determination

Conceptually, the most straightforward way to measure the enthalpy of a two-phase flow stream is to separate the phases and to measure their individual mass flowrates by well-established single-phase measurement techniques, such as orifice plates, Venturi tubes or annubars. Given the mass flowrates of steam ( $Q_v$ ) and liquid ( $Q_L$ ) and the known enthalpies of steam ( $H_v$ ) and liquid ( $H_L$ ) derived from steam tables at the separator pressure, the total enthalpy of the mixture ( $H_T$ ) can be calculated by a simple heat and mass balance equation:

#### Equation 1.

$$H_T = \frac{(Q_v \times H_v) + (Q_L \times H_L)}{(Q_v + Q_L)}$$

Several authors have described the design of separators that can handle the large flowrates typical of geothermal wells. Lazalde-Crabtree (1984) presents a good overview of this subject. For typical geothermal plants requiring

single-phase steam, separators are an integral part of the gathering system. In some geothermal fields, each production well has a dedicated separator. In many cases, however, separators are shared between several wells to minimize capital costs. This results in a loss of the ability to monitor enthalpy trends continuously for individual wells.

Test separators may be installed for groups of wells, so that the flow from individual wells may be diverted and metered separately during test intervals. Alternatively, the flow lines of individual wells may be designed to allow portable test separators to be connected for periodic testing. Steam venting and production loss can be avoided by piping the separated fluids back to the main production line.

Although shared test separators may be less expensive than dedicated separators, they are still costly. In addition to the separator vessels, the capability of flow diversion to a test separator requires extra production piping and valves. Also, diverting the well flow may change the flowing wellhead pressure, which could cause the enthalpy of the fluids produced on tests to differ from the enthalpy under normal operating conditions.

For wells with relatively low flowrates (less than about 15 kg/s), enthalpy can be measured by a total-flow calorimeter. Grant et al., (1982) provide a summary of this technique. James tube testing with a silencer and a weir box can provide reasonably accurate enthalpy values over a wide range of flowrates (James, 1970). Both these methods require diversion of flow from production, with attendant losses of revenue and fluid disposal costs. The atmospheric venting of steam may also require hydrogen sulfide abatement to comply with environmental regulations.

Ultrasonic and neutron-based meters have been developed to determine the mass ratios of steam and liquid in two-phase flow (Shen, 1992; Woiceshyn et al., 1986). However, such devices typically have limitations on the range of steam fractions and pipe diameters with which they can operate. These devices can also lose accuracy due to deposition of scale at the sensor locations.

Flowing pressure and temperature surveys within production wells can be interpreted to estimate enthalpy (Kaspereit, 1990). This technique is useful when fluid enters the wellbore as a single-phase liquid, but it is less reliable when there are fluid entries above the flash point. In addition, access to wells for repeated surveys may be limited by mechanical constraints, such as the presence of tubing for downhole injection of scale inhibitor.

Geothermometry can be used to estimate the enthalpy of produced fluids (Fournier and Potter, 1982). This technique estimates the enthalpy for saturated liquid

based on the corresponding geothermometer reservoir temperature. If some of the fluid enters the wellbore as steam due to boiling within the reservoir, geothermometry will underestimate the enthalpy of fluids produced at the surface.

Other chemical methods to calculate enthalpy involve a comparison of samples collected at two points on the two-phase flow line that differ substantially in pressure. These methods include the gas ratio method (Mahon, 1966) and the chloride method (Marini and Cioni, 1985). Such methods depend on changes in concentration of naturally occurring constituents in the steam or liquid-phases due to flashing between the two sample points. There must be a sufficient pressure drop caused by a flow control valve or other restriction between the sample points to provide a measurable concentration change. If the normal flowing wellhead pressure is close to the gathering system pressure, this technique is not viable. Sufficient pressure drop may be induced by throttling the well, but the total discharge enthalpy may vary with wellhead pressure.

The injection of chemical tracers into two-phase flow allows the determination of individual mass flowrates directly from tracer concentrations and the known injection rates without the requirement of a pressure drop in the flow line. Liquid-phase tracers have been used extensively in surface and groundwater hydrology to estimate the flowrates of water, and to a limited extent in geothermal fields to determine mass flowrates of produced and injected liquid (Ferrer, 1992). The mass flowrates of liquid streams, liquid fractions and steam quality involved in geothermal fluid treatment processes such as H<sub>2</sub>S abatement and HCl corrosion mitigation have been routinely determined using sodium ion as the tracer (Hirtz and MacPhee, 1989; Hirtz et al., 1991). Steam flowrates venting from geothermal drilling mufflers at The Geysers are routinely estimated from air to steam ratio measurements of samples collected during air-drilling operations. The current work applies similar principles to determine steam and liquid-phase flowrates simultaneously in a two-phase flow stream and uses the ratio of steam and liquid mass rates to determine the total fluid enthalpy.

## **Tracer Dilution Testing Technique**

### *Theory of Method*

The tracer dilution enthalpy measurement technique requires precisely measured rates of vapor and liquid-phase tracers injected into the two-phase flow stream. Samples of each phase are collected from sampling separators downstream of the injection point, before injection for background analysis, and concurrent with tracer injection. Chemical analysis of the vapor and liquid-phase samples for tracer content is performed, and the mass flowrate of each phase is calculated based on

these measured concentrations and the injection rate of each tracer.

The liquid-phase mass rate is given by:

**Equation 2.** 
$$Q_L = \frac{Q_T}{(C_{TL} - C_{BL})}$$

$Q_L$  = Liquid-phase Mass Rate  
 $Q_T$  = Tracer Injection Mass Rate  
 $C_{TL}$  = Liquid-phase Tracer Concentration by Weight  
 $C_{BL}$  = Liquid-phase Background Concentration by Weight

The vapor-phase mass rate is given by:

**Equation 3.** 
$$Q_V = \frac{Q_T}{(C_{TV} - C_{BV})}$$

$Q_V$  = Vapor-phase Mass Rate  
 $Q_T$  = Tracer Injection Mass Rate  
 $C_{TV}$  = Vapor-phase Tracer Concentration by Weight  
 $C_{BV}$  = Vapor-phase Background Concentration by Weight

The mass rates calculated are valid for the temperature and pressure at the sample collection point. The total fluid enthalpy can then be calculated using the same heat and mass balance equation as shown above for the total fluid enthalpy calculation of separated steam and water (Equation 1).

### Tracer Selection Criteria

The selection of liquid and vapor-phase tracers for the tracer dilution technique was based on an evaluation that included the following considerations:

- Each tracer must partition completely into their respective vapor or liquid-phase.
- The tracers must be thermally and chemically stable under the conditions of two-phase geothermal production.
- The liquid-tracer must be highly soluble in water and the gas-tracer must have a high vapor pressure to facilitate injection and metering.
- Quantitative, highly precise analytical methods with wide linear ranges must be available to measure the tracers in a geothermal fluid matrix.
- The natural background levels of the tracers must be fairly low and constant.
- The cost of the tracers must be reasonable for the quantities to be injected given the background levels.

Several inorganic ions were considered for use in the Coso geothermal field as the liquid-phase tracer. These included fluoride (as KF), bromide (as NaBr), lithium (as LiCl), cesium (as  $Cs_2SO_4$ ), and magnesium (as  $MgCl_2$ ). Organic tracers such as fluorescein dye, rhodamine WT dye, benzoic acid and benzene sulfonates were not considered for this application since these compounds are used in reservoir injection tracer studies and routine use for enthalpy testing would contaminate the reservoir and preclude their primary use (Adams et al., 1992). There is also less certainty that the organic tracers could be used in applications requiring highly quantitative recoveries and analytical detection.

All of the inorganic tracers listed above will partition completely into the liquid-phase at normal two-phase geothermal production temperatures. The inorganic tracers are also thermally stable, but fluoride and magnesium may precipitate under certain conditions. Fluoride can precipitate as fluorite ( $CaF_2$ ) at reservoir temperatures if sufficient concentrations of calcium and fluoride ions are present. Fluorite is usually undersaturated by one order of magnitude in Coso reservoir fluids. Magnesium can precipitate as magnesite ( $MgCO_3$ ) if sufficient concentrations of magnesium and carbonate ions are present, or co-precipitate in calcite ( $(Ca,Mg)CO_3$ ). Since calcite deposition is a problem for many wells at Coso, a magnesium tracer does not seem to be a prudent choice for flashed liquid already supersaturated in calcium carbonate.

The inorganic tracers considered for use are highly soluble, except for lithium. Due to the low molecular weight of lithium, a maximum solution concentration of only 5 weight % lithium ion can be made from the lithium chloride salt. The highest tracer concentrations can be achieved for bromide and cesium, both at 30 weight % for the respective anion and cation. Low tracer solubility will cause logistical problems during enthalpy tracer testing in the areas of chemical mixing, storage, transport and injection, especially if the background levels of the tracer are high, requiring greater quantities of tracer for injection.

The inorganic tracers listed above are readily detected with modern analytical instrumentation. The anions, fluoride and bromide, can be analyzed precisely by ion-chromatography (IC). The geothermal brine matrix required the development of specific IC methods by Thermochem laboratories for accurate detection of fluoride and bromide in the presence of high chloride concentrations. The cations, lithium, cesium and magnesium can be analyzed precisely by atomic absorption spectrophotometry (AAS) or inductively-coupled plasma emission spectroscopy (ICP). However, the IC methods for the anion tracers are more precise and have a greater linear range than the AAS or ICP methods for the cations.

The background levels of the inorganic tracers range from less than 0.02 ppm<sub>w</sub> for magnesium to about 15 ppm<sub>w</sub> for lithium in the geothermal liquid produced at Coso. In order to maintain a high degree of accuracy and minimize the effects of background concentrations on the tracer dilution technique, a tracer concentration of at least 10 times the background level is desired during the test. The background levels for all the potential inorganic tracers at Coso are not a problem, with the exception of lithium which has the highest background and lowest solubility, requiring unreasonably high tracer solution injection rates.

The chemical cost per hour of injection, which is the typical duration of an enthalpy tracer test, ranges from \$33.00 for magnesium (at 100 times the detection limit) to \$1,420.00 for lithium (at 10 times background), given a 50 kg/s liquid flowrate with the average background levels found at Coso.

Based on the criteria outlined above, fluoride was chosen as the initial liquid-phase tracer to be tested at Coso and Roosevelt Hot Springs. Bromide was not tested initially due to analytical problems in the IC procedure caused by the high chloride content of the samples. The analytical procedure was later developed for high-precision bromide analysis by IC, with comparable accuracy and precision to the fluoride procedure.

The gases considered for use in Coso as vapor-phase tracers were ethane, propane, butane and helium. Unsaturated hydrocarbons such as ethene and propene were not considered due to potential chemical and thermal instability. These compounds are also easily hydrolyzed by caustic which is commonly used in geothermal gas collection bottles to absorb CO<sub>2</sub>. Sulfur hexafluoride and the halocarbons were not considered for routine use because they are used in reservoir injection tracer studies and this application would contaminate the reservoir (Adams et al., 1991).

Each of these potential vapor-tracers will partition completely into the steam phase with minimal solubility in the liquid at production temperatures. There are also no known chemical or thermal instability problems associated with their use under surface production conditions.

The vapor pressure of the gas tracers is an important parameter in tracer selection. The injection of gas tracers is easiest if the tracer can be maintained as a gas during metering and injection. Since the hydrocarbons considered have relatively low vapor pressures, they must be obtained as gas mixtures, diluted with nitrogen or helium in high-pressure cylinders (140 bar). The vapor pressure limits the maximum tracer concentration possible in these cylinders: ethane mixtures can be as high as 17% by volume and propane up to 2.9%, but butane mixtures are limited to only 0.68% by volume. Pure

gases could also be injected from liquefied gas cylinders, but the cylinders would have to be heated to maintain sufficient pressure during injection.

The hydrocarbon gas tracers can be analyzed by gas chromatography with flame ionization detection (GC/FID). This method is highly precise and has a linear range of several orders of magnitude. Trace background levels of hydrocarbons can be easily detected in geothermal steam at low part-per-billion concentrations. Helium can be analyzed by gas chromatography with thermal conductivity detection (GC/TCD). Background levels of helium in the part-per-billion by weight range can also be detected with the proper instrumentation, although the linear range is not as broad.

The background levels of vapor-phase tracers are significantly more variable than the liquid-phase tracer concentrations and make it necessary to inject the gas tracers at about 100 times the average background value. Given this requirement and the maximum volume % of tracer possible in high-pressure cylinders, ethane and butane must be injected at rates that are impractical for routine application at Coso. Due to the low molecular weight of helium, the pure gas injection rate from a high-pressure cylinder is also too high for routine use. Propane mixtures can be injected at rates of 1/4 to 1/10 that of the other gas tracers, given the average background propane level at Coso, about 0.010 ppm<sub>w</sub>. Due to the logistical simplifications in handling the smaller quantities of propane required for injection, propane was chosen as the vapor-phase tracer for enthalpy tracer testing at Coso.

The costs of the vapor-phase tracers are relatively low, ranging from \$24.00 to \$107.00 per hour to measure a 12.5 kg/s steam flowrate at Coso, given average background levels.

#### **Tracer Metering Techniques**

The tracer dilution enthalpy technique relies upon accurate and precise metering of the liquid and vapor-phase tracers injected into the two-phase flow stream. Mass flowrate measurement devices were initially chosen as the best means to meter the tracers without errors related to gas and liquid density and viscosity corrections over the wide range of operating temperatures required. Constant injection rates are also necessary to minimize errors and data reduction complications associated with the time delay between injection of tracer and subsequent recovery by sampling downstream.

The liquid-tracer delivery methods evaluated were pressurized reservoir systems, rotary gear pumps and positive displacement metering pumps. Pressurized reservoirs could be designed to deliver tracer at any pressure required, but it is difficult to reproducibly control the injection rate which depends upon the pressure drop across a small orifice, capillary tube or

metering valve. Pressure surges in the two-phase flow line, which are common in geothermal production, will also affect the output rate of these systems. Another consideration is that the system would have to be shut down to replenish the reservoir. Unfortunately, variable-speed rotary gear pumps, which do not suffer from these problems, could not be obtained for the flowrate and discharge pressures required. This left positive displacement metering pumps which typically do not deliver a continuous flow stream, but pulsations that could result in periodic concentration spikes of tracer in the liquid-phase. The liquid delivery system finally selected for testing of the enthalpy tracer method was a positive displacement metering pump, relatively insensitive to discharge pressure fluctuations, operating at a high stroke frequency in conjunction with a pulsation damper to effectively produce a continuous flow stream.

The true mass injection rate of the liquid-tracer is monitored by an electronic balance (50 g resolution, 150 kg capacity) interfaced to a portable computer. The metering pump draws from a 60 liter reservoir placed on the balance, which measures the weight loss continuously during injection. The computer records the weight loss data versus time and calculates the mass injection rate over selected intervals, in addition to running averages and cumulative totals. Although the stroke setting of the metering pump provides reproducible injection rates, monitoring true mass delivery results in the highest possible accuracy.

A mass flow-based system was also selected for gas tracer delivery. The gas tracer is metered directly from a gas pressure regulator manifold connected to the high pressure gas mixture cylinders. An electronic mass flow controller regulates the gas flowrate with high precision by sensing the cooling of an integral heated coil exposed to the flowing gas. This cooling effect is proportional to the mass flowrate of the gas. A solenoid metering valve is continuously adjusted by the control unit to maintain the gas flow at the desired set-point. This is a standard laboratory and industrial device for high-accuracy gas metering, with certain modifications to accommodate the relatively high delivery pressure requirements. A back-pressure regulator was also added to the system to eliminate rapid cycling of the controller caused by pressure surges in the two-phase line.

The liquid and gas tracers are co-injected through a stainless-steel probe inserted into the two-phase flow line near the wellhead. A probe is used to eliminate any possible leakage of tracer from the sample port valve packing or related connections, and to deliver the tracers directly into the flow stream. The tracer injection hoses and probe connections are easily leak-checked during testing. A tracer leak would obviously induce an error in the actual amount of tracer injected into the flow stream, resulting in erroneous flowrate and enthalpy measurements.

### ***Tracer Sample Collection Techniques***

Samples of the steam and liquid-phases are collected downstream of the tracer injection point, which is near the wellhead, according to standard two-phase geothermal fluid sampling methods (ASTM E-44). In order to obtain representative samples of each phase, the sampling separator used to collect steam samples is attached to the top of the horizontal two-phase flow line and the liquid separator is attached to the bottom of the line. Since the fluid in most two-phase geothermal production lines is nearly stratified, this configuration usually insures that sufficient quantities of each phase are available to the separators, where a final high-quality separation is achieved.

The sample points at Coso are normally located downstream of the flow control valve(s) for the well tested, and as far downstream of the injection point as possible. The flow control valve provides agitation in a similar manner to a Venturi mixer, effectively distributing the tracers within each phase. The shortest lengths between injection and sampling points at Coso are restricted to 18 meters by the existing gathering system configuration.

The liquid samples are cooled through a sample condenser and collected over a time interval of at least 2 minutes to integrate any short-term fluctuations in tracer concentrations. The samples are stored in plastic bottles without further treatment before analysis. The steam samples are passed through a condenser and the condensate plus noncondensable gases are collected in evacuated glass bottles containing sodium hydroxide. The caustic solution absorbs CO<sub>2</sub>, the predominant noncondensable gas, and enables a sufficient quantity of condensate to be collected in the bottle with the gases, resulting in a representative sample of condensed steam and tracer gas. These bottles are filled over a 3 to 5 minute interval, which also helps integrate any short-term tracer fluctuations due to flow surging of the wells. Several liquid and steam samples are collected during the length of the test.

### **Field Testing**

Comparative field tests of the tracer dilution technique to other enthalpy measurement methods were initially conducted at the Coso geothermal field in California and at the Roosevelt Hot Springs geothermal field in Utah. At Coso, separators in the gathering system are typically shared by several production wells, and the tracer dilution tests on individual wells were compared to James tube tests. At Roosevelt, dedicated production separators allowed verification of tracer dilution tests with reference to orifice meter measurements of separated steam and liquid.

## Coso

The Coso Geothermal Field produces two-phase fluids from fractured, crystalline rock at depths ranging from approximately 400 to 3,200 meters. Reservoir temperatures range from approximately 200 to 345°C. Commercial production began in July 1987 with a 30 MW, dual-flash power plant. By the end of 1989, plant capacity had expanded to a total of 240 MW from nine turbines at four plant sites. As of December 1, 1992, 68 production wells were in active use. The reservoir was initially liquid-dominated, with a pre-existing steam cap that has expanded with exploitation. The total mass flowrates of individual wells range up to about 125 kg/s and are generally in the range of 10 to 100 kg/s. The enthalpies of produced fluids at the wellhead range from 840 to 2,800 kJ/kg.

Initial tests on Coso wells in the early 1980's used test separators to establish flowrates and enthalpy values. The testing procedure was later simplified so that most of the initial tests at Coso were performed using just James tubes, silencers, and weir boxes. When gathering systems were designed for the first few plants, it was intended to use the gas ratio method to monitor enthalpy trends for wells in production. This technique was successful when the wells first went on line, because wellhead pressures were high enough to allow substantial pressure drops in the flow lines between sampling points.

Within a year of start-up, however, declines in wellhead pressure (often aggravated by wellbore scaling) caused a loss of resolution in the gas ratio measurements, and the enthalpy values from these measurements became unreliable. James tubes and weir boxes were added as permanent components of the gathering system, and a program of quarterly testing of all production wells was implemented in the summer of 1991. This improved the quality of enthalpy determinations, but taking wells off-line for James tube testing decreased the power output of the plants and upset the balance of the other wells in the gathering system. Also, some wells could not be vented to atmosphere at full flowrates without exceeding environmental limits on H<sub>2</sub>S emissions. Tracer dilution testing was undertaken in the winter of 1991-92 to establish a reliable means of determining enthalpies without taking wells off-line.

## Comparative Test Results for Coso

Propane and potassium fluoride tracers were injected into the two-phase flow lines of three wells at Coso according to the procedures described above. One well produced fairly low enthalpy fluids (900-950 kJ/kg) and the other two produced higher enthalpy fluids in the 1400 to 1900 kJ/kg range. The tests were conducted over intervals of 2 to 3 hours to document the ability of each method to track short term trends in flowrate and enthalpy. The wells were diverted from plant production to the James tube and silencer/weir box facility located on each wellpad and allowed to stabilize before starting the comparative tests. In at least one case the wellhead pressure varied sufficiently after flow diversion to cause a substantial change in the normal discharge characteristics of the well. The wellhead pressure, James tube lip pressure and weir box liquid level were recorded every 10 to 15 minutes during the tests. The distributed computer control system (DCS) for the well field also recorded the upstream orifice pressure, temperature and the differential orifice pressure from the two-phase flow line continuously.

Table 1.0 summarizes the results of these initial tests at Coso. The total flowrate and enthalpy measurements for the lower enthalpy well agreed within 1.4% and 3.7%, respectively. This well produced a fairly high liquid rate of 34 kg/s with minimal flow surging during the test. The differences in total flowrate for the higher enthalpy wells were 5.5% to 25% and the enthalpy differences were 12% to 14%. These wells produced low liquid rates, 8.5 to 15 kg/s, and the discharge from well C-3 surged at regular intervals during the test, with liquid rate variations of  $\pm 50\%$ .

The flowrate, enthalpy and differential pressure trends obtained from the C-3 well test are plotted in Diagram 1.0. As shown, variations in total flowrate correlate between the tracer and James tube techniques, and rate peaks correspond to orifice plate differential pressure spikes. A slight delay in the maximums is indicated for the James tube rates relative to the tracer rates. The James tube and weir box are at the very end of the two-phase flow line, while the tracer measurements represent flow conditions within approximately the mid-section of the line. The James tube results do not exhibit the same

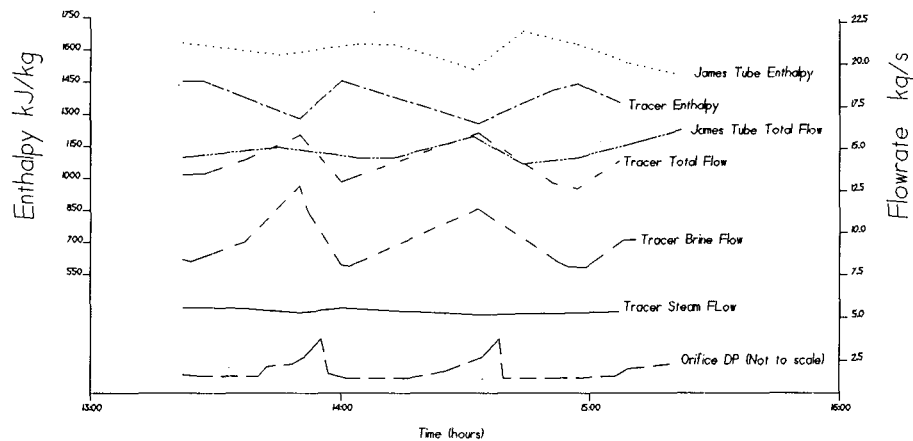
Table 1.0 COSO TRACER DILUTION TEST SUMMARY

### Comparison of Tracer Results to James Tube Measurements

Well Name	TOTAL FLOWRATE, kg/s			TOTAL ENTHALPY, kJ/kg			COMMENTS
	James Tube	Tracer Test	$\Delta$ %	James Tube	Tracer Test	$\Delta$ %	
C-1	36.9	37.4	1.4	949	914	-3.7	High Liquid Rate, Stable Flowrates
C-2	20.9	26.8	25	1870	1630	-14	Low Liquid Rate, Variable Lip Pressure
C-3	14.1	13.4	-5.5	1588	1402	-12	Low Liquid Rate, Low Lip Pressure, Flow Surging

Diagram 1

### Well C-3 Enthalpy and Flowrate Trends



amplitude of variation as the tracer results, which is most likely due to the buffering effect of the large cyclone silencer that drains to the weir box.

The differences between the two methods observed for the low liquid rate wells do not appear to be the result of any systematic error in the tracer technique. Tracer injection rates were varied by up to 100% during these tests, producing consistent flowrate and enthalpy values in the final calculations, which demonstrates a lack of dependence on tracer to liquid or steam ratios. Sampling bias due to low liquid rates was also eliminated as a possible cause; well C-3 liquid was collected from a sampling separator, but the other high enthalpy well (C-2) was sampled directly from the weir box due to a lack of sample ports. Adequate mixing of tracers in the two-phase flow stream was insured by the exceptionally long mixing runs between tracer injection and sample collection points for the low liquid rate wells tested (84 to 90 meters).

However, the James tube results rely on weir box liquid levels for the liquid flowrate measurement, which can easily be in error by up to  $\pm 20\%$  due to flow surges, scale reading error, and errors in the zero value for the level. These errors are accentuated by low liquid flowrates. Other problems noted for the low liquid rate wells were variable lip pressures for C-2 and low lip pressure readings for C-3.

The results of the initial enthalpy tracer tests were encouraging enough to warrant additional testing against an enthalpy and flowrate standard more reliable than the James tube method, such as the individual production separators and orifice meters in use at the Roosevelt Hot Springs geothermal field. This comparison is described in the following section.

#### Roosevelt Hot Springs

The geothermal field at Roosevelt Hot Springs is similar to Coso in that it produces two-phase fluids from fractured, crystalline rock. Productive depths range from about 500 to 1,650 meters, and reservoir temperatures are in the range of 230 to 260°C. Commercial production began in 1984. Currently, four production wells supply steam to a single-flash 25 MW power plant. Flowrates per well are in the range of 75 to 125 kg/s, with enthalpies of approximately 1,070 kJ/kg. The production wells were drilled with a spacing of roughly 400 meters. Because of the distance between the wells, the gathering system was constructed with dedicated separators for each well. This afforded an opportunity to test the tracer dilution technique on individual wells with reference to single-phase measurements downstream of the separators.

#### Comparative Test Results for Roosevelt

Tracer enthalpy testing was conducted at the Roosevelt geothermal field in April 1992, during normal production of the three wells in service. Propane and potassium fluoride tracers were also used for these tests, but a higher capacity metering pump and gas mass flow controller were required to inject sufficient tracer into the generally larger production wells at Roosevelt. The tracers were injected over 2 to 4 hour periods while samples were collected from sampling separators upstream of the production separators, and downstream of the separators from the single phase liquid and steam lines. Production separator pressures, liquid levels and orifice plate differential pressures for steam and liquid were recorded both manually at 20 minute intervals and continuously by the DCS. Minimal flow surging was experienced during these tests.

Table 2.0 ROOSEVELT TRACER DILUTION TEST SUMMARY

PRODUCTION SEPARATOR TRACER RESULTS VERSUS ORIFICE MEASUREMENTS

Well Name	STEAM FLOWRATE, kg/s			LIQUID FLOWRATE, kg/s			TOTAL ENTHALPY, kJ/kg		
	Orifice	Tracer	Δ%	Orifice	Tracer	Δ%	Orifice	Tracer	Δ%
R-1	20.2	20.8	3.08	103	103	0.12	1072	1079	0.65
R-2	18.1	17.8	-2.11	94.3	98.0	3.80	1065	1049	-1.54
R-3	11.8	11.6	-1.93	61.5	60.8	-1.03	1065	1063	-0.22

SAMPLING SEPARATOR TRACER RESULTS VERSUS ORIFICE MEASUREMENTS

Well Name	STEAM FLOWRATE, kg/s			LIQUID FLOWRATE, kg/s		
	Orifice	Tracer	Δ%	Orifice	Tracer	Δ%
R-1	20.2	(1)	-	103	105	2.17%
R-2	18.1	(1)	-	94.3	97.6	3.41%
R-3	11.8	13.2 <sup>(2)</sup>	11%	61.5	149 <sup>(2)</sup>	83%

- (1) Adequate steam samples could not be obtained due to improper sample port orientation.
- (2) Incomplete mixing of tracer due to short section of pipe between injection and sampling point: 7 meters

Table 2.0 summarizes the Roosevelt comparative test results for steam flowrate, liquid flowrate and total enthalpy. As shown in the comparison of tracer results for samples collected downstream of the production separator, the greatest deviation for any of these parameters was a 3.8% difference in liquid flowrate for well R-2. Sampling upstream of the production separator from the two-phase line was limited by the availability of sample ports in the proper locations and orientations. Adequate steam samples could not be obtained from the two-phase lines of wells R-1 and R-2, which lacked top sample ports for the steam separator. The liquid samples collected from the two-phase lines of these wells generated liquid rate results within 3.4% of the orifice meter values.

The two-phase line for well R-3 was only 7 meters long between the tracer injection point and two-phase sample point, while the mixing runs for wells R-1 and R-2 were 140 to 150 meters long. For this reason, the liquid-phase tracer obviously had not mixed sufficiently, producing an 83% deviation in the sampling separator results for the liquid flowrate of well R-3. However, the steam rate was only in error by 11% given the same mixing run length. The steam phase is fully developed turbulent flow, dispersing the vapor-phase tracer much faster than the liquid-phase tracer which is constrained by the slug flow regime that exists in the two-phase lines of these wells.

Based on the excellent agreement generally observed between the tracer dilution and orifice meter flowrate and enthalpy determinations, tracer dilution was considered a valid measurement technique to be applied routinely at the Coso geothermal field, as well as other geothermal fields where needed.

*Fieldwide Enthalpy Testing at Coso*

In order to implement the tracer dilution technique on a fieldwide basis at Coso, approximately 120 sample and tracer injection ports had to be installed on two-phase

lines throughout the well field. It was determined that port and valve installation by the hot-tap process was less expensive and more expedient than taking wells off-line and isolating the flow lines for the installation procedure. A tracer injection trailer unit outfitted with metering pumps, electronic balance, computer, gas mass-flow controller, generator, gas cylinder racks, and a 750 liter storage tank was fabricated by Thermochem for this application. Tracer storage facilities and chemical mixing equipment to prepare the liquid-phase tracer are also maintained on-site at Coso.

A total of 75 enthalpy tracer tests have been performed to date in Coso on wells ranging in enthalpy from 840 to 2760 kJ/kg. The first fieldwide test was performed with potassium fluoride as the liquid-tracer. Sodium bromide was later substituted for potassium fluoride after fluorite precipitation was observed during tracer tests conducted in wellbores at reservoir temperatures. During these tests, tracer was injected through the downhole scale inhibitor tubing of some wells at Coso to test for inhibitor recovery back up the wellbore, in an effort to optimize the tube setting depth (Lovekin, 1990). The fluoride loss was detected by comparing the recovery of fluoride ion to potassium ion during the down-hole tests where potassium fluoride tracer was injected. Similar comparisons performed for surface enthalpy tests did not indicate any significant loss of fluoride. In order to eliminate any potential for precipitation during downhole recovery or surface enthalpy tests, sodium bromide is now used as the routine liquid-phase tracer at Coso.

The results of the fieldwide enthalpy tests are generally consistent with the historical James tube results for the wells at Coso. However, many wells had not been tested by the James tube method for six months or more, making it difficult to compare results directly in a field where enthalpies can change over short time spans due to processes such as reservoir boiling, wellbore scaling and injection breakthrough. The enthalpy tracer results have



**Table 3.0 REPEATABILITY OF TRACER DILUTION ENTHALPY MEASUREMENTS**

Well Name	Test Date	Liquid Phase Tracer	Total Enthalpy, kJ/kg	% RSD
C-5	10/20/92	Fluoride	1267	0.6
	11/08/92	Fluoride	1256	
C-9	10/23/92	Fluoride	2349	1.6
	12/18/92	Bromide	2404	
C-10	10/06/92	Fluoride	988	1.5
	10/06/92	Potassium	1011	
	11/07/92	Bromide	1017	

been internally consistent and repeatable. This is demonstrated by the results summarized in Table 3.0 for all repeat tests performed on wells not known to be subject to any of the processes described above that would change the enthalpy between tests. These repeatability results are also based on various liquid-phase tracers: fluoride, bromide and potassium.

Tracer mixing efficiency studies have also been performed during enthalpy testing at Coso. The degree of uniform tracer dispersion within the liquid-phase can be evaluated by collecting liquid samples from sampling separators attached to both the bottom and top ports of the two-phase flow line. Since the bulk of the liquid-phase flows along the bottom of the pipeline, uniform dispersion can be assumed if equivalent tracer concentrations are obtained from the top of the pipeline where liquid is present as the upper crests of wave and slug flow or as annular films. Table 4.0 lists the results of these tests by comparing the liquid-tracer concentrations and derived liquid flowrates for liquid samples collected simultaneously from the bottom and top ports.

In the first case shown in Table 4.0 for well C-4, two sets of bottom and top samples were collected from different points along the pipeline. Upstream of the control valve, after a 38 meter mixing run, the first set shows the greatest difference, 9.4% between flowrates calculated

from bottom and top samples. Downstream of the control valve, 58 meters downstream of injection, the bottom versus top derived flowrates differ by only 3.3%. All other tests were conducted on wells with very short mixing runs, 18 to 22 meters long, where the sample ports are downstream of the flow control valve. The greatest deviations are for wells producing high liquid rates (>35 kg/s), with a maximum difference between top and bottom ports of 5.4% for well C-6. This well produces fluid at significantly higher velocities and under a more turbulent two-phase flow regime than well C-5. However, C-5 exhibits essentially perfect mixing, and only produces about 1/5 the liquid of C-6 under a nearly stratified two-phase flow regime. The degree of tracer dispersion within the liquid-phase appears to be more dependent on the total liquid mass than the velocity and the two-phase flow regime under the conditions encountered. Still, sampling downstream of the flow control valve, as is routinely done, seems to provide adequate mixing of the liquid-phase tracer.

Additional mixing data for well C-5 is given in Table 5.0 as a function of mixing run length. The liquid rate derived from samples collected upstream of the flow control valve and only 12 meters downstream of injection is within 1.8% of the rate calculated for the normal downstream sample port. The furthest upstream port, only 3 meters after injection, produced a liquid rate value

**Table 4.0 LIQUID PHASE TRACER MIXING EVALUATION**

**Bottom versus Top Sample Ports**

Well Name	BOTTOM PORT	TOP PORT	Δ %	Mixing Run, m	Two-Phase Flow Regime
	Liquid, kg/s	Liquid, kg/s			
C-4	58.6	64.4	9.43	38	Slug Flow
C-4	60.5	62.5	3.28	58 <sup>(1)</sup>	Slug Flow
C-5	11.3	11.4	0.89	18 <sup>(1)</sup>	Wave to Slug Flow
C-6	52.8	50.0	-5.39	18 <sup>(1)</sup>	Slug to Annular Flow
C-7	7.85	7.71	-1.78	18 <sup>(1)</sup>	Annular to Annular Mist Flow
C-8	35.9	37.7	4.79	22 <sup>(1)</sup>	Slug Flow

(1) Flow control valve upstream of sample point

Table 5.0

## TRACER MIXING EVALUATION

WELL C-5

Sample Port Location	Mixing Run, m	LIQUID PHASE		$\Delta\%$ <sup>(1)</sup>	STEAM PHASE		$\Delta\%$ <sup>(1)</sup>
		Tracer ppm <sub>w</sub>	Flow, kg/s		Tracer ppm <sub>w</sub>	Flow, kg/s	
Downstream	18 <sup>(2)</sup>	129	11.3	0	1.20	3.89	0
Midstream	12	131	11.1	-1.8	(3)	(3)	-
Upstream	3	228	6.29	-44	1.37	3.40	-13

- (1) Percent difference relative to downstream port  
 (2) Flow control valve upstream of sample point  
 (3) No midstream port available for steam samples

differing by 44% from the downstream rate. Steam samples also collected 3 meters after injection were in error by only 13%, demonstrating the rapid dispersion of gas-tracer in the vapor-phase.

A statistical error analysis for the tracer dilution technique was performed based on the known limits of error for the tracer injection rate, the analytical error which incorporates any error associated with the tracer concentration, and estimated errors attributed to tracer mixing and sample collection. The tracer injection rates are determined by instruments that are regularly calibrated against primary standards traceable to the National Bureau of Standards (NBS). The sampling and mixing errors are estimated from the mixing analyses discussed above and comparisons of samples collected from sampling separators versus full production separators during chemical testing performed by Thermochem in several geothermal fields. The sampling and mixing errors probably represent worst case values, since the mixing analyses include sampling error associated with liquid sample collection from the top pipeline ports, where representative liquid samples can be difficult to collect. The analytical error includes any uncertainty in tracer concentrations: the gas-tracer is actually used as the analytical standard for gas samples, and the liquid-tracer concentration is determined relative to the same standards and procedures as liquid samples.

This analysis yields a cumulative error limit of 4.3% for steam flowrate, 6.5% for liquid flowrate, and 3.4% for total enthalpy, as summarized in Table 6.0.

## Further Work

Additional work will be performed in determining the minimum pipeline configuration requirements for tracer dispersion under various flow conditions. Correlation of tracer-based flowrate measurements to differential pressure data from orifice meters in two-phase service can now be performed extensively at Coso to improve the accuracy of two-phase orifice meters in measuring total flowrates of known enthalpy. Development of real-time tracer measurement systems would also be useful in applications requiring continuous enthalpy and flowrate determinations.

## Conclusions

Based on the comparative enthalpy testing in Roosevelt and the fieldwide testing performed in Coso, the tracer dilution technique is considered an accurate and cost effective well testing procedure for both the discharge rate of steam and liquid and the total enthalpy of two-phase flow. This technique eliminates the need for dedicated production separators for each well in new geothermal fluid gathering systems and the installation of test separators to existing systems. The tracer dilution

Table 6.0

## TRACER DILUTION TECHNIQUE ERROR ANALYSIS

STEAM PHASE						Cumulative Error Steam Flowrate
Gas Tracer Concentration	Calibration	Gas Tracer Injection Rate	Calibration	Sampling and Mixing Error	Analytical Error	
±2.0%	NBS Traceable Gravimetric	±1.5%	NBS Traceable Liquid Film Flowmeter	±2.0%	±2.0%	±4.3%

LIQUID PHASE						Cumulative Error Liquid Flowrate
Liquid Tracer Concentration	Calibration	Liquid Tracer Injection Rate	Calibration	Sampling and Mixing Error	Analytical Error	
±1.0%	NBS Traceable Gravimetric	±0.5%	NBS Traceable Weight Standards	±5.0%	±1.0%	±6.7%

Cumulative Error Total Enthalpy	±3.4%
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method is also applicable to short term well tests in new geothermal fields, precluding the need for fabrication of large test mufflers for liquid separation and measurement. This method may be employed to calibrate existing and/or experimental single and dual-phase flow measurement devices.

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