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TRACER DILUTION MEASUREMENTS FOR TWO-PHASE GEOTHERMAL PRODUCTION: COMPARATIVE TESTING AND OPERATING EXPERIENCE

Paul Hirtz(1) **and Jim Lovekin**(2).

(1)**Thermochem, Inc. Santa Rosa, CA**
(2)**California Energy Company, Ridgecrest, CA**

Abstract

The tracer dilution technique for the measurement of steam and water mass flowrates and total enthalpy of two-phase geothermal fluids has been in routine use in the U.S.A. for almost three years. The tracer technique was first tested and adopted on a field-wide basis at the Coso geothermal field in California. Validation of the method was performed at the Roosevelt Hot Springs geothermal project in Utah and the Salton Sea and Heber geothermal projects in California by direct comparison to orifice-plate flowmeter measurements of the separated phases. Production well mass flowrates and total enthalpy are now regularly measured by this technique in the Coso, Salton Sea and Heber geothermal fields. Implementation of the tracer method is currently underway for the Tiwi and Bulalo geothermal fields in the Philippines. This paper presents the conceptual design of the measurement process, the results of field validations. and operating experience during field-wide testing in Coso.

I. 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. The enthalpy and mass flowrate govern the amount of steam available from each well and ultimately the energy output of the power plant.

The mass flowrate of each phase and the corresponding total enthalpy can be measured directly for individual geothermal wells that produce to dedicated separators. However, due to the high capital cost of production separators, most geothermal fluid gathering systems are designed with satellite separation stations in which several wells produce to a single separator. In many cases all of the two-phase fluids produced from a field are combined by the gathering system and separated in a large vessel at the power plant. Without dedicated production separators for each well, the steam and water mass flowrates and the total enthalpy of individual wells cannot be monitored during normal production.

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. Steam venting and production loss can be avoided by piping the separated fluids back to the main production line. However, diverting the well flow may change the flowing wellhead pressure, which could cause the enthalpy and flowrate of the fluids produced during tests to differ from the enthalpy and flowrate under normal operating conditions. Although lower in cost than dedicated production separators, test separator facilities still have relatively high capital and operating costs.

James tube testing with a silencer and a weir box can provide reasonably accurate enthalpy and mass flowrate values (James, 1970). This method requires diversion of flow from production, with attendant revenue losses and fluid disposal costs. The atmospheric venting of steam may also require abatement of hydrogen sulfide to comply with environmental regulations.

Flowing pressure and temperature (P-T) surveys within production wells can be interpreted to estimate enthalpy (Kaspereit, 1990). This method is accurate when the fluid enters the wellbore as a single-phase liquid, but it is much less reliable when there are fluid entries above the flash point. The interpretation of flowing P-T surveys gives only qualitative information about mass flow rates. Geothermometry can be used to estimate the enthalpy of produced fluids (Fournier and Potter, 1982). However, this technique also requires the fluid to enter the wellbore as a single-phase liquid and it provides no information about the mass output of the well.

The injection of chemical tracers into two-phase flow allows the determination of steam and water mass flowrates directly from tracer concentrations and the known tracer injection rates without disrupting the normal production conditions of the well. This testing technique does not require any flow diversion from the power plant, so there are no power revenue losses or environmental impacts due to discharged steam and water.

II. Tracer Dilution Technique

Theory of Method

The tracer dilution technique requires precisely metered rates of liquid- and vapor-phase tracers injected into the two-phase flow stream. Samples of each phase are collected from sampling separators at a location far enough downstream of the injection point to insure complete mixing of the liquid and vapor tracers in their respective phases. Samples are collected both before tracer injection (for background analysis) and again during tracer injection. The water and steam samples are analyzed for tracer content, and the mass flowrate of each phase is calculated based on these measured concentrations and the injection rate of each tracer.

The mass rate of liquid (Q_L) and steam (Q_V) is given by:

Equation 1.

$$Q_{L,V} = \frac{Q_T}{(C_T - C_B)}$$

$Q_{L,V}$ = Mass Rate of Fluid (liquid or steam)
Q_T = Tracer Injection Mass Rate
C_T = Tracer Concentration by Weight
C_B = Background Concentration by Weight

The mass rates calculated are valid for the temperature and pressure at the sample collection point. The total fluid enthalpy (H_T) can then be calculated using the heat and mass balance equation as shown below where the known enthalpies of liquid (H_L) and steam (H_V) are derived from steam tables at the sample collection pressure:

Equation 2.

$$H_T = \left(\frac{(Q_V \times H_V) + (Q_L \times H_L)}{(Q_V + Q_L)} \right)$$

Selection criteria for liquid- and vapor-phase tracers, techniques for metering and injection of tracers, and procedures for two-phase sampling are discussed in detail by Hirtz et al. (1993).

III. Field Validations

Comparative Test Results for Roosevelt

Validation of the tracer dilution technique was initially performed at the Roosevelt Hot Springs geothermal field in Utah. Dedicated production separators for each well allowed verification of tracer dilution tests with reference to orifice meter measurements of separated steam and liquid.

Tracer dilution testing was conducted at Roosevelt in April, 1992, during normal production of the three wells in service. Propane and potassium fluoride tracers were injected immediately downstream of the wellheads while samples were collected at two locations: 1) upstream of the production separator from sampling separators on the two-phase line; and 2) downstream of the production separator from the single-phase liquid and steam lines. Production separator pressures, liquid levels and orifice plate differential pressures for steam and liquid were recorded continuously by computer during the test periods of 2 to 4 hours.

Table 1.0 summarizes the Roosevelt comparative test results for steam flowrate, liquid flowrate, and total enthalpy, based on the 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.

Table 1.0 ROOSEVELT TEST SUMMARY

Production Separator Samples
Tracer vs. Orifice Measurements

Well Name	*STEAM FLOWRATE, kg/s*		
	Orifice	Tracer	Δ%
R-1	20.2	20.8	3.08
R-2	18.1	17.8	-2.11
R-3	11.8	11.6	-1.93

Well Name	*LIQUID FLOWRATE, kg/s*		
	Orifice	Tracer	Δ%
R-1	103	103	0.12
R-2	94.3	98.0	3.80
R-3	61.5	60.8	-1.03

Well Name	*TOTAL ENTHALPY, kJ/kg*		
	Orifice	Tracer	Δ %
R-1	1072	1079	0.65
R-2	1065	1049	-1.54
R-3	1065	1063	-0.22

Table 2.0 summarizes the comparative test results for steam flowrate and liquid flowrate based on samples collected upstream of the production separator. 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.

Table 2.0 ROOSEVELT TEST SUMMARY

Sampling Separator Samples
Tracer vs. Orifice Measurements

Well	STEAM FLOWRATE, kg/s		
Name	Orifice	Tracer	Δ%
R-1	20.2	(1)	–
R-2	18.1	(1)	–
R-3	11.8	13.2(2)	11%

Well	LIQUID FLOWRATE, kg/s		
Name	Orifice	Tracer	Δ%
R-1	103	105	2.17%
R-2	94.3	97.6	3.41%
R-3	61.5	149(2)	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

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 dispersion of the vapor-phase tracer was much more efficient than the dispersion of the liquid-phase tracer. The degree of mixing within the liquid phase over a short pipe run may be limited by the large mass of water and by the slug flow regime that exists in the two-phase lines of the Roosevelt wells.

Comparative Test Results for the Salton Sea

In order to determine the applicability of the tracer dilution technique in the Salton Sea geothermal field, a well producing to a dedicated separator was tested in September, 1993. Due to the high pressure, temperature, and salinity of the produced brine, the Salton Sea field presented extremely harsh conditions under which to test the tracer dilution technique. Propane and sodium bromide tracers were injected immediately downstream of the wellhead. As at Roosevelt, samples were collected upstream of the production separator with sampling separators on the two-phase line, and downstream of the production separator from the single-phase brine and steam lines. The distance between the injection point and sampling points was approximately 150 meters. Production separator pressures, temperatures and orifice plate differential pressures for steam and liquid were recorded at 5-minute intervals during the 4.5-hour test period.

Table 3.0 summarizes the comparative test results for steam and brine mass flowrates and total enthalpy. The enthalpy calculation involves a correction for the salt content of the brine, which at 20% by weight causes a significant deviation from the enthalpy of pure water at the same temperature and pressure. The difference between the tracer dilution and orifice flowmeter value was less than 5% for each parameter measured. The tracer results from the sampling separators and the production separator also demonstrate that representative samples can be collected from two-phase lines with sampling separators.

Table 3.0 SALTON SEA TEST SUMMARY

Tracer vs. Orifice Measurements

	Production Separator Samples		
Parameter	Orifice	Tracer	Δ%
Steam, kg/s	21.5	20.7	-3.86%
Brine, kg/s	147	152	4.61%
Enthalpy, kJ/kg	1019	1003	-1.60

	Sampling Separator Samples		
Parameter	Orifice	Tracer	Δ%
Steam, kg/s	21.5	20.6	-4.37%
Brine, kg/s	147	145	-1.38%
Enthalpy, kJ/kg	1019	1012	-0.68

Comparative Test Results for Heber

The tracer dilution method was initially validated in the Heber geothermal field in September, 1993. At Heber, all of the two-phase produced fluids are combined in the gathering system and separated at the power plant, so individual well flowrate comparisons are not possible. The first test conducted at Heber compared the enthalpy determined by tracer dilution to the enthalpy calculated from a flowing P-T survey of the well. Given that all entries to the wellbore were below the flash-point for this well, the enthalpy determined from the P-T survey is considered to be accurate.

During this first test, propane and sodium bromide tracers were injected directly through the wing valve on the wellhead. Samples were collected 15 meters downstream using sampling separators attached to the two-phase line. The total fluid enthalpy measured by tracer dilution was 744 kJ/kg, and the total flowrate measured was 93.6 kg/s. The total enthalpy calculated from the P-T survey was 742 kJ/kg, yielding a difference of only 0.27%.

A field-wide tracer dilution test conducted in March, 1994, allowed a comparison between the total mass flow of all production wells at Heber and the sum of the steam condensate flow and separated brine flow measured at the power plant by orifice meters. One of the 11 wells was re-tested in June, yielding a result closer to the expected value for that well. The total mass flow for all wells measured by tracer dilution (including the revised rate for the well re-tested in June) was 1085 kg/s, while the total flow measured at the plant during the March test was 1040 kg/s, a difference of 4.1 %.

IV. Operating Experience at Coso

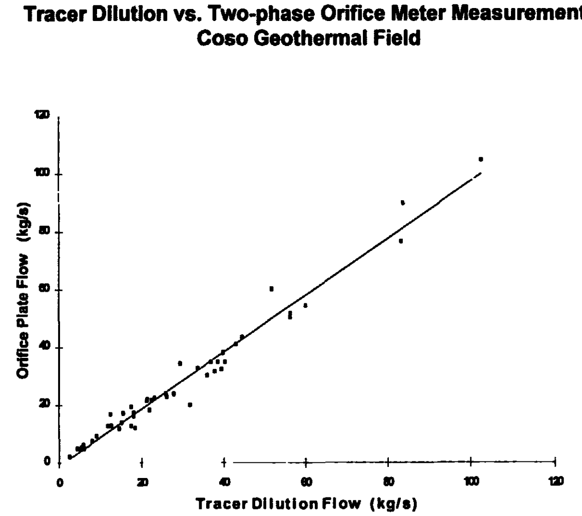
The Coso Geothermal Field produces two-phase fluids from fractured, crystalline rock at depths ranging from approximately 400 to 3,200 meters. Reservoir temperatures range from approximately 200 to 345°C. Commercial production began in July, 1987, with a 30-MW, dual-flash power plant. As of mid-1994, the field is producing 270 MW from nine turbines at four plant sites, using steam from 74 production wells. 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.

The initial flow tests of new wells in Coso during the early 1980's were performed with full-flow test separators. Since that time most initial well tests have been conducted with the James tube technique. The gathering system includes James tubes, atmospheric separators, and weir boxes as permanent components. A program of quarterly testing of all production wells using the James tube method was implemented in the summer of 1991. This allowed regular enthalpy and flowrate 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 because of environmental limits on H_2S emissions. A quarterly testing schedule using the tracer dilution technique was initiated in the winter of 1991-92 to establish a reliable means of determining enthalpies without diverting well flows. A total of 470 enthalpy tracer tests have been performed to date in Coso on wells ranging in enthalpy from 840 to 2760 kJ/kg.

Two-Phase Orifice Meter Correlations

In addition to the quarterly tracer dilution testing of all two-phase production wells at Coso, continuous flow monitoring is provided by orifice plate flowmeters installed in the two-phase production lines for each well. Total mass flowrates are calculated from two-phase orifice plate differential pressures (James, 1965) using the latest value of tracer dilution enthalpy for each well. This procedure allows approximate mass balances to be performed for the field on a daily basis. It also allows the monitoring of individual wells for major changes in productivity. A plot of total mass flowrates from the latest tracer dilution tests versus two-phase orifice meter measurements on Coso wells is shown in Diagram 1.0. The difference between tracer-based total mass rates and the orifice meter values is typically less than 20%. Deviations greater than 20% can usually be traced to calibration problems with the differential pressure meter or to plugged orifice meter pressure taps.

Diagram 1.0 Total Mass Flowrate Comparison



Tracer Mixing Evaluations

Adequate mixing of the vapor and liquid tracers in their respective phases is critical to accurate mass flowrate and enthalpy measurements, as demonstrated by the first tests performed in Roosevelt (well R-3). The typical distance between injection and sampling points at Coso is 18 to 58 meters with injection immediately downstream of the wellhead. The shorter pipe runs usually require a flow control valve between injection and sampling points for adequate mixing. The control valve provides agitation in a similar manner to a Venturi mixer, effectively distributing the tracers within each phase. The Heber comparative testing indicated that the pipe length can be as short as 15 meters with no control valve between the two points if injection occurs directly at the wellhead. The 90° pipe bend from vertical to horizontal at the wellhead tee provides substantial mixing of the phases.

Tracer mixing efficiency studies were performed during initial tracer mass flowrate and 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 only as crests in wave or slug flow or as an annular film.

Table 4.0 lists the results of these tests by comparing the liquid-tracer concentrations and the derived liquid flowrates for liquid samples collected simultaneously from the bottom and top ports.

Table 4.0 TRACER MIXING EVALUATION

Bottom versus Top Sample Ports

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

(1) Flow control valve upstream of sample point

In the first case shown in Table 4.0 for well C-4, two sets of bottom and top samples were collected at 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 flowrates derived from bottom versus top samples differ by only 3.3%.

The other cases shown in Table 4.0 are for 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.

For the test conditions encountered in these wells, the degree of tracer dispersion in the liquid phase appears to depend more on the mass rate of liquid flow than on the flow velocity or the two-phase flow regime. Still, sampling downstream of the flow control valve, as is routinely done, seems to provide adequate mixing of the liquid-phase tracer in all cases.

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 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 the vapor-phase tracer in the steam.

Table 5.0 TRACER MIXING, WELL C-5

Downstream versus Midstream and Upstream Sample Ports

Sample Port Location	Mixing Run, m	*LIQUID PHASE* Tracer ppm$_w$	Flow, kg/s	Δ%(1)
Downstream	18(2)	129	11.3	0
Midstream	12	131	11.1	-1.8
Upstream	3	228	6.29	-44

Sample Port Location	Mixing Run, m	*STEAM PHASE* Tracer ppm$_w$	Flow, kg/s	Δ%(1)
Downstream	18(2)	1.20	3.89	0
Midstream	12	(3)	(3)	-
Upstream	3	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

V. Error Analysis

A statistical error analysis for the tracer dilution technique was performed based on the known limits of error in the tracer injection rate, the analytical error in measuring the concentration of tracer in samples, and the 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 Institute of Standards and Technology (NIST). 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. These estimates of 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 the concentrations of tracers injected. The tracers are analyzed using the same standards and procedures as the geothermal fluid samples. The error 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.

Table 6.0 ERROR ANALYSIS FOR TRACER DILUTION TECHNIQUE

STEAM PHASE						
Gas Tracer Concentration	Calibration	Gas Tracer Injection Rate	Calibration	Sampling and Mixing Error	Analytical Error	Cumulative Error in Steam Flowrate
±2.0%	Same Standards and Procedures as Samples	±1.5%	NIST-Traceable Liquid Film Flowmeter	±2.0%	±2.0%	±4.3%

LIQUID PHASE						
Liquid Tracer Concentration	Calibration	Liquid Tracer Injection Rate	Calibration	Sampling and Mixing Error	Analytical Error	Cumulative Error in Liquid Flowrate
±1.0%	Same Standards and Procedures as Samples	±0.5%	NIST-Traceable Weight Standards	±5.0%	±1.0%	±6.7%

Cumulative Error in Total Enthalpy	±3.4%

VI. Conclusions

Based on the comparative enthalpy and flowrate testing in Roosevelt, Salton Sea and Heber and the fieldwide testing performed in Coso, the tracer dilution method is considered an accurate and cost-effective measurement technique for the mass flowrate of steam and liquid and the total enthalpy of two-phase flow streams. This technique makes it unnecessary to include either test separators or dedicated production separators for single wells in geothermal fluid gathering systems. Continuous monitoring of wells for major productivity changes and approximate field-wide mass balances can be adequately performed by two-phase orifice meter measurements using the enthalpy values determined by routine tracer dilution testing.

The tracer dilution method is also applicable to short-term well tests in cases where continuous measurements are not required, precluding the need for large atmospheric separators. This could be a valuable technique for testing exploration wells in remote areas where it can be difficult to fabricate and install large atmospheric separators. This method may also be employed to calibrate existing and/or experimental single- and dual-phase flow measurement devices.

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