Title
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Publication Date
1979-08-01

DR. 191

620
10-26-79

LBL-9090
GREMP-6
UC-66b

Measurement Requirements and Methods for Geothermal Reservoir System Parameters (An Appraisal)

MASTER

M. D. Lamers
Measurement Analysis Corporation

AUGUST 1979

Geothermal
Reservoir
Engineering
Management
Program

EARTH SCIENCES DIVISION
LAWRENCE BERKELEY LABORATORY
UNIVERSITY OF CALIFORNIA, BERKELEY

Prepared for U.S. Department of Energy under Contract W-7405-ENG-48

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Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price Code: A03

MEASUREMENT REQUIREMENTS AND METHODS FOR GEOTHERMAL RESERVOIR SYSTEM PARAMETERS (AN APPRAISAL)

MAC TECHNICAL REPORT #7806-01 AUGUST 1979

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Under UCLBL Contract #3695402

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ABSTRACT

One of the key needs in the advancement of geothermal energy is the availability of adequate measurements to aid the reservoir and production engineer in the development and operation of geothermal reservoirs, wells and the overall process plant. This report documents the geothermal parameters and their measurement requirements and provides an appraisal of measurement methods and instruments capable of meeting the requirements together with recommendations on identified deficiencies.

ACKNOWLEDGEMENT

The author would like to thank Dr. J.H. Howard and Mr. Werner J. Schwarz for initiating this study, and for their continued support during the performance of the work. Special thanks go out to all the members of the geothermal development industry who assisted in the establishment and refinement of the measurement performance requirements and provided inputs on current measurement methods. Final thanks to my colleague, Vince Martelli, for his assistance in preparing this report.

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1.0 INTRODUCTION

This report documents an appraisal of measurement methods for geothermal well system parameters performed by Measurement Analysis Corporation (MAC) for the University of California Lawrence Berkeley Laboratory (UCLBL). The specific objectives of the appraisal were the following:

1. Ascertain the key geothermal reservoir system parameters and quantify their associated measurement performance requirements.

2. Perform an appraisal of current measurement methods and instruments capable of meeting the measurement performance requirements, and

3. Provide recommendations for any key measurement deficiencies identified.

Emphasis of the appraisal was on geothermal fluid properties such as temperature, pressure, single and two phase flow rate, thermal energy, and composition; however, measurement needs and requirements are also included for in-situ reservoir formation properties and well physical status properties.

The Lawrency Berkeley Laboratory (UCLBL) has been assigned by the U.S. Department of Energy's Division of Geothermal Energy the task of developing and implementing a comprehensive plan for support of research and development in geothermal reservoir engineering (reference 1). Included as part of this task is the development of improved measurement techniques to aid the reservoir and production engineer in the development and operation of geothermal reservoirs, wells and the overall process plant. Due to the extreme hostile geothermal fluid and downhole measurement environments (high temperature and pressure, corrosion, scaling, etc.) combined with unique operational and geological formation conditions, the measurement techniques and instruments available are very limited or non-existent. Due to these measurement limitations, many needed parameters cannot be adequately measured thus leaving the reservoir engineer to make his own estimate. These limitations have resulted in a federally sponsored program to improve and/or develop key measurement systems to help speed or enhance the commercial development of geothermal energy as an economic, reliable and environmentally acceptable energy source. While some of the key instrumentation needs have been identified and programs initiated for their improvement/development (references 2 and 3), an overall comprehensive definition of the parameters of value, their quantitative measurement performance requirements, and an assessment of available current measurement techniques and instrumentation which might be utilized, improved or developed to fulfill the requirements was required. MAC was selected by UCLBL to perform this appraisal and report based on MAC's unique expertise and experience in areas of geophysical and process measurement systems, its familiarity with the geothermal energy development organizations and its ability to be unbiased in critiquing the various instruments.

A complementary appraisal was completed in early 1978 pertaining to characterization of geothermal brines (reference 4) and projects have been initiated to meet some of the deficiences (references 5-7). The appraisal and the improvement projects underway concentrate on downhole measurement requirements and methods for fluid chemistry/composition. As such, this review has not concentrated on fluid electrochemical sensing, sampling and analysis techniques.

The approach followed by MAC in performing this appraisal was to prepare a preliminary document defining the various key geothermal parameters identified together with a set of quantitative measurement performance requirements for each parameter and a list of possible measurement sensor techniques to be evaluated. This document was then distributed to technical representatives of geothermal energy development organizations for assistance in prioritizing the parameters, refining the quantitative measurement performance criteria, and obtaining inputs on specific measurement methods and sensors utilized or considered to date. A list of the organizations and individuals contacted is provided in Appendix A. Meetings were held with many of these individuals to obtain detailed data and feedback on their parameter measurement needs and performance requirements. The key geothermal parameters and measurement performance criteria were revised to incorporate industries' input and were used as criteria in evaluating measurement methods and instrumentation. The following report presents the findings of this appraisal.

2.0 SUMMARY

A comprehensive review of the parameters associated with process fluid, in-situ formation and well status required by the geothermal reservoir and production engineers was performed and their measurement requirements have been identified. Using these requirements, an appraisal of current measurement methods and instruments was performed and are summarized in this report, together with an identification of suppliers for the various types of instrumentation. This appraisal concentrated on basic sensor transducer techniques and their inherent limitations and potential for being used to meet the very hostile geothermal process fluid and downhole environments. Recognizing that commercially available electronics that can operate above about 200°C (∿400°F) is currently limited to a few basic components, downhole signal conditioning for well logging transducers will require thermal protection or await the development of special high temperature electronics. The U.S. Department of Energy's Division of Geothermal Energy is currently sponsoring several major projects for the development of high temperature components and integrated circuits (references 2-3). Fortunately, many sensor measurement techniques employ only a few basic electrical components in their sensing element and can currently operate or can be improved to operate at high temperatures if their support signal conditioning can be located in a low temperature environment.

Based on the appraisal, it appears that there are existing commercially available technology and measurement systems for all wellhead and process plant measurement requirements except for two phase flow measurements. However, downhole logging is primarily limited to tolerable fluid temperature and low resolution pressure measurements leaving the primary reservoir/producing zone parameters obtained from pressure transient testing techniques employing surface instrumentation. High resolution pressure sensors and flow rate logging tools employing turbine meters for operation up to 275°C are currently under development. Some of the simpler electrical induction and nuclear logging tools have been hardened for operation up to about 260°C (500°F); however, their reported performance to date in geothermal well environments is at best poor.

Inputs received from reservoir and production engineers in the geothermal development industry have almost unanimously agreed that the current measurement limitations which should receive the highest development priority to help advance the commercialization of geothermal energy are:

Priority 1	Production/fracture zone identification and orientation mapping
Priority 1	Well casing integrity
Priority 2	Production zone flow mapping
Priority 2	Porosity
Priority 2	Formation temperature during drilling operations

Besides these five key parameters, improvements in measuring all identified parameters will be helpful.

3.0 PARAMETER MEASUREMENT REQUIREMENTS AND METHODS

The parameter measurement requirements and methods presented in the following subsections have been assembled from inputs received from numerous organizations currently involved in geothermal energy development (see Appendix A); however, these parameters and requirements should not be considered all inclusive. It is very difficult to establish both the need and measurement performance requirements for geothermal energy applications. Due to the infancy of geothermal energy development, except vapor dominated reservoirs such as the Geysers, most requirements and efforts to measure process parameters have been associated with reservoir testing (i.e., well flow and interference tests). As such, the need and requirements for process plant start-up, operation and maintenance must be estimated and will vary depending on the specific reservoir and the fluid properties and type of energy conversion process employed. This is further amplified by the large number of different fluid flow conditions within a given process plant. For an overview of the variety of geothermal electric cycles and associated process fluid flow conditions, the reader is referred to reference 8. The range of measurement requirements and type of measurement methods vary widely, and no one 'universal' geothermal process parameter sensor system will exist. Instead, several types of sensors will be utilized and it is up to the user to select an 'acceptable' sensor for his application.

It should be noted that the downhole well measurement requirements and sensors presented and reviewed in the following subsections are further constrained by the current limitation of electromechanical logging cables. A preliminary evaluation of commercial electromechanical (EM) well logging cables in a high temperature air environment was sponsored by DOE in 1977 (reference 9). Sandia Laboratories is currently having additional cable tests performed to evaluate cable performance in a high temperature brine environment. The results to date indicate the best commercial monoconductor cables are good for less than 8 hours up to about 300°C, and multiconductor cables are good for less than 8 hours and up to about 260°C. Identified manufacturers of EM well logging cables are included in Appendix C.

3.1 FLUID PROPERTY MEASUREMENTS

To evaluate fluid property sensors, an overall perspective of the range of borehole and pipe sizes and associated access restrictions, fluid flow rates, viscosities, tolerable pressure losses, corrosion, abrasion and scaling constraints must be considered. Table 3.1-1 attempts to delineate some of these key constraints. Within the process plant and wellhead-surface fluid distribution system, there are numerous requirements for continuous or regular monitoring of process fluid properties, most of which are in high quality steam (χ>95%) or liquid lines. However, some low quality two phase fluid conditions can also be encountered. A major problem in two phase and supply liquid brine lines is scale build-up on contacting surfaces, especially protruding surfaces. The scaling, if not monitored, can cause thermal and electrical insulation of the sensors and associated error. The scale build-up will also change the geometry/cross section of calibrated sensor bodies such as orifice, drag bodies, etc.

TABLE 3.1-1

GEOTHERMAL FLUID MEASUREMENT CONDITIONS

o Downhole Conditions	
• Well diameters	- 5-3/4" to 14" - Production wells will typically be greater than 9" - Open hole washouts can range up to 30"
• Obstruction	- High pressure wellhead valves for tool access - Will range down to 3", typically <6"
• Borehole deviation	- Up to 45° (typically less than 20°)
o Process Pipelines	
• Orientation	- 0 to 90°
• Diameter	- 6 to 48" (less than 24" for liquid)
o Fluid Flow Rate	
• Wellhead (flowing well)	- $<2(10)^6$ lb/hr
• Process plant	- $<10^7$ lb/hr
• Shut-in-well	- Can have downhole flow (up or down) between two zones/fractures (measure down to 10 gpm)
o Maximum Pressure Drops to be Imparted by a Sensor	
	Liquid lines <5 psi
	Steam lines <2 psi
o Fluid Viscosity (temperature dependent)	
	Liquid: $0.05 \leq \mu \leq 1.4$ centipoise (Ref. 10)
	Steam: $0.01 \leq \mu \leq 0.025$ centipoise (Ref. 11, pp 4-67)

The following four subsections give the measurement performance requirements for the four key geothermal fluid parameters considered which are: 1) temperature, 2) pressure, 3) fluid flow rate and thermal energy, and 4) composition. Each subsection includes a description and comparison of various types of sensor techniques considered. Also included is a list of some of the manufacturers identified for each type of sensor. It should be noted that numerous other basic sensor techniques for these parameters exist, however, the methods presented are those which based on reviewed data are felt worthy of including in this appraisal study. For a detailed technical description of theory of operation of the various sensing techniques, the reader should refer to a basic text on physical techniques (i.e., references 12-14) and the manufacturers' literature.

3.1.1 FLUID TEMPERATURE

Process fluid temperature is always a high priority measurement parameter in geothermal energy systems from early exploration through process plant operations. Downhole temperature measurements are required primarily during exploration, well formation test/evaluation and start-up monitor phases of geothermal operations. For plant operations, there is a demand for reliable electronic readout sensors with remote monitor capability. Table 3.1.1-1 presents the geothermal fluid temperature measurement performance requirements.

TABLE 3.1.1-1

MEASUREMENT PERFORMANCE REQUIREMENTS FOR FLUID TEMPERATURE - T

	Downhole (supply & injection)	Wellhead & power conversion plant
Range	0°C T 315°C (1)	0°C T 315°C
Accuracy	±1°C = >~0.3%	±1°C = >~0.3%
Resolution	±0.5°C (2)	±0.5°C
Response time	1 sec preferred	10 sec
Exposure time	4 hrs to 2 weeks	continuous
Drift	1°C over measurement time	

(1) Estimate of maximum downhole hydrothermal temperatures are reported near 400°C (725°F), however 315°C (600°F) has been selected as the desired near term design goal that will cover most geothermal wells and 275°C as the minimum acceptable near term design goal.

(2) Resolution down to 0.1°C desired by some for possible identification of formation producing zones.

Besides being required as a direct process parameter, temperature is also required indirectly to calibrate/compensate most other parameter measurements such as pressure and flow rate sensors. While accurate and straightforward measurement techniques exist for obtaining process fluid temperatures, one limitation has been aired. The limitation is that of scaling and associated thermal insulation on pipelines and thermowells inserted in pipelines resulting in loss of calibration and/or lack of confidence in measurements.

Of the numerous types of basic temperature sensing techniques, only three electrical types appear worthy of consideration for geothermal application. These are 1) resistance temperature detectors (RTD's); 2) thermistors; and 3) thermocouples. For applications not requiring remote readout, bi-metallic thermometers with a dial readout are available. A bi-metallic sensor is also utilized in the Kuster Company's 'bomb' type high temperature well logging tool. A thermal fluid filled bulb-bourdon tube sensor is utilized in the Geophysical Research Corporation's (GRC's) 'bomb' type high temperature well logging tool. Maximum indicating temperature sensors configured as decals, pellets or markers that change color or melt at precise temperatures are available for special monitor applications such as within well logging and other downhole tools. Bi-metallic and mercury-glass thermometers can also be configured as maximum reading indicators; however, the maximum indicator can change in a shock or vibration environment. Table 3.1.1-2 provides a performance comparison for these six types of sensors. Of the three electrical sensors, resistance temperature detectors incorporating a platinum element are felt to represent the best all around sensor for geothermal process temperature measurements which can meet the stringent geothermal performance requirements. It should be pointed out that the performance data given in Table 3.1.1-2 is for the temperature sensor only. As such, most temperature measurement systems will not achieve these listed performances. This is especially true of the downhole 'bomb' type logging tool employing mechanical recording units.

The number of organizations manufacturing temperature sensors is considerable as is indicated by the partial list given in Table 3.1.1-3. For surface process line sensors, all the suppliers listed provide acceptable sensors. It should be noted that the Celesco Transducer Products is known to provide an accurate, reliable, 1 second response RTD in a pressure housing thermowell very suitable for incorporation in downhole logging tools.

TABLE 3.1.1-2

PERFORMANCE COMPARISON OF GEOTHERMAL PROCESS TEMPERATURE SENSORS

Performance Parameter	Resistance Temperature detectors (RTD's)	Thermistors	Thermocouples	Bi-metallic Thermometer	Thermochemical & Physical Melt indicators	Bulb-Bourdon Tube (thermal fluid filled)
Temperature range	-260° to 900°C	-100 to 400°C	-270 to 2000°C	-60 to 450°C	38°C to 1649°C Lables (38 to 600°C)	0 to 340°C
Accuracy	0.01% (<0.1°C)	1%	0.1%	1% (0.5% available)	1% (0.3% available)	1%
Sensitivity (signal level)	Good: +0.5%/°C (<0.1 V/°C with bridge)	High: -5%/°C, -0.5% linearized (<0.5 V/°C with bridge)	Very low, 1%/°C (<0.02 mV/°C)	Depends on dial size, etc.	NA	0.5% of F.S.
Linearity	Excellent: 1%	Poor: 10-20% Linearized: 2%	Poor: 10-25%	1%	NA	1%
Stability	Excellent	Poor	Excellent	Good	NA	Fair
Interchange-ability	Excellent	Good	Poor	NA	NA	NA
Size	Medium: ≥1/8" diam. by >1/4" long	Very small	Small	1" to 5" dial, stem dia. >1/8"	Typically >1/8"	Very large
Time constant	0.2 to 10 sec	0.05 to 10 sec	0.1 to 4 sec	10 to 30 sec	1 sec	Long
Cost	$25 to $1000	$2 to $300	$1 to $50		50¢ to $7	High
Comments	Best overall	Narrow span (typically <150°C)	Requires reference temp. junction	Can be configured w/maximum registering dial. Used in Kuster 'bomb' type high temp logging tool (span limited ~200°C)		Used in GRC 'bomb' type high temp logging tool (span limited ~150°C). Kuster also makes system rated for 260°C.

TABLE 3.1.1-3

MANUFACTURERS OF TEMPERATURE SENSORS REVIEWED

	Sensor Types				
	Electrical Sensing			Passive Indicating	
Manufacturer/Supplier	Resistance temperature detectors (RTD's)	Thermistors	Thermocouples	Maximum indicating sensors	Bi-Metallic stem thermometers
ARi Industries	X		X		
Barber-Coleman Co.	X	X	X		
Big Three Industries				X Thermochemical	
BLH Electronics	X		X		
Brooklin Thermometer				X Glass/Bi-Metallic	
Celesco Transducer Products	X	X	X		
C.S.Gordon Co.			X		
Fenwal Electronics		X			
Fischer & Porter Co.	X		X		
Foxboro Co.	X		X		
Hi-Cal Engineering	X		X		
ITT-Barton	X				
Markal Co.				X Thermochemical	
Matthey Bishop, Inc.	X				
Minco Products, Inc.	X		X		
Rosemont, Inc.	X				
Semco, Inc.	X		X		
Spectro Systems, Inc.				X Metal Pellets	
Sybron-Taylor Corp.	X		X	X Glass	X
Thermometrics, Inc.		X			
Victory Engineering		X			
W.Wahl Corp.	X	X	X	X Thermochemical & bi-metallic dial	X
Weed Instrument Co.	X				
W.H.Keseler Co., Inc.				X Glass	
Weston Instruments					X
Yellow Springs Instruments	X	X			
Omega Engineering	X	X	X		

Table 3.1.1-4 tabulates some of the temperature logging tools identified which are rated for operation above 232°C (450°F). There are numerous other logging tools manufactured with maximum temperature ratings up to 204°C (400°F). As can be seen from Table 3.1.1-4, only one prototype electrical temperature logging tool (#7) sponsored by the U.S. Department of Energy, currently meets all the geothermal near-term downhole requirements given in Table 3.1.1-1 and it is limited by the logging cable performance. However, several commercial logging companies have informally reported they will have temperature tools that meet or exceed the near-term geothermal requirements available in 1979. The slick line (wire) 'bomb' type tools incorporate the "Amarada" type self-contained scribe mechanical recorders. The prime limitation in extending the recording time of the 'bomb' type tools is their mechanical clock and chart drive recording system.

TABLE 3.1.1-4

PERFORMANCE COMPARISON OF DOWNHOLE TEMPERATURE LOGGING TOOLS FOR $T > 230°C$

#	Manufacturer, [Model]	Sensor Type	Range (°C)	Accuracy (±°C)	Resolution (°C)	Span (°C)	Response time (sec)	Maximum pressure (psia)	Maximum exposure @ T_{max} min	Tool Diam. (inches)	Cable type	Comments
1	Kuster Co., [600-1]	Bi-metal	0-370	±1	0.1	200	Slow	25,000	3 hrs	1-1/4	Slick line	User reported field accuracy of ±5°C
2	Geophysical Research, [RT-7A]	Thermal filled Bulb-Bourdon	0-343	±1	0.05	50	Slow	25,000	48 hrs	1-1/4	Slick line	User reported field accuracy of ±5°C
3	Triangle (N.L.McCullough), [Hi Temp Tool]	NA	0-265	NA	NA	265	NA	15,000	NA	1-1/4	1 Cond	
4	Dresser-Atlas, [Hi Temp Log]	NA	0-260	NA	NA	260	NA	20,000	5 hrs	1-11/16	1 Cond	Under development (Dewared Electronics)
5	Schlumberger, [HEL Temp Tool]	RTD	0-260+	NA	NA	260+	~1 sec	20,000	5 hrs	1-11/16	1 Cond	Higher temp unit reported under development (Dewared Elec.)
6	Gearhart Owen/Sandia, [Geothermal Temp Log Tool]	RTD	0-275+	±1	0.1	275+	~8 sec	15,000	Unlimited	1-11/16	1 Cond	Prototype only - incorporates high temp active/passive elec. (DOE Sponsored)
7	Systems, Science & Software, [Geothermal Temp-Pressure Tool]	RTD	0-315+	±0.5	0.1	315+	~1 sec	10,000	Unlimited	3	6 Cond	Prototype only - incorporates high temp passive elec. sensors (DOE Sponsored)
8	Los Alamos Sci. Lab., [Thermister Temp Tool]		0-235+	±4	0.1	50	NA	15,000	Unlimited	NA	4 Cond	Prototype only (DOE Sponsored)
9	Los Alamos Sci. Lab., [Thermocouple Temp Tool]	Thermocouples (7) in thermopile arrngmnt	0-235+	±1	0.5	0-235	~½ sec	15,000	6 hrs	NA	1 Cond	Prototype only - requires dewared ice bath for ref. junction (DOE Sponsored)
10	Denver Research Inst., [Temp-Pressure Tool]	RTD	0-260	±0.5	0.1	260+	~8 sec	2,000	Unlimited	2	6 Cond	Prototype only - similar to S^3 tool (#7 above). T-P limited by pressure sensor (DOE Sponsored)

NA = Data not available

3.1.2 PROCESS FLUID PRESSURE

Process fluid pressure is a required parameter for all phases of geothermal energy exploration, development and reservoir/plant operation. Due to the wide range in requirements and associated performance criteria for geothermal process fluid pressure measurements, the requirements have been divided into the following three use categories:

1 - Downhole pressure measurements for well interference testing;

2 - Downhole pressure measurements for well flow tests and other well logging operation and maintenance application;

3 - Wellhead and process cycle flow line pressure.

The specific measurement performance requirements for these are given in Table 3.1.2-1. All applications require DC (static) pressure response. These requirements represent a trade-off between what is desired and what can be tolerated by the user versus cost, reliability, and state-of-the-art pressure sensor performance.

Numerous commercially available ruggedized process pressure transducers exist that meet the wellhead and process plant requirements shown in Table 3.1.2-1. This is possible by isolating the transducers from the very high temperature process fluid with stand-off tubing or linkage to maintain the sensor and electronics below about 200°F (93°C).

Table 3.1.2-2 tabulates the pressure well logging tools identified which are rated for operation above 450°F (~230°C). As in temperature well logging there are more pressure well logging tools and services for operation below 400°F (~200°C). In comparing downhole performance requirements versus available pressure well logging tools, it is concluded that there are no available commercial tools which completely meet either of the downhole criteria, and the only prototype tool that meets the general requirement is cable limited. Due to the lack of any high temperature, high precision pressure gauges for downhole measurements, geothermal reservoir engineers have been using the Sperry-Sun, Inc. pressure transmission system consisting of a long capillary tube (.094"O.D.) which is suspended down the well with a pressure coupling chamber at the bottom and a low temperature precision pressure transducer connected at the surface. An inert gas or synthetic fluid in the tube provides the pressure transmission link. This technique requires calibration corrections for ambient pressure, coupling fluid expansion due to temperature, etc. Also, the suspended tubing length is limited to about 5,000 feet without experiencing excessive stretching and/or failure. Though reported desired by geothermal reservoir engineers to locate the observation well pressure sensor down at the producing zone depth to reduce sources of error, it has proved acceptable to locate the sensor in a less hostile location in the wellbore. For some reservoirs, acceptable pressure data has been obtained by locating the sensor below the minimum water level in the wellbore. One successful pressure sensing method reported for an interference test in Utah was to measure the change in height at the top of the wellbore water column in the observation well.

Due to the identified lack of commercial high temperature pressure sensors for incorporation in well logging tools, the following portion of this subsection will attempt to review basic pressure sensor techniques to provide a review of possible sensing techniques for this downhole pressure measurement deficiency.

There are many basic types of fluid pressure sensing techniques and numerous manufacturers for most types. <u>All</u> types experience some amount of thermal sensitivity shift and thermal zero shift which require compensation in order to meet the stringent accuracy and drift requirements for geothermal downhole applications. Basic fluid pressure transducers typically consist of two functional subsystem/elements: 1) a pressure to force/displacement element, and 2) a force/displacement to display signal transducer element. For electrical signal transducer elements, a third auxiliary element consisting of signal conditioning is required which may or may not be integral to the transducer.

Fluid pressure to force/displacement usually consist of one of the following types of elastic element configurations:

- Diaphragm - simple
  - convoluted
- Bellows - simple
  - convoluted
- Capsule (aneroid type)
- Bourdon tube - C type
  - helical (cylindrical)
  - spiral
  - twisted

No one type of pressure to force/displacement element is best or worst but what is important is the detailed mechanical design of each unit to provide a linear response over the pressure range and be insensitive to external environments such as temperature, case pressure, acceleration, etc.

TABLE 3.1.2-1

MEASUREMENT PERFORMANCE REQUIREMENTS FOR FLUID PRESSURE - P

Performance	Downhole: Interference Testing (1)	Downhole: Other Applications	Wellhead & power conversion plant
Range	20 psia < P < 5000 psia (2)	20 psia < P < 5000 psia (2)	20 psia < P < 500 psia Natural flow 20 psia < P < 3000psia Pumped flow
Accuracy	≤0.1% of full scale (FS)	≤0.25% FS	1% of working pressure
Resolution	≤0.005% FS (≤0.1 psi desired)	<0.05% FS	½% of working pressure
Response time	10 sec	1 sec	10 sec
Exposure time (measurement period)	10 days to 9 months	4 hrs to 4 days	Continuous
Drift (long term) (over measurement)	<0.01% FS (≤0.5 psia desired)	<0.1% FS	<1% FS

(1) Downhole interference pressure measurements will be in a constant high temperature fluid (±3°C)

(2)	*Current*	*Future*
Liquid dominated hydrothermal	P < 5,000	P < 5,000
Vapor dominated hydothermal	P < 700	P < 700 (can go to 1500 psia w/liquid build-up at bottom)
Hot dry rock	P < 7,000	P<10,000
Geopressured	P<15,000	P<15,000

TABLE 3.1.2-2

PERFORMANCE COMPARISON OF DOWNHOLE PRESSURE LOGGING TOOLS FOR T>450°F

#	Manufacturer and [Model]	Sensor Type	FS Pressure range(s) (psi)	Accuracy ±% FS (psi)	Resolution ±% FS (psi)	Max operating temp. (°F)	Response time (sec)	Max exposure time (hrs)	Tool Dia. (in.)	Cable type	Comments
1A	Geophysical Research, [Amerada PPG-3]	Helical bourdon tube linked to a stylus scribe recorder	500 to 25,000	0.2%	0.5%	650	Slow	48 hrs	1-1/4"	Slick line	Quoted accuracy & resolution very difficult to obtain in field. Max time limited to clock performance.
1B	Kuster Co., [KPG]		500 to 25,000	0.2%	0.5%	700	Slow	3 hrs	1-1/4"	Slick line	
2	Gearhart Owen/ Sandia Labs, [Geothermal	Bourdon tube linked linked to potentiometer	5,000	1% (50)	0.3% (15)	530+	<1 sec	Unlimited	1-11/16"	1 Cond	Prototype only - incorporates high temp active/passive hybrid electronics (uses Sparton Southwest sensor)
3	Systems, Science & Software, [Geothermal Temp-Pressure Tool]	Diaphragm with thin film strain gage	10,000	~0.2% (20)	0.04% (4)	600+	<1 sec	Unlimited	3	6 Cond	Prototype only - accuracy may be derated further due to cable performance; exposure time & temp further limited by cable (uses Bell & Howell sensor).
4	Denver Research Institute, [Temp Pressure Tool]	Helical bourdon tube linked to potentiometer	2,000	1% (20)	0.35% (7)	260	<2 sec	Unlimited	2	6 Cond	Prototype only - employs same passive concept as S^3 tool (#3 above) (uses a Gulton sensor).

TABLE 3.1.2-3

PERFORMANCE COMPARISON OF SOME COMMERCIAL PRESSURE TRANSDUCERS

#	Manufacturer and [Model]	Sensor Technique	Accuracy (overall) % FS	Resolution % FS	Stability & Drift	Max °F	Coefficnt	Maximum pressure range(s) (psia)	Size	Comments
1	Hewlett Packard, [2811B]	Diaphragm with oscillating quartz crystal	0.025%	infinite (0.01 psi typ)	0.01%/yr	300	?	11,000	1-7/16" dia. by 40" long	Accepted standard for precision downhole oil/gas well testing. Temp correction to ±1°C recorded.
2	Mensor, [Digital Quartz manometer]	Fused quartz helical bourdon tube w/optical sensor & electronic nulling	<0.2%	0.0005%	0 @ 3 mos (0.01%/yr)	122	0.0004%/°C	1,000	11" by 10" by 8½"	System temp control/compensation to ±0.2°C to achieve performance quoted. Also makes unit like #3 below.
3	Heise (Dresser), [Digiquartz]	C bourdon tube and servo force balance	0.05%	0.005%	NA	125	very small, 0.1%FS over range	10,000	4-3/8" by 6" by 16"	Sperry-Sun sells for use with their 'tube' pressure transmission system.
4	Paroscientific, [Digiquartz]	Bellows linked to vibrating quartz bar	0.1%	<0.1%	0.1%/yr	225	0.004%/°F	5,000	1.15" dia. by 3-1/4"	Hi temp @ pressure (530°F @ 10,000 psi) unit currently under joint development with Sandia Labs - will have high temp electronics.
5	Sundstrand Data Controls, Inc., [developmental]	Bellow linked via quartz structure w/force-balance & capacitor feedback	0.11%	0.004%	0.1%/yr ?	176	NA	500	1-5/8" dia. by 2"	Mfg claims higher pressure (5K-10K) unit is developable - basic sensor capable of higher temperature.
6	Setra Systems, [204/205]	Diaphragm w/capacitor plate displacement	0.11%	<0.1%	0.05%/yr ?	250	0.004%/°F	10,000	1-3/4" dia. by 2"	Basic sensor w/o integral electronics capable of much higher temperature.
7A	Heise (Dresser), [#CMM16]	C bourdon tube linked to dial and potentiometer	0.1%	0.01%	0.02%/yr	125	0	10,000	17-3/8" dia. by 3-1/4"	16" by 660 dial readout, electrical output also provided. Can operate up to 250°F w/external compensation.
7B	Mensor, [2792]		0.1%	0.01%	0.02%/yr	125	0	10,000	17-3/8" dia. by 3-1/4"	
8	Robinson-Halpern, [144]	Helical bourdon tube linked to differential transformer	0.15%	<0.01%	NA	165	0.1%/°F	10,000	6" by 6" by 4-1/4"	—
9	Bell & Howell, [CEC-1000]	Diaphragm w/thin film strain gage (sputtered)	<0.2%	<0.05%	0.1%/yr	600+	0.005%/°F	10,000	1" dia. by 2-1/2"	Mfgr claims higher accuracy & temp performance available
10	Bell & Howell, [CEC-4-361]	Diaphragm w/unbonded wire strain gage	0.25%	<0.05%	0.5%/yr	700	0.1%/°F	5,000	1-1/4" dia. by 2-1/2"	Fragile & slow temp response time (mfgr feels thin film will replace).
11	Kaman Sciences, [KP-1911]	Diaphragm with eddy current variable impedance coil	1%	0.1%	NA	1,000	0.1%/°F	5,000	5/8" dia. by 1-1/2"	—
12	Sparton Southwest, [890 HT]	C bourdon tube with wire potentiometer	1%	0.3%	NA	600+	0.1%/°F	10,000	1" dia. by 2-1/2"	—
13	Celesco, [P2]	Diaphragm w/variable reluctance transducer	1%	0.1%	0.5%/yr	250	0.2%/°F	10,000	1-1/4" dia. by 3-3/8"	Mgfr has built high temp (600°F) unit w/derated accuracy (~1½%).
14	Data Instruments, [MPA 1000]	Diaphragm w/bonded semiconductor strain gage	0.25%	<0.05%	0.5%/yr	250	0.001%/°F	5,000	1-1/4" dia. by 2-1/2"	—
15	Vernitech	C bourdon tube with film potentiometer	0.7%	<0.05%	0.5%/yr	185	0.01%/°F	10,000	2-1/2" dia. by 2"	—

Some types are more applicable for higher or lower pressure ranges; however, the key factor is in selecting the right type for the specific signal transducer element selected. The following is a list of the identified commercial force/displacement to electrical transducer methods employed in DC pressure transducers:

- Force on oscillating quartz crystal
- Longitudinal force on vibrating quartz beam
- Displacement of plates of a capacitor
- Displacement of differential transformer
- Servo force-balance incorporating bourdon tube or bellows with capacitor, differential transformer or viable impedance electronic transducer for displacement servo feedback
- Variable reluctance change by gap displacement in ferromagnet circuit
- Eddy current variable inductance change by gap displacement in coil induced electromagnetic circuit
- Displacement of potentiometer
- Strain gage on displaced/stressed member there are various types of strain gage elements utilized such as:
  - Thin film deposited
  - Unbonded wire element
  - Bonded foil
  - Bonded semiconductor
  - Diffused semiconductor
  - Welded metal sheath incapsulated

Due to the unavailability of commercial high temperature active electronics, the review has concentrated on items 1 and 2. However, it must be noted that ultimate accuracy, resolution and/or drift stability is in many instances, limited by the signal conditioning. Also, the inherent performance of the various types of sensors is to some degree controlled by the manufacturers' detailed design innovations, workmanship, and quality of materials and components. As such, it is difficult to determine inherent performance limits on any specific type of pressure sensor. However, it is possible to review, assess and document current performance of commercially available sensors.

Table 3.1.2-3 presents a performance comparison of commercial pressure transducers incorporating various sensor techniques presented above. The manufacturers and models listed are not all inclusive but were selected as representative of current typical state-of-the-art performance and there are numerous other manufacturers, especially for accuracies greater than about 1/2%. For most sensor systems described, their resolution and drift are limited by the signal conditioning electronics rather than the sensor. All sensors would require temperature compensation. It is also noted that sensors #7 through #14 as listed in Table 3.1.2-3 do not include signal conditioning as do the first six which have all their electronics integrally packaged. As such, selection of the 'best' sensor technique for high temperature (>450°F) downhole interference testing is not technically straightforward. However, in weighing current performance and cost with sensor system size, simplicity and the complexity of support signal conditioning electronics, the following techniques appear more developable for downhole precision geothermal pressure measurements:

- Bellows with vibrating quartz bar
- Diaphragm with capacitance sensor
- Bourdon tube with differential transformer
- Oscillating quartz crystal

Sandia Laboratories' Geothermal Technology Division is currently performing R&D on a new, high temperature (530°F) oscillating quartz crystal (reference 15) and is also working with Paroscientific, Inc. to harden their bellows with vibrating quartz bar sensor to operate up to 530°F (reference 3 and Table 3.1.2-3, #4).

To meet the other downhole pressure measurement applications, it would appear the diaphragm with thin film strain gage sensor represents the best candidate since an existing commercial sensor already meets all the performance requirements and the signal conditioning is relatively simple (reference Table 3.1.2-3, #9).

3.1.3 FLUID FLOW RATE

There are numerous types of process flow rate measurement systems capable of measuring liquid and/or vapor flow. However, the commercial systems capable of accurate and reliable performance in hostile geothermal process applications is at best limited to a few restrictive applications. Further, there are very limited and generally inaccurate methods for measuring two phase flow rates for even non-hostile, low volume flow rate process applications. As mentioned previously, besides very high fluid temperatures, a major sensor design/performance problem encountered in many geothermal supply liquid and two phase brine lines is scale build-up and corrosion on contacting surfaces, especially protruding ones.

The performance requirements for fluid flow rate measurements have been divided into the following flow states:

1. Single phase liquid (brine) flow
2. Single phase and high quality (χ>95%) vapor (steam) flow
3. Two phase mass flow and enthaply

Due to the ability of most single phase flow sensors to measure both liquid and vapor states, single phase including high quality steam will be discussed in the following subsection with two phase flow presented in the subsequent subsection.

3.1.3.1 SINGLE PHASE FLOW

Single phase flow of both liquid (brine) and high quality ($\chi \geq 95\%$) steam flow measurement systems will be addressed in this section. The performance requirements for the single phase liquid flow are given in Table 3.1.3-2A while the single phase and high quality steam flow requirements are given in Table 3.1-3-2B. Using typical pipe diameters and fluid viscosities given in Table 3.1-1 results in Reynolds Numbers that are above 10,000 for flow velocity above 1 ft/sec.

TABLE 3.1.3-2A

SINGLE PHASE LIQUID (BRINE) VELOCITY FLOW RATE-V_ℓ (ft/sec)

	Downhole[(1)]	Wellhead & Plant
Range	0.05% < V < 13 ft/sec	0.5 < V < 13 ft/sec
Accuracy	1% of Full Scale (FS)	1% of FS
Resolution	0.5% of FS	0.5% of FS
Response time	10 sec	10 sec
Exposure time	8 hrs	continuous
Liquid density range (lb/ft^3)	$20 < \gamma_\ell < 75$	--

(1) Based on Q_V < 4000 GPM per well.

Bi-directional flow sensing required for downhole low flow range (<2 ft/sec) with wellhead shut-in (non-flowing).

TABLE 3.1.3-2B

SINGLE PHASE VAPOR FLOW-V_g (ft/sec (PFS))

	Downhole	Wellhead & Plant
Range	V_g < 100 ft/sec	V_g < 225 ft/sec
Accuracy	2% of Full Scale (FS)	2% of FS
Resolution	1% of FS	1% of FS
Response time	10 sec	10 sec
Exposure time	<8 hrs	continuous
Vapor density range (lb/ft^3)	$0.03 < \gamma_v < 40$	$0.03 < \gamma_v < 2.8$

While there are probably hundreds of different flow meter techniques reported in the literature, the commercially available process flow meters reviewed have been categorized into the following types:

- Acoustic/ultrasonic
  - Travel time method
  - Doppler frequency method
- Magnetic
- Pressure head
  - Fixed obstruction (orifice/venturi)
  - Pressure probe (pitot)
  - Drag (target)
  - Variable orifice/movable obstruction
- Turbine
- Thermal anemometers
- Vortex
- Other

Some flow meter types give a measure of the spatial average velocity across the pipe. However, since the velocity profile across the pipe in laminar flow (non-turbulent) is not constant, flow measurement systems that sense velocity at one small spatial location must be calibrated to compensate for what may be very large discrepancies in the velocity measured versus the spatial average fluid flow velocity in the pipe. Insertion type flow measurement meters will be sensitive to this type of problem. They will sense a local velocity and the user must be aware and make the required calibration changes in order to obtain the average flow velocity of the system. Another problem will surface when the flow is so low such that air voids are created making the fluid a two phase liquid-air media making its velocity measurements impossible with single phase flow measurement meters. It is suggested that when the flow is so low to create air voids, the measurement be taken on a neck-down venturi section or vertical section be installed to eliminate and/or minimize the two phase flow in the sensor section.

Table 3.1.3-3 gives a performance comparison for identified downhole flow logging tools with temperature ratings exceeding 450°F. In reviewing this table, it is observed that the only logging tools available to date for high temperature wells incorporate turbine meters. A few other types of flow sensing systems have been developed for low temperature (<300°F) such as radioactive and thermal pulse tracer methods.

Table 3.1.3-4 gives a performance summary comparison for each type of single phase flow meter category reviewed. The performance data is felt to be representative of the various commercial flow meters on the market. Included in the table is the author's appraisal of the potential for each category in geothermal downhole logging and process pipeline measurement applications. The results indicate all techniques have potential for process plant application, however, it is felt that acoustic flow sensing techniques are more capable of being configured to meet the downhole geothermal flow sensing measurement requirements and environment.

Table 3.1.3-5 lists the manufacturers contacted and types of flow meters they manufacture. The following subsections will address each type of single phase flow meter category in more detail. Measurement techniques, ranges of measurements, pressure and temperature ranges, accuracies and applicability to geothermal well systems are closely scrutinized. Mass flow rates may be obtained by simple calculation of the product of the flow velocity, flow cross sectional area, and density of the fluid. The fluid density must be obtained from other measurement techniques. A discussion of fluid density sensors is included under two phase flow since the sensors reviewed will measure both single and two phase flow.

TABLE 3.1.3-3

DOWNHOLE FLOWMETER LOGGING TOOLS FOR T >450^{o}F

#	Manufacturer, [Model]	Sensor Technique	Range (ft/sec)	Accuracy (% FS)	Resolution	Max Temp (°F)	Max Pressure (psia)	Tool Dia. (inches)	Comments
1	Kuster, [Mark II]	Turbine	0.06 to 600	NA	0.1% FS	500	10,000	1-3/4	Slickline "Amerada" type scribe logger; poor flow path.
2	Schlumberger, [Flowmeter] (HEL)	Turbine	NA	NA	NA	500	20,000	1-11/16	Incorporates dewared electronics.
3	Gearhart-Owen/ Sandia Labs, [Flowmeter]	Turbine	NA	NA	NA	530	10,000	1-11/16	Developmental (incorporates high temp electronics). Bidirectional sensing.
4	Triangle (N.L.McCullough), [Spinner]	Turbine	NA	NA	NA	510	15,000	1-3/8	--
5	Dresser, [Atlas [Atlas continuous flowmeter]	Turbine	NA	NA	NA	500	18,000	1-11/16	Developmental (dewared electronics).

NA = Data not available.

TABLE 3.1.3-4

PERFORMANCE SUMMARY COMPARISON OF SINGLE PHASE FLOW METERS

	Flow range (FPS)	Accuracy (% FS)	Resolution (%FS)	Fluid state	Response time (sec)	Current temp limit (°F)	Max pipe size Inline (spool) insertion	Pressure drop (psi)	Scaling/ Abrasion susceptibility	Dynamic range	Potential for downhole geothermal logging	Potential for geothermal process plant	Comments
Acoustic travel travel time	0.02 to 100	<1%	<0.5%	liquid	<4	~500	12"/120" (clamp-on)	no obstruction	Low, none for clamp-on	1000:1	Good	Good to excellent	—
Acoustic Doppler	0.3 to 80	<2%	<1%	Liquid	<4	~500	/36" (clamp-on)	no obstruction	None for clamp-on	500:1	Good to excellent	Fair to good	Can be designed to work in 2Ø flow. Requires measurement or calibration for acoustic vel-C. Only clamp-on type currently available.
Magnetic	1 to 30	1%	<1%	Liquid	<2	360	48"/180"	no obstruction	Low	~100:1	Fair to poor	Fair to good	Pressure limited to ~300 psi; requires non-conductive liner.
Fixed obstruction head (orifice or venturi)	0.1 to 30 liquid, 10 to 300, vapor	~2%	<1%	Liquid or vapor	<2	>750	>48"	0.5 to 40	High	<4:1	Poor	Fair	—
Movable obstruction/variable orifice head	0.5 to 20	1-2%	~0.1%	Liquid or vapor	<2	>750	16"/-	2 to 20	High	~100:1	Poor	Fair	Unidirectional only.
Pressure head (Pitot type)	<1 to >30 liquid, >250 vapor	~1% of value	~0.1%	Liquid or vapor		>750	>48"	0.5 to 5	High	<4:1	Fair to poor	Fair to good	—
Drag body	0.3 to 15	1%	0.1%	Liquid	<1	>750	48"	<1	High	~10:1	Fair to poor	Fair	—
Turbine	0.5 to 50 liquid, 2 to 250 vapor	<1%	<0.1%	Liquid or vapor	<1	>750	14"/ 48"	<5	High	10:1 100:1	Fair	Fair	—
Thermal anemometer	0.03 to 30 liquid, 10 to 250 vapor, (Np > 10^4)	~1%	<1%	Liquid or vapor	<1	300	/any size	<<1	High	>100:1	Poor	Fair (film type only)	Temp limit can be raised. Fragile.
Vortex	1 to 20 liquid, 10 to 250 vapor	0.5%	<0.1%	Liquid or vapor	<1	<750	48"/108"	<6	High	>100:1	Poor	Good to excellent	Unidirectional; subject to scaling.

TABLE 3.1.3-5

IDENTIFIED MANUFACTURERS FOR SINGLE PHASE PROCESS LINE FLOW METERS

Manufacturer	Acoustic		Magnetic	Pressure Head				Turbine	Vortex	Thermal Anemometers
	Travel Time	Doppler		Fixed Obstruction	Pressure Probe	Drag Body	Variable Orifice			
Baird Controls		X								
Badger Meter, Inc.	X									
Barton-ITT								X		
Bennett Gervase, Inc.							X			
Brooks Instrument			X				X	X	X	
Controlotron Corp.	X									
Dieterich Standard Corp.					X					
Disa Electronics										X
Dupont Co., Instruments	X									
Eastech, Inc.									X	
Electronic Flo-Meters								X		
Engineering Measurements Co.								X		
Fisher & Porter Co.			X	X			X	X		
Flow-Dyne Engr., Inc.				X						
Flow Technology, Inc.								X		
Foxboro Corp.			X	X		X		X	X	
Fox Valve Devel. Co., Inc.				X						
Hersey Products, Inc.		X								
J-Tech Associates									X	
Leeds & Northrop		X								
Mapco, Inc.	X									
Polysonics, Inc.		X								
Ramapo Instrument Corp.						X				
R.M. Nikkel Co.								X		
Sybron-Taylor Corp.			X							
Tech Tube Corp.				X						

3.1.3.1.1 ACOUSTIC FLOW METERS

Under the general category of acoustic or ultrasonic flow meters are those that measure travel time and those that measure the doppler frequency shift.

The travel time flow meter shown schematically in Figure 3.1.3-1 operates on the concept that the travel time of a sound wave propagated between two transducers located at different axial stream positions is a function of the velocity of sound in the fluid, fluid velocity and the angle that the ultrasonic waves (beam) make with the direction of flow. The travel time, t_d, for the downstream direction is given by:

$$t_d = \frac{d}{C+V\cos\theta} \tag{1}$$

and the upstream travel time, t_u, will be:

$$t_u = \frac{d}{C-V\cos\theta} \tag{2}$$

where

C = velocity of sound
d = distance between transducer
t_d = downstream travel time
t_u = upstream travel time
V = fluid velocity
θ = the angle between the transducers and the fluid velocity vector

Solving equations 1 and 2 simultaneously will give the flow velocity, V, and velocity of sound, C, as a function of geometry and travel time. These equations are:

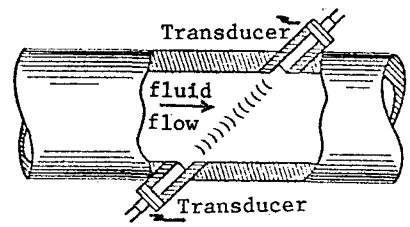
$$V = \frac{d}{2\cos\theta}\left(\frac{1}{t_d} - \frac{1}{t_u}\right) \tag{3}$$

$$C = \frac{d}{2}\left(\frac{1}{t_d} + \frac{1}{t_u}\right) \tag{4}$$

Equation (3) shows that this two transducer travel time flow velocity is not a function of the velocity of sound and may be determined from the geometry and the travel time of the sound phase. This travel time technique is limited to single phase flow with less than 10% undissolved solids to avoid timing errors from pulses reflecting from the particulate or bubbles. Several commercial acoustic travel time systems are reported being evaluated in geothermal process flow loops in the Imperial Valley KGRA (per discussions with organizations 7, 11 and 16 in Appendix A).

FIGURE 3.1.3-1

SCHEMATIC OF TRAVEL TIME ULTRASONICE FLOW METER



The doppler frequency flow meter, shown in Figure 3.1.3-2 below will measure average velocity of a single or two phase flow. The doppler flow measurement is identical to an active sonar system wherein the emitted acoustic wave is reflected from particulate and/or bubbles in the fluid and received at the place of emission with a frequency (doppler) shift proportional to the relative velocity between the transducer and the moving particles or bubbles. In the flow meter design, the transducer produces an acoustic wave train at a frequency, f_s. When the wave collides with a particle or air bubble (i.e., impedance mismatch), some amount will be reflected back to the receiving transducer. The frequency, f_r, of the received reflected wave train will be shifted in frequency.

$$f_r = f_s + 2f_s\frac{V\cos\theta}{C} \tag{5}$$

or

$$\Delta f = f_r - f_s = 2f_s\frac{V\cos\theta}{C} \tag{6}$$

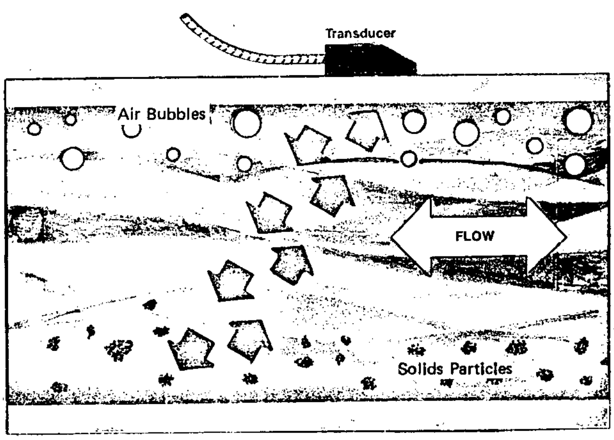
where

C = velocity of sound in the fluid
f_r = the received acoustic wave frequency
f_s = the transmitted wave frequency
V = the average fluid velocity (relative velocity between transducer and particle/bubble)
θ = the angle between the acoustic wave vector and the fluid flow vector

Assuming the velocity of sound in the fluid, C, is known or can be measured, then the average fluid velocity for the flow is proportional to the average frequency shift, Δf, and may be properly measured. For two phase flow with different phase velocities, the reflected ultrasonic wave energy will have two frequency shifts related to the two relative velocities. As such, spectral averaging of the received reflected wave must be performed to measure the different phase velocities. The doppler technique can incorporate a continuous wave (CW) mode which gives a spatial average or a pulse mode which provides distance and some spatial cross section (beam width) discrimination. The only doppler systems identified incorporate continuous wave acoustic transmission systems with separate transmit and receive transducers packaged side by side as one sensor assembly.

FIGURE 3.1.3-2

ULTRASONIC DOPPLER FLOW METER



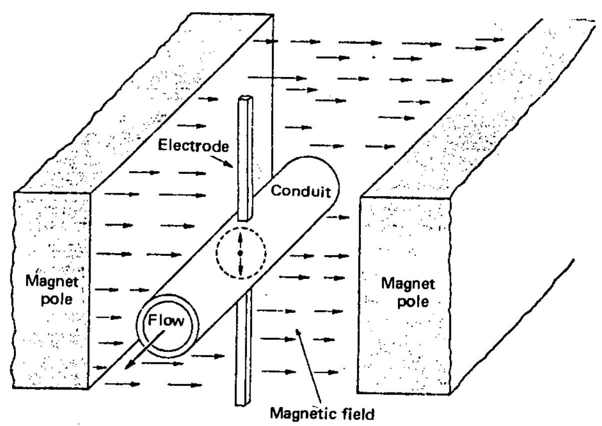
All the commercially available acoustic flow meters reviewed are for liquid, however, special units have been developed for gas/vapor fluids. Commercially identified travel time meters are available in spool insertion models and clamp-on models. The only identified doppler meters are clamp-on units. The clamp-on type sacrifices some accuracy, resolution and dynamic range performance while eliminating scaling and corrosion problems and minimizing cost. For downhole applications, it is the author's opinion that a pulsed doppler flow sensor tool combined with a automatic wave velocity sensor/calibration incorporated with the tool would prove to be a very accurate, reliable and wide dynamic range downhole flow measuring tool. Three major advantages of such a tool are: 1) it can measure velocity in an unobstructed portion of the borehole; 2) it requires no moving parts; and 3) high temperature ultrasonic (700°F), corrosion resistant sensors are easily developable. The acoustic travel time technique meets the latter two advantages also.

3.1.3.1.2 MAGNETIC FLOW METERS

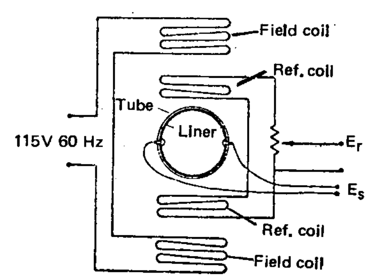
The operation of magnetic flow meters is based on Faraday's law of electromagnetic induction which states: the voltage induced across any conductor (fluid), as it moves through a magnetic field (meter apparatus) at right angles to the lines of flux, is proportional to the velocity of that conductor (fluid). A typical schematic diagram is shown in Figure 3.1.3-3

FIGURE 3.1.3-3

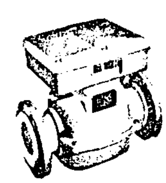
SCHEMATIC AND PICTORIAL FOR TYPICAL MAGNETIC FLOW METER



A - SYSTEM SCHEMATIC



B - ELECTRICAL SCHEMATIC



C - PICTORIAL OF TYPICAL UNIT

From the figure, the measured voltage across the electrodes mounted on the tube is expressed by the following:

$$E_S = KVBd \tag{7}$$

where

E_S = signal generated by liquid flowing through tube
K = a calibration constant
V = fluid velocity
B = magnetic flux
d = tube diameter

The meters are obstructionless with bi-directional sensing capability. This type of measurement can be performed in a dirty fluid with sludge and/or heavy coating, giving the fluid flow velocity as a linear function of the electrode signal across the tube. The inner liner of the flow meter must be made of a non-conductive material which presents pressure and temperature limitations for many geothermal process applications. Most commercially available systems can be provided with ultrasonic cleaners for the exposed electrodes.

3.1.3.1.3 PRESSURE HEAD FLOW SENSORS

Pressure head flow sensors comprise those types of sensors which relate 1) the pressure loss, ΔP, across a fixed obstruction such as an orifice or venturi; 2) the differential pressure, ΔP, between the dynamic and static flow stream pressures such as a pitot tube; 3) the force applied to a fixed obstruction in the flow tube such as drag body; or (4) the displacement of an obstruction resulting in a variable cross section such as a rotometer or variable orifice to fluid flow rate. The main advantage to these types of probes is simplicity, low cost and high temperature operation, while the main disadvantages are limited accuracy, dynamic range (except variable cross section) and for geothermal application, scaling and pressure drop represent added problems. However, due to their high temperature operation, head meters are most widely used flow meters used to date by the geothermal energy development industry. Their reported satisfaction with these head meters has at best been marginally tolerable.

A schematic of a drag force meter is shown in Figure 3.1.3-4 which measures flow in terms of dynamic forces acting as a fixed body in the flow stream. Bonded strain gages in a bridge circuit outside the fluid stream on a stainless steel flexure arm translate the force into an electrical output proportional to the flow rate squared. The following equation describes the drag force:

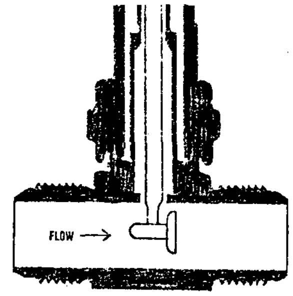
$$\text{Force} = C_d A \rho \left(\frac{V^2}{2g}\right) \tag{8}$$

where

C = drag coefficient
A = target area
ρ = fluid density
V = velocity
g = gravitational constant

FIGURE 3.1.3-4

SCHEMATIC OF DRAG FLOW METER



1.1.3.1.4 TURBINE FLOW METERS

There are numerous commercially available turbine flow meters. The general technique is to measure the liquid flow by directing the fluid through a multiblade turbine rotor. The fluid stream exerts a torque on the rotor causing it to rotate at an angular speed proportional to the fluid flow rate. The rotor is connected to some type of tachometer such as a pulse counter where the pulses are generated by each blade as it passes a sensing device placed in the housing.

The pulse frequency (Hz) can be shown to be linearly proportional to fluid velocity over a wide range of flow rates. Typical accuracies achieved are $\pm 1/2\%$. Since all turbine flow meters are viscosity sensitive to a degree, the fluid viscosity limits for a specific linear flow range must also be considered by the user. The turbine performance is generally given in the form of a curve of calibration coefficient as a function of pulse frequency over viscosity or

$$K = F\{f/\nu\} \tag{9}$$

where

F = a function of
f = pulse frequency (Hz)
K = calibration coefficient (Hz/unit velocity)
ν = fluid viscosity (ctk)

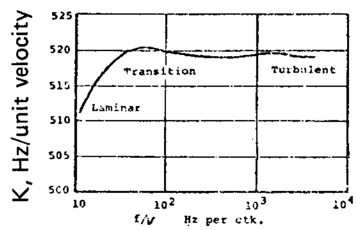
A typical calibration curve is shown in Figure 3.1.3-5a. (reference 12, pages 687 to 690). From this figure it can be observed that turbine flow meters are capable of operating over a wide range of viscosities with accuracies of $\pm 1/2\%$. Also shown in Figure 3.1.3-5b and c is the turbine sensitivity to viscosity.

Turbine flow meters shown schematically in Figure 3.1.3-6(a). They are manufactured both as a 'spool' inline type as shown in Figure 3.1.3-6(b) and probe type entering the pipe from one side (radial insertion) as shown in Figure 3.1.3-6(c).

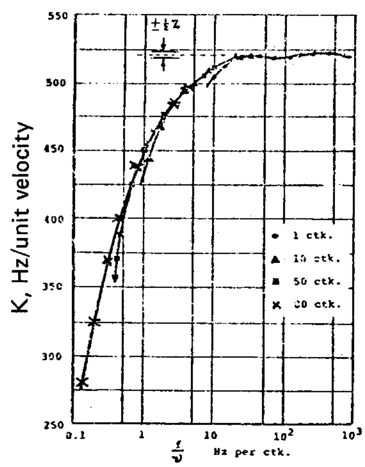
Flow in small pipes is strictly measured by the inline type while for large pipes (above 16 inches diameter) insertion types are used.

FIGURE 3.1.3-5

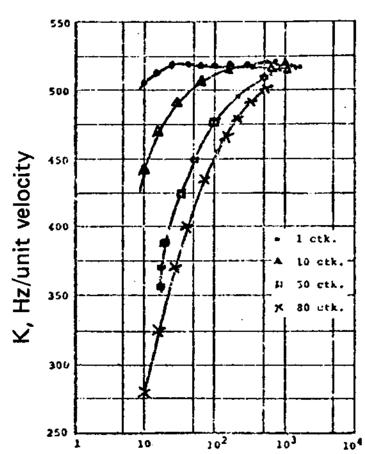
TURBINE METER CALIBRATION COEFFICIENT



(a) General shape of composite curve



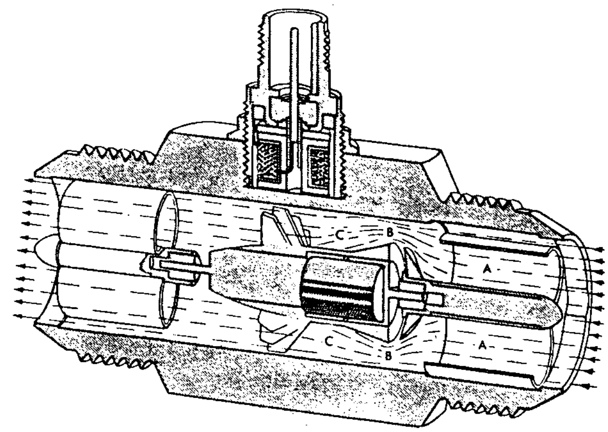
(b) Calibration coefficient "K" (Hz/v) vs Hz/ν



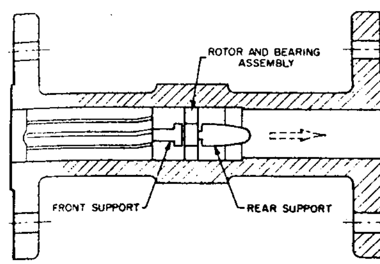
(c) Calibration coefficient "K" (Hz/V) vs. frequency (Hz/ν).

FIGURE 3.1.3-6

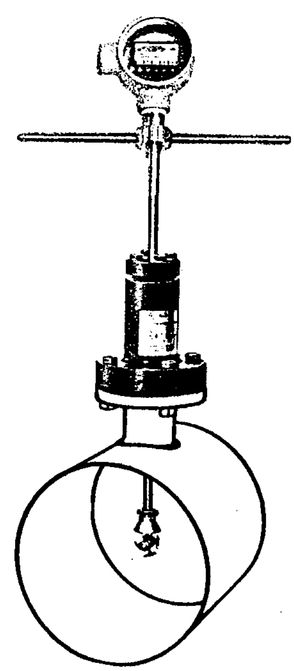
TURBINE FLOW METER SCHEMATICS



(a) Turbine meter flow schematic



(b) Inline (spool) type



(c) Insertion type

3.1.3.1.5 THERMAL ANEMOMETERS

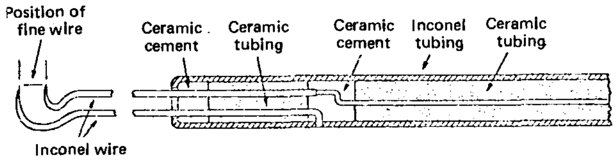
Thermal anemometers relate fluid velocity to the heat removed from a 'hot wire' or 'film' probe. Figure 3.1.3-7 shows a typical probe configuration. The exposed 'hot wire' probe typically consists of a platinum-plated tungsten wire suspended on two arms, and the 'film' type probe typically consists of a temperature sensitive conductive thin film such as platinum, on variously shaped bodies encased in quartz. The wire of film is electrically heated and the power supplied is a measure of the velocity of the flowing medium. Two control sensing methods are employed. The first is to supply a constant current through the sensing wire or film. Variation of flow velocity will cause a change in temperature, hence a change in resistance which thereby becomes a measure of flow. The second and most commonly employed method is to maintain constant temperature by varying the current input which similarly results in the measurement of flow velocity. The heat loss from the probe is also a function of fluid characteristics such as thermal conductivity, specific heat, density, etc., hence requiring proper calibration curves and/or measurement of the parameters that influence the probe heat loss. Exposed 'hot wire' probes are only used in gases and nonconducting liquids whereas the film probe can be used in conducting liquids such as geothermal brine.

The advantages of the thermal probes are their small sensing elements, short response time, high sensitivity, no moving parts, and good velocity ranges. While some of their disadvantages are their susceptibility to corrosion and scaling and they are delicate (break very easily).

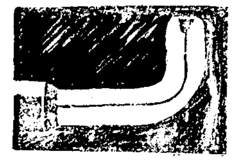
The hot wire probe is very delicate due to the fineness of the wire across the prongs. Thermal anemometers are typically used as laboratory flow instruments. The film sensor type is less delicate than the hot wire and has been used successfully in the ocean environment. However, the high temperature and corrosive liquid brine will cause pitting and scaling therefore giving erroneous measurement results. Also the liquid bubbles in steam will change the heat transfer characteristics causing a drift in the calibration. Based on the above information, both probe types are considered inadequate for geothermal well logging operation.

FIGURE 3.1.3-7

THERMAL ANEMOMETER CONFIGURATIONS



a. Exposed Hot Wire Inserted Probe Configuration



b. Film Inserted Probe Configuration

3.1.3.1.6 VORTEX FLOW METERS

The vortex flow meter works on the basic concept that a blunt object place in the fluid media will create a Karman Vortex with shedding frequency proportional to the fluid velocity. They are only designed for undirectional flow and as such are not a candidate for downhole applications. Vortex meters are available for both liquid and vapor (steam) fluid flow. The measured vortex frequency, f, is a function of the Strouhal's Number and is given by the expression:

$$f = \frac{sv}{d} \qquad (10)$$

where

s = Strouhal's number
v = fluid velocity
d = frontal width of the blunt object

The flow velocity will be proportional to the shedding frequency if Strouhal's Number is a constant. It was shown by experimental tests that Strouhal's Number has less than 1/2% deviation for Reynolds Number above 10^4. Strouhal's Number has a perturbation of $\pm 1\%$ for Reynolds' Numbers between 5×10^3 and 10^4. Below a Reynolds' Number of 5×10^3, the Strouhal's Number will increase rapidly making the flow meter inaccurate. It may be generally stated that vortex flow meters will operate with reasonable accuracies in a turbulent flow media.

The methods used to sense the vortex shedding frequency vary considerably and are typically the limiting performance element of the instrument. Table 3.1.3-6 presents a tabulation of the vortex meters reviewed giving this sensing technique and performance.

Manufacturers claim that there is no problem with fowling the blunt object due to the high turbulance. However, their use in geothermal process lines should be limited to relatively clean fluids. One unit is currently being used/evaluated in a liquid flow loop at one of the Roosevelt Hot Springs (Utah) KGRA well sites with excellent performance reported to date.

3.1.3.1.7 OTHER SINGLE PHASE FLOW SENSING TECHNIQUES

As noted previously, there have probably been more than a hundred flow velocity sensing techniques devised over the years. The following lists a few of those reviewed but were felt not to warrant serious consideration for use in hostile environment geothermal flow lines and/or have not been proven as a viable process fluid flow sensor.

- Nuclear magnetic resonance
- Laser doppler
- Radioactive tracer injection (travel time)
- Thermal tracer injection (travel time)
- Neutron activation tagging (travel time)
- Passive acoustic emission sensing
- Swirlmeters
- Fiber optical void fraction travel time correlator

TABLE 3.1.3-6

PERFORMANCE COMPARISON OF VORTEX FLOW METERS

Manufacturer Manufacturer, [Model]	Measurement technique	Type	Fluid state	Pipe size (inches)	Velocity range (ft/sec)	Accuracy/ Resolution (% FS)	Pressure drop (psi)	Rating pres/temp (psi/°F)	Comments
Brooks, [DS700-800]	Ultrasonic sensing of shedding frequency	Inline	Liquid	≤5	1 to 20	±1.0/0.2%	2.0	1440/248	—
Fisher-Porter, [10LV]	Strain gauge	Insert	Liquid	≤6	1 to 15	±2% rate	1.0	144/300	Less accurate than others @ high flow
Foxboro, [E81]	Pressure differential	Inline	Liquid	≤4	1.25 to 20	±0.5/	4.8	1500/400	—
J-Tech, [VF-500]	Ultrasonic sensing of shedding frequency	Inline and insert	Liquid and vapor	<4/<14	0.3 to 15, liquid 3 to 250, vapor	1.0/	nil	100/212	Claims will operate at lower $N_R \simeq 2000$; good above N_R of 5000.
Neptune-Eastech, [2300/2600/3600]	Thermistor (thermal anemometer)	Inline and insert	Liquid and vapor	48/108	1 to 20, liquid 10 to 250, vapor	0.5%/±0.25	6.0	1600/800	Accuracy will reduce to 2" for 5000 ≤; N_R < 10,000. Also makes units incorporating other techniques.

3.1.3.2 TWO PHASE FLUID MASS FLOW RATE AND ENTHALPY

There are many applications where the direct measurement of two phase geothermal brine-steam fluid flow rate and fluid enthalpy are desired. However, due to the unavailability of commercial two phase flow measurement systems for other than benign, small flow rate fluids, the geothermal industry has to date, improvised using indirect measurement techniques.

A continued measurement problem for geothermal reservoir engineers is the measurement of two phase mass flow rate and enthalpy in performing well flow tests. To date, the two methods employed with tolerable success are:

1. Use a separator and measure the single phase flow and enthalpy. Enthalpy can also be measured in the liquid zone downhole below the two phase zone.
2. The 'James' critical lip pressure technique (references 16-18).

The James' technique requires knowing the fluid enthalpy to relate critical lip pressure to mass flow rate or utilizing a separator down stream in conjunction with lip pressure and measuring the liquid mass flow and enthalpy. The James technique has not worked successfully in some areas due to excessive scaling and is considered to 'at best' yeild measurement accuracies of $\pm$20%. The primary complaint in using a separator is its size which can represent a portability problem for some well sites where roads and access are poor or limited. Another constraint at most well sites is that electrical power is not available thereby requiring a portable power supply. The current approach of most of the geothermal development organizations is to locate a separator into the area early in the reservoir testing/development phase to minimize the portability problem.

Many liquid dominated hydrothermal energy conversion cycles currently being developed or being considered incorporate the flashing of the geothermal brine into steam. In some of these cycles, the flashing begins within the wellbore or even possibly in the formation itself similar to vapor dominated reservoirs. Prior to entering a steam separator (scrubber), the quality can vary anywhere up to about 70%. Most 'scrubbed' fluids will have steam lines of qualities exceeding 98%; however, within the conversion process plant the steam quality in some lines may be as low as 80%.

Table 3.1.3-7 gives the range of two phase flow rates, enthalpy and quality with the desired flow measurement performance requirements. The only identified requirement for a downhole two phase flow measurement is a sensor to determine where in the borehole two phase flow exists such as identifying where the transition zone starts in liquid dominated reservoirs or determine if any liquid is entering the borehole in a vapor dominated reservoir producing zone. There is a requirement to measure downhole fluid velocity in the producing zone of liquid dominated reservoirs when the well(s) is shut-in (not flowing); however, the producing zone will be in a single phase liquid state with the well shut-in. Also the fluid will typically be in a single phase liquid state with the well flowing due to the downhole pressure at the producing formation.

For large diameter pipes (i.e., >3") most two phase sensing devices are of the in-line insertion type which sense only a small percentage of the overall pipe cross section or they incorporate a small flow sampling by-pass line where the sensor(s) are installed. A major problem with these insertion or by-pass techniques is the requirement that the flow regime be homogeneous; which is very difficult to achieve in other than high quality vapor. Figure 3.1.3-8 shows the two phase flow regimes encountered in horizontal and vertical pipes (reference 19). The only homogeneous flows where insertion type of by-pass sampling is valid are spray or annular dispersed flow. To improve the homogenity of two phase flow, 'flow homogenizers' consisting of vanes or orifices are installed directly upstream of the sensing devices. Even with flow homogenizers installed, most data reported in the literature indicate variances in the measurements exceeding $\pm$20% for low quality flow.

The understanding and measurement of two phase low quality (χ<95%) fluid flow parameters such as mass flow rate is an age old problem which to date has met with very limited success. Currently, there are numerous publications on two phase flow including one journal devoted specifically to the subject (International Journal of Multiphase Flow) and numerous research and development projects on the development of two phase flow measurement systems. For the past several years, the U.S. Nuclear Regulatory Commission (NRC), the Electric Power Research Institute (EPRI) and similar foreign country nuclear energy organizations have been sponsoring numerous research and development projects for two phase flow instrumentation for transient mass flow measurements in reactor safety studies (references 20-25). The nuclear reactor fluid measurement environment is similar to geothermal fluids (very high temperature water-steam), however, geothermal fluids contain scaling, corrosion chemicals and noncondensable gases.

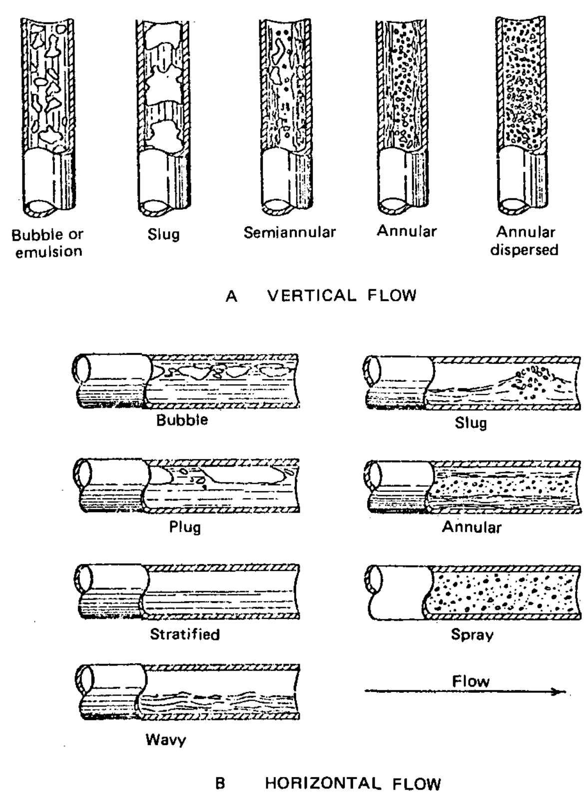
TABLE 3.1.3-7

TWO PHASE FLOW MEASUREMENT PERFORMANCE REQUIREMENTS FOR TWO PHASE FLUID FLOW

	Wellhead	Process Plant
Mass flow rate (W_T lb /hr)	$<2(10)^6$	$<10^7$
Enthalpy-h (BTU's/lb)	<1250	<1250
Fluid quality		
Liquid dominated	0-70 (typically <50)	>80 (typically >95%)
Vapor dominated	>90	typically >95
Slip velocity ratio $(V_v/V_\ell) = S$	$1 \leq S \leq 6$	$1 \leq S \leq 6$ (typically $S < 2$)
Vapor velocity (V_v ft/sec)	$0.5 < V_v < 100$	$0.5 < V_v < 100$
Measurement accuracy	5% of reading	±2% (h = ±0.5% for χ >98%)
Resolution	±2%	±1% (h = ±0.5% for χ > 98%)
Response time	<15 min	< 1 min
Exposure time	< 4 days	Once per day to once per week

FIGURE 3.1.3-8

FLOW REGIMES IN HORIZONTAL AND VERTICAL PIPES



One less stringent requirement for geothermal measurements is they do not require fast transient response. Based on a recent review group meeting wherein the status of all of these instrument related R&D projects were presented, together with reviewing numerous papers, tests and manufacturers' literature, it is this author's opinion that development of reliable instrumentation to meet the two phase geothermal measurement requirements will be a long, difficult, high risk project. Further, based on discussions with members of the geothermal energy development industry, the availability of such measurement tools does not appear to be critical to the development of geothermal energy. However, the availability of a small reliable low cost instrument is very desirable, especially for well flow tests.

The following subsections provide a brief discussion of two phase mass flow rate, enthalpy and density measurement techniques and sensors reviewed.

3.1.3.2.1 MASS FLOW RATE

Two phase water-steam mass flow measurement techniques will be divided into the following categories:

1. Direct mass flow rate sensing devices.
2. Computation using phase velocity, fluid temperature, pressure and average fluid density or void fraction/sensing devices.
3. Computation using volumetric measurement techniques such as quick closing valves or containers.
4. Computation using average fluid momentum (drag) and average flow velocity or average density sensing devices.
5. Separation of fluid into liquid and vapor streams followed by single phase mass flow measurements.

The types of direct or 'true' mass flow rates sensors reviewed were:

- Coriolis type
- Gyroscopic type
- Angular momentum type
- Thermal fluid heating type
- Thermal resistance type
- Differential pressure fluid injection loop

Of the above types, only one commercial unit was identified which can measure two phase water-steam flow. The performance of this gyroscopic unit is summarized below:

Type	Gyroscopic
Manufacturer	Micro Motion, Inc.
Fluid Type	Single or two phase homogeneous study state flow (poor performance reported with slug flow)
Max Flow Tube Size	2"
Accuracy	~1% of full scale
Max Fluid Temp	250°F
Pressure Loss	~5 PSI @500 lbs/min

The Electric Power Research Institute (EPRI) recently reported (reference 23) it was sponsoring an evaluation of this instrument.

Another prototype instrument recently developed for the nuclear reactor test program appears quite attractive for possible consideration in geothermal applications. The unit performance is summarized below:

Type	Coriolis
Developer	Kernforschungszentrum Karlsruhe (KFK); Karlsruhe, Federal Republic of Germany
Fluid Type	Single or two phase flow (no restrictions)
Max Flow Tube Size	80 MM (~3.15")
Max Mass Flow Rate	80 Kg/sec (~634,000 lb/hr)
Accuracy	<4% of reading for transient flow (better for steady state flow)
Max Fluid Temp	800°F
Pressure Loss	<2 PSI
Response Time	<.01 seconds

A third thermal heating mass flow meter manufactured by Agar Instrumentation was also reviewed. This instrument is designed for measurement of single phase hot (up to 800°F) corrosive gases and no data on its use with steam or two phase fluid was available.

3.1.3.2.2 FLUID ENTHALPHY AND QUALITY (CALORIMETRY)

While the computation of single phase liquid (water) and saturated of superheated steam enthalpy can be performed with measurements of temperature and pressure, measurement of the quality and/or enthalpy in two phase fluid flow is much more difficult, especially in low quality (χ<95%) non-homogeneous flow. Identified applications for measuring the quality of two phase geothermal fluid are:

1. During the performance of well flow pressure transient tests.
2. To periodically measure the performance of steam separators.
3. For measuring heat loss through segments of process (i.e., Geysers-between wellhead and input to steam generator).

While the measurement accuracies for well flow tests (application 1) are not stringent, the quality of the fluid is typically less than 50%, is not homogeneous, contains undissolved gases and is subject to severe scaling and corrosion on exposed surfaces. The reverse situation is encountered in the other two applications wherein high measurement accuracy is the principal difficulty with the fluid being high quality, relatively clean steam. A fourth measurement application, though not yet reported but required by the geothermal industry, is the measurement of enthalpy and/or quality in the fluid delivered to the procuring utility company at some location(s) in the conversion plant such as the steam at the turbine input or fluid at binary heat exchange input and the fluid at the injection well input.

LBL has recently contracted with Battelle-Pacific Northwest Laboratory to perform a detailed review and design tradeoff study for calorimeters to measure geothermal wellhead enthalpy (application 1 above). As such, the remaining discussion here will only briefly list the quality and enthalpy measurement techniques.

Steam calorimetry is a well developed science and several measurement techniques, instruments and associated sampling methods are well documented (reference 26). The two most commonly used are the throttling calorimeter and the separating calorimeter which are discussed in most thermodynamic texts. The throttling calorimeter is only suitable for measurement of very high quality steam while the separating calorimeter will measure any quality. One problem noted by a geothermal development organization working at the Geysers is that neither of these two units were acqurate enough for application #3 above. For this application, they were interested in accuracies of less than 2 BTU's per pound of steam (<∿.2% of reading).

Besides these two classic calorimeter methods, the following is a list of other methods considered:

- Condensing 'barrel' calorimeter (see reference 26)
- Heat exchanger/condenser technique (see reference 27)
- Measurement of average fluid density, $\tilde{\gamma}_f$, temperature and pressure (see following subsection)
- Measurement of average void fraction ($\tilde{\alpha}$), vapor and liquid phase velocities, temperature and pressure

The first two methods listed involving condenser and heat exchanges require sampling/by-pass techniques with their inherent sampling error problems, however, the density and void fraction/phase velocity techniques can be in-line devices. The heat exchange/condenser technique was proposed as a method for geothermal wellhead flow quality measurements but was not developed or tested. Both the latter methods require obtaining the density of the vapor and liquid from temperature and pressure conditions. The following two equations give the relationships utilized:

(11) $\tilde{\gamma}_f = \chi\gamma_v + (1-\chi)\gamma_\ell$ — fluid and phase density and quality

(12) $\left(\frac{1-\tilde{\alpha}}{\tilde{\alpha}}\right) = \left(\frac{V_v}{V_\ell}\right)\left(\frac{\gamma_v}{\gamma_\ell}\right)\left(\frac{1-\chi}{\chi}\right)$ — void fraction phase velocity, density and quality

where

$\tilde{\gamma}$ = average fluid density
γ_v = vapor density
γ_ℓ = liquid density
χ = fluid quality
$\tilde{\alpha}$ = average void fraction
V_v = vapor velocity
V_ℓ = liquid velocity

Current commercial identified sensors to measure void fraction employ fiber optic techniques which are not currently suitable for use in geothermal fluids. However, several conductivity probes developed for the nuclear industry (see paper by Creare, Inc. in reference 23) appear to give good performance and appear viable for use in geothermal pipelines. The disadvantage of this void fraction technique is that measurement of the phase velocities are also required, a very difficult measurement.

3.1.3.2.3 SINGLE AND TWO PHASE FLUID DENSITY

As presented previously, fluid density measurements are used to compute mass flow rate in both single and two phase flow streams and can be used to compute quality. The single phase flow meters presented in Section 3.1.3.1 provide a measurement of fluid velocity (i.e., ft/sec), which together with the pipe or borehole cross section can provide a measurement of volume flow rate (i.e., gallons per minute). However, in many geothermal process applications, the desired fluid parameter is for mass flow rate (i.e., lbs per hour). For high quality (χ>95%) and superheated steam flow lines, the density can be computed by measuring the temperature and pressure and using steam tables. Temperature and pressure can be used to obtain density for most single phase liquid flow lines; however, some emperical data must be obtained for fluid with large amounts of dissolved solids. Measurement of average fluid density in two phase flow streams is used to compute quality with the aid of fluid temperature and pressure measurements. This together with separate measurements of vapor and liquid flow velocities and flow cross section, are then used to compute mass flow rate.

For applications requiring an 'in-line' actual measurement of process fluid flow density, the following three types of commercial sensors are available:

- Vibrating 'U' flow tube
- Vibrating emersed tube
- Gamma beam densitometer

The two vibrating tube techniques are based on the principle that the natural frequency of the tube is proportional to the mass of the fluid flowing through and around the tube. The vibrating 'U' tube is only available for a small by-pass sample flow stream (~1" diameter) where the vibrating emersed tube is available in a by-pass or insertion design. These units are available to measure liquid and vapors and <u>will also function accurately in two phase flow streams</u>.

The main problem/limitation for two phase flow density is in obtaining a homogeneous flow stream so the sample/by-pass flow or insertion sensor area is representative of average density in the pipeline. Also the units are susceptible to scaling with degradation in accuracy.

The gamma beam densitometer incorporates a nuclear source that radiates a calibrated gamma beam through the liquid to a detector. The radiation reaching the detector produces a signal which is inversely related to fluid density. The source and detector can be configured as a 'clamp on' sensor, however, scale build-up on the pipe wall will degrade its performance. Several well logging tools are available for downhole fluid density measurements that employ gamma beam densitometers, however they are not designed for high temperature operation.

Table 3.1.3-8 provides a performance comparison for the fluid densitometers reviewed. As seen from this table, the units manufactured by Agar appear to meet the geothermal temperature and pressure environments and have high accuracy and resolution.

Besides these three types of commercially available fluid densitometers, R&D densitometer programs are being sponsored by the Nuclear Reactor Test Program include quick closing valves, pulsed neutron activation, multiple (3) gamma beams, slewed gamma beam, and vibrating emersed structures (beams) (see references 22-24). Except possibly for the quick closing valves and the vibrating beam, the other techniques do not appear to be practical for geothermal applications. It would appear that a by-pass line employing two quick closing valves to trap the liquid followed by removing or condensing the vapor and weighing the liquid would provide an acceptable method with the disadvantage of being a by-pass sampling device, quite tedious and slow, yielding one measurement at a time.

TABLE 3.1.3-8

PERFORMANCE COMPARISON OF FLUID DENSITY SENSORS REVIEWED

Manufacturer and [Model]	Sensing techniques	Range (SGU)	Accuracy (% FS)	Resolution (% FS)	Span (lb/ft^3)	Max fluid temp/pressur (°F/psi)	Flow tube diam	Comments
Agar Instrumentation, [FD700 and ID700]	Vibrating emersed tube	0.1 to 1.2 (liquid), 0 to 0.06 (vapor)	0.1	~0.01	>0.6 >0.025	1000/>2000 1000/>2000	~1"	Configured in both bypass sampling & insertion models
Automation Products, [Dynatrol]	Vibrating 'U' flow tube	0.5 to 1.2 (liquid)	0.02	~0.02	--	550/1000	1/2"	--
Barton-ITT	Vibrating emersed tube	0.3 to 1.2 (liquid) 0.008 to 0.12 (vapor)	0.1	0.01	0.6 to 2 1 1 to 5	200/>2000	~1"	Both bypass/ sampling and insertion models
Halliburton Services, [B2A]	Vibrating 'U' flow tube	0.6 to 1.8	1	<0.1	6 to 30	180/50	1¼"	Bypass/sampling design only
Micro-Motion, Inc., [L100A]	Vibrating 'U' flow tube	--	1	~1	--	60/	1"	Bypass/sampling only; also configured for direct mass flow measurement
Ramsey Engineering Co. (Texas Nuclear Div.), [SG Series]	Gamma beam	0 to 1.4	1	<0.1	0.01	Clamp-on limited only by ambient conditions	Very sml diam γ beam thru fluid/pipe	Clamp-on type

3.1.4 FLUID COMPOSITION

As noted in the introduction, an assessment of measurement requirements and techniques for the chemical composition of geothermal brines has been performed (reference 4), and development projects have and are being instituted by the U.S. Department of Energy's Division of Geothermal Energy for electrochemical probes to measure conductivity, Ph, etc. (references 5-7). Also, LBL has contracted to Terra Tek, Inc., for the improvement of the "McDowell" fluid partial pressure instrument for in-line measurement of the concentration of CO_2 in geothermal fluids (reference 28).

Table 3.1.4-1 lists the fluid composition parameters of interest and their ranges. A list of the important chemical constituents of geothermal brines is given in Table 3.1.4-2. Measurement methods identified for fluid composition properties are:

- Pipeline fluid/chemical sampler
- Downhole borehole fluid sampler
- Downhole formation fluid sampler
- Electrochemical probes (conductivity, Ph, etc.)
- Light blockage flow tubes for undissolved solids
- In-line partial gas pressure technique for total undissolved gas

A good presentation of sampling and analysis methods is contained in reference 7. The current measurement techniques to obtain a sample of the fluid are usually at the wellhead, however, downhole fluid samples have also been utilized. The ability to sample geothermal fluid density downhole is currently very limited. Most samples collected are either mixtures from several producing formations or contaminated with water from other locations transited by the sampler in the borehole. Some of the identified developers and manufacturers of downhole fluid samplers are given in Table 3.1.4-3. Various deficiencies were reported by the geothermal industry with the commercial downhole samplers (#2 and #4) such as not obtaining a representative sample due to inability to purge and to hold at sampled temperature and pressure.

TABLE 3.1.4-1

FLUID COMPOSITION PARAMETERS

No.	Parameter	Range
1A	Total dissolved solids (in ppm)	1K to 300K (<10K typical)
1B	Dissolved solids chemical composition	See Table 3.1.4-2
2	Undissolved solids (suspended matter) particle size (in microns)	1 μm to 800 μm
	parts per milliliter	--
3	Non-condensable gases	
	H_2S (in ppm)	<75
	CO_2 (in ppm)	<500
4	pH	3 to 9.5

TABLE 3.1.4-2
(Ref. 4)

RANGES AND CONCENTRATION OF IMPORTANT CHEMICAL CONSTITUENTS OF BRINES

CONSTITUENT	RANGE ppm (nominal)	Maximum ppm
Chloride	100 - 1,000	260,000
Sodium	100 - 1,000	87,000
Sulfate	50 - 500	84,000
Calcium	10 - 100	65,000
Magnesium	1 - 10	40,000
Potassium	50 - 140	30,000
Aluminum	0.5 - 5	7,200
Iron	1 - 10	4,600
Silica	50 - 500	1,060
Ammonium	0.5 - 5	1,050
Nitrate	Not estimated	1,020
Carbon Dioxide	0.5 - 5	500
Lead	0.5 - 5	110
Hydrogen Sulfide	Not estimated	75
Silver	Not estimated	2

TABLE 3.1.4-3

IDENTIFIED MANUFACTURERS/DEVELOPERS OF BOREHOLE FLUID SAMPLES

#	MANUFACTURER/DEVELOPER	SAMPLER TYPE	COMMENTS
1	Amoco/Gearhart-Owen Industries	Incorporates a mechanical pump powered by stroking monoconductor cable. Uphole monitoring of conductivity sensor in single sample bottle identifies when sample is stabilized (i.e., uncontaminated).	Prototype only. Temperature limited.
2	Kuster Company	Slickline with single sample bottle actuated by preset clock. Rated for 600°F and 20,000 PSI.	
3	Los Alamos Scientific Lab.	Two sample volumes independently actuated by motor driven valves controlled uphole. Rated for 200°F and 5,000 PSI (see reference 29).	Currently being uprated to 275°C at 10,000 PSI
4	Prodelco Engineering Ltd.	Klyen subsurface sampler is a single sample bottle on a slickline. Unit is actuated by jerking on slickline. Rated for 600°F and 34,000 PSI.	
5	U.S. Geological Survey	Small diameter tube inserted into well with sample bottle. Actuated (sealed) by applying pressure in tube at surface. (see references 30-31)	

3.2 IN-SITU FORMATION AND WELL STATUS MEASUREMENTS

Besides the measurement of geothermal process fluid properties, there are many key in-situ reservoir formation parameters that must be measured in the development and operation of the reservoir. Also, tools to measure physical status of wells such as orientation and casing condition are a necessity in the development and operation of the well and process plant.

While many of the intrinsic parameters to be measured in a geothermal well are the same as those for an oil or gas well, the range of the parameters, their priority and the well environment differ significantly. Geothermal wells are typically much hotter and located in different geologic formations (i.e., igneous or metamorphic versus sedimentary for oil and gas). Permeability and reservoir size are key measurement parameter objectives for both geothermal and petroleum wells; however, the range of permeability, its controlling parameters (i.e., fracture size, quantity, etc.) and parameters governing the reservoir size/potential vary significantly. Many of the existing petroleum logging tools, though not optimum, could provide useful data for the geothermal industry if they would operate at high temperature. A very hostile deep oil or gas well may reach a bottom hole temperature of 260°C (500°F) while many geothermal wells have reported temperatures in excess of 275°C (527°F) with a few wells reported in excess of 350°C (662°F). Recently, there has been a large increase in the use of steam injection for secondary oil recovery with accompanying operating temperatures approaching 275°C (527°F). These fossil energy high temperature well logging requirements combined with the small but increasing requirements of the geothermal industry are providing some incentive for the commercial well logging tool development and service organization to "harden" some of their logging tools. To date, however, there are very few formation parameter and well inspection tools capable of operation above about 204°C (400°F).

This inability to obtain key formation and well status measurements is reported to be one of the key factors limiting the development of geothermal energy. In some instances it has been possible to cool the well down using drilling mud or other fluid to perform the logging operation. Cooling of a geothermal well must be considered the lesser of two problems - no measurements versus distorted measurements, and risk of damage to the well casing. Also in some wells this cooling operation can have a long term adverse effect on the well performance.

Table 3.2-1 gives a list of the identified formation and producing zone parameters and their associated measurement requirements. The only well physical status measurement identified were:

1. Well casing integrity - identification of flaws (cracks, fractures, cement bond failures, etc.) on both internal and external surfaces.
2. Well orientation/survey.

Of all the parameters reviewed and discussed with the geothermal energy development industry, current inability to obtain measurements of the following five parameters were felt to represent the most severe measurement limitations for reservoir and production engineers in their efforts to develop geothermal energy as a viable commercial source of electric power:

Priority	Parameter
1	Fracture orientation in producing formation zone
1	Well casing integrity
2	Location/identification of permeable producing and theft zones
2	Formation porosity
2	Formation temperature during drilling operations

All the above parameters are derived by the measurement of one or more underlying variable parameters which can be related to the desired parameter. Therefore, the priority and need for these underlying variable paremeters such as acoustic wave velocity or electrical resistivity will differ depending on the specific well logging measurement method utilized (i.e., electrical and electromagnetic vs radioactivity vs acoustic vs optical vs gravity vs mechanical vs other).

Table 3.2-2 lists some of the identified well logging techniques and tools that are felt to be worthy of further consideration for providing measurements of the above high priority geothermal parameters. Due to the varied downhole environments and formations, it is felt that no one singular logging tool will be best for all geothermal applications.

TABLE 3.2-1

FORMATION AND PRODUCING ZONE PARAMETERS AND MEASUREMENT REQUIREMENTS

	Range	Accuracy	Resolution	Comments
Formation permeability: K (Darcys)	$10^{-3} < K < 3$	5% of reading	--	Typically obtained from pressure transient tests
Location/identification of permeable producing and theft zones	Small changes in vert. flow when shut in (up & down)	--	--	High priority measurement
Producing formation, grandular size (microns)	1 to 100	--	--	Can be obtained from cutting samples
Fracture size: δ (millimeters)	$0.5 < \delta < 10$ typical (can be larger)	±0.5	±0.5	Some fractures in Geysers reported to be ~3/4"
Fracture spacing: Δ (number per meter)	$1 < \Delta < 100$	5%	5%	Can be only one producing fracture in producing zone
Fracture orientation with borehole: Θ_B	0 to 90°	2°	1°	Very high priority measurement
Fracture orientation in-situ formation: Θ_F	0 to 45°	2°	1°	Very high priority measurement
Formation porosity	1 to 30%	±1%	±1%	High priority measurement
Formation temperature: T_F (°C)	$100 < T_F < 400$	±3°C	±2°C	Very high priority measurement during drilling operations
Vertical heat flow: Q_h ($Q_h = q/A = kb$) (μCal/sec - cm^2) = HFU's	$0.5 < Q_h < 20$ nominal ~6	±10% of reading	--	--
Thermal conductivity: k	$3(10)^{-3} < k < 1(10)^{-2}$	±10% of reading	--	Usually obtained from core samples
Vertical temperature gradient: b dt/dL (°C/km)	$40 < b < 1000$ nominal ~100	--	--	--

TABLE 3.2-2

POSSIBLE WELL LOGGING TECHNIQUES FOR HIGH PRIORITY GEOTHERMAL PARAMETERS

Parameter	Logging Techniques: Sensor Type	Logging Techniques: Description
Fracture orientation in producing formation zone	Acoustic	Borehole televiewer Caliper Circumferential log Holographic log Velocity log
	Electromagnetic	Dipmeter (FIL)
	Optical	Video (TV)
Well casing integrity	Acoustic	Borehole televiewer Caliper Cement bond log
	Electromagnetic	Eddy current magnetic log
	Optical	Video (TV)
	Mechanical	Caliper (high resolution >30 arm)
Location/identification of permeable producing and theft zones	Acoustic	Passive listening (emission) Flow velocity (travel time or doppler
	Thermal	High resolution temperature log
	Radioactive	Tracer log
Formation porosity	Nuclear	Various
	Mechanical	Formation fluid sampler
	Other	Various
Formation temperature while drilling	Thermal	Bottom hole temperature log Thermophysical pellets in drilling fluid Real time logging
	Nuclear	Neutron activation techniques

4.0 CONCLUSIONS AND RECOMMENDATIONS

Based on this appraisal of measurement requirements and methods for geothermal reservoir system parameters, it is concluded that the availability of commercial instrumentation for wellhead and process plant parameters have many deficiencies and downhole well logging tools for obtaining measurements of the key parameters are non-existent. The following specific findings and conclusions are:

Process Fluid Temperature - Basic resistance temperature device sensors are available which meet all the temperature sensing requirements, however some improvements in calibration and scaling control are required. Deficiencies in both electrical 'wireline' and slickline 'bomb' temperature logging tools exist, however several organizations are currently working on solutions.

Process Fluid Pressure - Process pipeline pressure sensors are available, however high accuracy hostile environment pressure sensors required for downhole measurements are not available. Several commercial sensors have been identified that have the basic performance (accuracy, stability, size) but require temperature hardening and other performance improvements. A DOE-DGE sponsored program is currently underway to harden both the basic sensor and the signal conditioning electronics of one identified commercial system (Paeroscientific) for operation up to 275°C. However, the final performance and scheduled commercial availability of the sensor are unclear.

Process Fluid Flow Rate - Single Phase Flow - Several promising single phase process pipeline flow rate sensors have been identified that might meet geothermal uphole measurement requirements, however downhole flow sensors are non-existent. Further, the need for a downhole flow sensor to identify producing and theft zones is considered very important for geothermal development. Acoustic flow sensors appear best suited to meet the downhole measurement applications based on their simplicity (no moving parts), accuracy, dynamic range and proven sensor hardenability.

Process Fluid Flow Rate and Enthalpy for Two Phase Flow - Commercial two phase flow sensing devices for low quality (χ<90%) are currently limited to by-pass sampling devices. To date, the geothermal development industry has been able to improvise using large separators with single phase flow sensors and/or the 'James' critical pressure technique. Unfortunately these currently employed methods require changing the fluid state. Numerous two phase mass flow rate measurement techniques for high temperature pressure and volume fluid are currently being developed by the nuclear energy industry for reactor safety tests. The techniques under development include using both single phase velocity sensors combined with density sensors such as turbines, drag disks and void fraction. contact probes and true mass flow rate sensors. Many of these techniques and tools, when and if developed and commercialized, could be used for geothermal process fluid measurements. One identified commercial insertion type fluid density sensor can operate in the high geothermal fluid temperature, however it may be subject to scaling. LBL is currently sponsoring a separate project to assess calorimeters for low quality two phase wellhead measurement applications.

Process Fluid Chemical Composition - Except for several slickline 'bomb' type borehole fluid samplers with marginal performance, there are no identified commercial process fluid chemical composition measurement systems that can function in the hostile geothermal fluid environment. An assessment of these deficiencies has been performed and a DOE-DGE sponsored program to develop the needed sensors is underway.

Downhole Formation, Producing Zone and Well Status Parameters - Five downhole geothermal parameters were identified by the geothermal development industry as requiring the highest priority for the development of geothermal energy. These are:

- Producing/fracture zone identification and orientation mapping (Priority 1)
- Method for well casing integrity inspection (Priority 1)
- Identification of multiple producing and/or theft zones (Priority 2)
- Formation porosity (Priority 2)
- Formation temperature during drilling operations (Priority 2)

There are currently no well logging tools available which can operate in the downhole hostile geothermal environment and provide the reservoir and production engineer with data on these critical parameters identified. Several non-hardened existing well logging tools that appear attractive for geothermal applications have been identified for each of the identified key downhole measurement parameters.

4.1 RECOMMENDATIONS

The following provides a list of recommendations to meet the measurement deficiencies identified:

Process Fluid Temperature - Though improvements in scale build-up and associated calibration problems exist, additional government sponsored projects for improved temperature sensors does not appear required.

Process Fluid Pressure - A more aggressive group of projects to improve and temperature harden promising pressure sensors for use in downhole well logging is required. More specific effort should be placed on improving/developing several commercial sensors wherein their signal conditioning electronics can be thermally protected in the event DOE-DGE's high temperature electronics development program requires additional time to develop and become commercially available.

Single Phase Process Fluid Flow Rate - Identified promising single phase process flow sensors should be evaluated in several geothermal process fluid (liquid) flow loops and steam flow loops. Several identified fluid density meters should be included in this experimental evaluation. This careful evaluation would lead to future improvements of the most promising sensor(s). A development program for a prototype downhole flow logging tool should be instituted. It would appear from the sensors and high temperature technology reviewed that either an acoustic pulsed doppler or travel time sensor technique would best meet the downhole geothermal requirement.

Two Phase Mass Flow Rate and Fluid Enthalpy - While deficiencies exist in the measurement of two phase fluid, the only recommended effort in this area is to periodically review and assess other programs attempting to solve this difficult problem and provide findings to industry. Consideration could be given to evaluate by-pass flow sampling techniques for two phase geothermal process lines and include in the by-pass lines the two phase mass flow sensors and density sensors identified for evaluation.

Fluid Chemical Composition - Recommendations have been performed by others and programs for their implementation are underway.

Downhole Formation, Production Zones and Well Status - An experimental evaluation of promising well logging techniques identified should be performed. This should be performed in a well logged, known, low temperature well or simulated well wherein each technique can be evaluated and compared. Using this 'benchmark' type experimental evaluation results, the most useful and developable tools should then be 'hardened' or developed for operation in geothermal hostile environment wells.

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APPENDIX A

GEOTHERMAL ENERGY DEVELOPMENT ORGANIZATIONS AND INDIVIDUALS CONTACTED

APPENDIX A

The following is a list of the organizations and individuals who were contacted to provide inputs and assistance in establishing the geothermal measurement performance requirements, their priorities and inputs on measurement methods they have used or considered to date. The organizations shown with an asterisk (*) are those where interviews were held and/or inputs were received.

1. Aminoil USA Inc.*
   Santa Rosa, CA
   - George Fyre
   - James Grubb
   - Rodger Wall

2. Chevron Resources Company*
   San Francisco, CA
   - Dave Butler
   - Al Cooper
   - Don Hill

3. Chevron Oil Field Research Company
   La Habra, CA
   - John Duerksen
   - John Martin
   - Chuck Newman
   - A. (Turk) Timur

4. Idaho National Engineering Laboratory*
   EG&G-Geothermal Program Group
   Idaho Falls, ID
   - Ray Gould
   - Susan Prestwich
   - Rodger Stoker

5. Lawrence Livermore Laboratory*
   Livermore, CA
   - Al Duba
   - Paul Kasamyer
   - John Morse
   - Hank Weiss

6. Los Alamos Scientific Laboratory*
   Los Alamos, NM
   - Bert Dennis
   - Mark Mathews
   - John Rowley

7. Magma Power (Imperial Magma)*
   Escondido, CA
   - Tom Hinrichs

8. Phillips Petroleum Company*
   Geothermal Operations
   Salt Lake City, UT
   - C.W. (Bill) Berge
   - Gary Crosby
   - Don Harbin
   - Earl Hoff
   - Dick Lindser

9. Republic Geothermal Inc.*
   Santa Fe Springs, CA
   - Don Campbell
   - Corky Isselhardt
   - Don Michels
   - Charlie Morris
   - Bob Verity
   - Mike Walker

10. Rodgers Engineering Company*
    San Francisco, CA
    - Don Brewer
    - Jim Kuwada

11. San Diego Gas and Electric
    Geothermal Energy Group
    San Diego, CA
    - Bill Jacobson

12. Shell Oil Company/Production Division
    Houston, TX
    - Don R. Lindsay
    - Charles F. Mathews

13. Sunoco Energy Developement Company
    Dallas, TX
    - Alan O. Ramo

14. Thermal Power Company*
    San Francisco, CA
    - Jake Rudisill

15. Thermogenics, Inc.*
    Santa Rosa, CA
    - Steve Davies
    - Ray Jensen
    - Douglas B. Jung

16. Union Oil Company* - Geothermal Division
    Los Angeles & Santa Rose, CA
    - Mike Barnes
    - Mohinder Gulati
    - Carel Otte
    - Del Pyle

17. Union Oil Company/Union Research Center
    Brea, CA
    - Bob Ransom

18. University of Texas
    Energy Research Institute
    Austin, TX
    - Myron Dorfman

APPENDIX B

SENSOR MANUFACTURERS CONTACTED

APPENDIX B

TEMPERATURE TRANSDUCER MANUFACTURERS CONTACTED

NAME	LOCATION	TELEPHONE
ARi Industries	Franklin Park, IL	312 + 671-0511
Barber-Coleman	Rockford, IL	815 + 968-6833
Barton-ITT	Monterey Park, CA	213 + 961-2547
Big Three Industries	S. Plainsfield, NH	201 + 757-8300
BLH Electronics	Waltham, MA	617 + 890-6700
Brooklin Thermometer	Farmingdale, NY	516 + 694-7610
Celesco Transducer Products	Canoga Park, CA	213 + 881-6860
C.S. Gordon Company	Richmond, IL	815 + 678-2211
Fenwal Electronics	Framingham, MA	617 + 872-8841
Fischer and Porter Company	Warminister, PA	215 + 674-6000
Foxboro Company	Foxboro, MA	617 + 543-8750
Hi-Cal Engineering	Santa Fe Springs, CA	213 + 698-7785
Markel Company	Chicago, IL	312 + 826-1700
Matthey Bishop, Inc.	Malvern, PA	215 + 648-8000
Minco Products, Inc.	Minneapolis, MN	612 + 571-3121
Omega Engineering, Inc.	Stamford, CT	203 + 359-1660
Rosemont, Inc.	Minneapolis, MN	612 + 941-5560
Semco, Inc.	N. Hollywood, CA	213 + 982-1400
Spectro Systems, Inc.	Springfield, VA	703 + 321-9240
Sybron-Taylor Corporation (Consumer Industrial Products Div.)	Arden, NC	704 + 684-8111
Thermometrics, Inc.	Edison, NJ	201 + 287-2870
Victory Engineering	Springfield, NJ	201 + 379-5900
W. Wahl Corporation	Los Angeles, CA	213 + 641-6931
Weed Instrument Company	Elgin, TX	512 + 285-3411
W.H. Keseler Company, Inc.	Westbury, NY	516 + 334-4063
Weston Instruments	Newark, NY	
Yellow Springs Instruments	Yellow Springs, OH	513 + 767-7241

APPENDIX B

PRESSURE TRANSDUCER MANUFACTURERS CONTACTED

NAME	LOCATION	TELEPHONE
Barton-ITT	Monterey Park, CA	213 + 283-6501
Bell & Howell, CEC Division	Pasadena, CA	213 + 796-9381
BLH Electronics	Waltham, MA	617 + 890-6700
Bourns Inc./Instrumentation Div.	Riverside, CA	714 + 781-5148
Celesco Transducer Products	Canoga Park, CA	213 + 884-6860
Cognition, Inc.	Mountain View, CA	415 + 969-8300
Data Instruments, Inc.	Lexington, MA	617 + 861-7450
Fischer and Porter	Warminister, PA	215 + 674-6000
Foxboro Company	Foxboro, MA	617 + 543-8750
Gulton-Servonic/Instrumentation Div.	Costa Mesa, CA	714 + 642-2400
Heise-Industrial Valve & Instrument Division of Dresser Industries	New Town, CT	203 + 426-4406
Hewlett-Packard	Palo Alto, CA	415 + 856-1501
Kaman Sciences Corporation	Colorado Springs, CO	303 + 599-1500
Mensor Instruments	San Marcos, TX	512 + 392-6091
Paroscientific, Inc.	Redmond, WA	206 + 883-8700
Precise Sensors	Monrovia, CA	213 + 358-4578
Robinson-Halprin Company	Plymouth Meeting, PA	215 + 825-9200
Rosemount, Inc.	Minneapolis, MN	612 + 941-5560
Schaevitz Engineering	Pennsauken, NJ	609 + 662-8000
Sensor-Metrics, Inc.	Van Nuys, CA	213 + 988-6076
Setra Systems, Inc.	Natick, MA	617 + 655-4645
Sparton Southwest, Inc.	Albuquerque, NM	505 + 898-1150
Sunstrand Data Controls, Inc.	Redmond, VA	206 + 885-3711
Sybron-Taylor Corporation (Process Control Division)	Rochester, NY	716 + 235-4893
Teledyne Taber	N. Tonawanda, NY	716 + 694-4000
Validyne Engineering Corporation	Northridge, CA	213 + 886-8488
Viatran Corporation	Grand Island, NY	716 + 773-5148
Vernitech	Deer Park, Long Island, NY	516 + 586-5100

APPENDIX B

SINGLE PHASE FLOW TRANSDUCER MANUFACTURERS CONTACTED

NAME	LOCATION	TELEPHONE
Badger Meter, Inc.	Tulsa, OK	918 + 584-4471
Baird Controls, Inc.	Naperville, IL	312 + 355-3040
Barton-ITT	Monterey Park, CA	213 + 961-2547
Bennett Gervase, Inc. (Gil-Flow Sensor)	Muskegan, MI	616 + 739-9421
Brooks Instrument (Emerson Electric)	Hatfield, PA	215 + 368-2000
Controlotron Corporation	Long Island, NY	516 + 249-4400
Dieterich Standard Corporation (Annubar Flow Sensor)	Bolder, CO	303 + 449-9000
Disa Electronics	Franklin Lakes, NJ	201 + 891-9460
Dupont Company, Instrument Products	Monrovia, CA	213 + 357-2111
Eastech Incorporated	S. Plainsfield, NJ	201 + 561-1000
Electronic Flo-Meters, Inc.	Dallas, TX	214 + 349-1982
Engineering Measurement Company	Bolder, CO	303 + 447-0550
Fischer and Porter Company	Warminister, PA	215 + 674-6000
Flow Dyne Engineering, Inc.	Fort Worth, TX	817 + 732-2858
Flow Technology, Inc.	Phoenix, AR	602 + 268-8776
Foxboro Corporation	Foxboro, MA	617 + 543-8750
Fox Valve Development Co., Inc.	E. Hanover, NH	201 + 887-7474
Hersey Products, Inc.	Spartanburg, SC	803 + 578-3800
J-Tech Associates	Cedar Rapids, IA	319 + 366-7511
Leeds and Northrop	North Wales, PA	215 + 643-2000
Mapco, Inc.	Tulsa, OK	918 + 584-4471
Polysonics, Inc. (Tech/Sonics)	Houston, TX	713 + 623-2134
Ramapo Instrument Corp., Inc.	Montville, NJ	201 + 263-8800
R.M. Nikkel Company	Foster City, CA	415 + 573-0511
Sybron-Taylor Corporation (Process Controls Div.)	Rochester, NY	716 + 235-5000
Tech Tube Corporation	Houston, TX	713 + 623-0638

FLUID DENSITY TRANSDUCER MANUFACTURERS CONTACTED

Agar Instrumentation, Inc.	Houston, TX	713 + 461-2427
Automation Products, Inc.	Houston, TX	713 + 869-1485
Barton-ITT	Monterey Park, CA	213 + 961-2547
Halliburton	Duncan, OK	405 + 251-3081
Micro-Motion, Inc.	Bolder, CO	303 + 499-6400
Ramsey Engineering Company (Texas Nuclear Div.)	Austin, TX	512 + 836-0801

APPENDIX C

WELL LOGGING EQUIPMENT DEVELOPERS AND MANUFACTURERS CONTACTED

APPENDIX C

WELL LOGGING EQUIPMENT DEVELOPERS AND MANUFACTURERS CONTACTED

Name	Location
Agnew and Sweet	Bakersfield, CA
Boston Insulated Wire & Cable Co. (EM Cable)	Boston, MA
Consolidated Products (South Bay Cable Div.)(EM Cable)	Idyllwild, CA
Denver Research Institute	Denver, CO
DIA-LOG Company	Whittier, CA
Dresser-Atlas Industries	Houston, TX
Gearhart-Owen Industries	Fort Worth, TX
Geophysical Research Corporation	Tulsa, OK
E.M. Blue's Sons, Inc. (EM Cable)	Houston, TX
Halliburton Services	Duncan, OK
Kuster Company	Long Beach, CA
Los Alamos Scientific Laboratory (Geothermal Operations Group G-4)	Los Alamos, NM
N.L. McCullough Services (Triangle Services)	Houston, TX
Prodelco Engineering Ltd. (Forgan Jones Ltd)	Newmarket, Auckland, New Zealand
Rochester Corporation (EM Cable)	Culpeper, VA
Sandia Laboratories (Geothermal Technology Div. 4736)	Albuquerque, NM
Schlumberger Well Services	Houston, TX
Seismograph Service Corp. (Birdwell Div)	Tulsa, OK
Shell Development Company	Houston, TX
S.I.E.	Fort Worth, TX
Simplec Manufacturing	Dallas, TX
Sperry-Sun	Houston, TX
Systems, Science and Software	San Diego, CA
U.S. Geological Survey	Menlo Park, CA
Vector Cable Company (EM Cable)	
Well Reconnaissance, Inc.	Dallas, TX
Welex	Houston, TX
W.T.C. Worth Systems	Fort Worth, TX